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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 Mail Stop P-130A, Washington, DC 20555.

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Period Covered: March-April 1984

1.0 Summaries of Events

1.1 Surveillance Testing Initiates Complex Event Involving Loss of Vital Bus

At Salem Unit 2,* during routine surveillance testing at 2:13 a.m. on March 18, 1984, a loss of the 2B 4 kV vital bus occurred while paralleling the 2B emergency diesel generator with the grid. The bus differential protection relay actuated, which in turn actuated the multi-trip relay and tripped open the 2B emergency diesel generator breaker and the 4 kV vital bus infeed breaker. The plant was verified to be in a stable condition. Although the individual rod position indication (IRPI) failed at zero, and the rod bottom lights illuminated, reactor power remained steady at 100%. The plant was maintained stable while the IRPI and rod bottom indication were restored. At 6:10 a.m., a unit shutdown was commenced in accordance with the technical specifications, due to the inoperability of three containment isolation valves. The loss of the 2B 4 kV vital bus was attributed to paralleling the 2B emergency diesel generator out-of-phase. Testing verified that the bus, breakers, relays and all equipment were undamaged by the transient. The bus was reenergized at 11:23 a.m. The containment isolation valves were restored to an operable status, and the reactor shutdown was terminated. The event is discussed in detail below.

During routine power operations on March 18, surveillance testing of the 2B emergency diesel generator was in progress. The diesel had been successfully started, and the generator was being synchronized with the grid. At 2:13 a.m., closed indication of the diesel generator output breaker was observed in the control room, followed by an almost instantaneous opening. Approximately 10 seconds later, the diesel output breaker again indicated closed, and again instantaneously opened. This time, the diesel breaker opening was accompanied by the opening of the 2B 4 kV vital bus infeed breaker and, consequently, the loss of the 2B 4 kV vital bus. Other indications observed in the control room immediately following the occurrence were: 2B emergency diesel generator "start" indication; 2B diesel generator output breaker "open" indication; both station power transformer infeed breakers "open" indication; 2B 4 kV vital bus differential protection and 2B 4 kV vital bus undervoltage alarms on the overhead annunciator; IRPI failure at zero; illumination of all rod bottom lights; and stable primary and secondary plant parameters, with reactor power at 100%. Shift personnel immediately verified equipment/system status, and confirmed that the plant was in a stable condition. Personnel were dispatched to verify relay actuations in the switchgear room. The shift then directed their attention to identifying applicable technical specifications and the actions necessary to comply with the limiting conditions for operation (LCO) for one inoperable vital bus.

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*Salem Unit 2 is a 1106 MWe (net) PWR located in New Jersey, 20 miles South of Wilmington, Delaware, and is operated by Public Service Gas and Electric.

At approximately 2:30 a.m., the actuated relays were identified, and it was determined that the diesel breaker and the vital bus infeed breaker had tripped as the result of bus differential current protection. Orders were given not to reenergize the bus until a thorough investigation of the bus and of the supplied loads could be performed.

Technical specification LCOs require that the control rod position indication system be operable and capable of determining the control rod positions within +-12 steps. It was determined that this was the most restrictive LCO applicable, due to the loss of power to the IRPI; therefore, efforts were directed to restoring power to the IRPI system.

Knowing that the plant was in stable condition, and realizing that an improperly monitored shutdown transient was unsafe when compared to steady state conditions, the Senior Shift Supervisor directed that the unit be maintained stable while other possible causes could be eliminated. He also ordered a manual reactor trip to be initiated immediately in the event of any transient. At 3:44 a.m., after checking all possible causes, it was determined that the IRPI system failure was due to loss of the normal power supply. The alternate power supply breaker was ordered closed, and at 4:00 a.m., the IRPI and rod bottom indications were returned to operable status.

Technical specifications also require three operable emergency diesel generators. With one diesel generator inoperable, the action statement requires that the two remaining diesel generators be demonstrated operable within 1 hour, and at least 8 hours thereafter. In addition, the inoperable diesel generator must be returned to an operable status within 72 hours, or the unit must be in hot standby within the next 6 hours and in cold shutdown within the following 30 hours.

At 4:11 a.m., the surveillance requirements were completed and the operability of 2A and 2C emergency diesel generators was verified. Although the surveillances were 58 minutes overdue, the verification was performed as soon as the IRPI system was returned to service.

At this point, the most limiting condition for operation was determined to involve the inoperability of containment isolation valves, the reactor coolant pump seal water return header stop valve, the charging header motor-operated stop valve, and the fire protection valve, due to the loss of the 2B 4 kV vital bus. Technical specification action statements required that the inoperable valves be restored to an operable status within 4 hours, or be in hot standby within the next 6 hours and in cold shutdown within the following 30 hours. These action statements became effective at 2:13 a.m. At 6:10 a.m., a controlled plant shutdown was initiated to comply with the action requirements.

The event was attributed to paralleling the 2B emergency diesel generator out-of-phase. The current and voltage transient, caused by the phase mismatch, resulted in actuation of the bus differential protection relay. This, in turn, actuated the multi-trip relay, which tripped open the diesel generator breaker and the 4 kV infeed breaker, isolating the bus and protecting it from damage.

Since the entire event occurred in 10 to 14 seconds, the exact sequence of events, observations and actions (at the diesel panel) could not be confirmed by the operator, although the following is the most probable scenario. The operator had performed all of the preliminaries required by the procedure and proceeded with the diesel starting sequence. With the diesel running, he increased the generator voltage to a value slightly higher than that of the bus. He then closed the breaker at the "12 o'clock" position on the synchroscope. Although not confirmed by the operator, it appears that an inadvertent manual trip was initiated on the breaker (possibly by turning the control switch too far) while returning the switch to the "neutral" position. A manual trip is the only action that would allow the subsequent reclosure of the breaker.

Investigation discovered that the 2B diesel generator breaker "open" indicating light (on the local control panel) was not functioning, which could have caused confusion as to the status of the breaker. Observing no "closed" indication, and thinking that the breaker did not close (not realizing that it had closed and been inadvertently tripped open), the operator then attempted to close it when the synchroscope reached the "12 o'clock" position again. At this point, one of two things occurred. Either the operator attempted to reclose the breaker before the breaker closing springs had completely charged, in which case the closing of the breaker (after the springs were fully charged) came sometime after the point where the generator was sychronized with the bus; or, trying to synchronize by catching the synchroscope on the first pass, and not allowing the synchroscope to complete a few revolutions, resulted in incorrect indication of synchronization.

Following the event, all 4 kV breakers, including the diesel generator breaker, were racked out and inspected for possible damage. The 2B 4 kV bus was meggered phase-to-ground; each load was meggered phase-to-ground; the phase-to-phase resistance of each load was checked; the synchroscope was checked for proper indication and operation; and the bus differential relay was checked for proper operation and for correct settings.

The 2B diesel generator breaker was verified to be operating correctly. All inspections and tests were satisfactory. No problems with the bus, loads, breakers or relays could be found. The 2B diesel generator breaker "open" indicating light was replaced. All other diesel breaker indicating lights (including those associated with the other diesel units) were verified to be operational.

On January 5, 1983, Unit 1* had experienced an unexplained trip of the 1B 4 kV vital bus infeed breakers on bus differential relay protection. Because of this, and since the inadvertent manual trip on March 18, 1984 could not be verified, an investigation into the 1983 event is continuing, to ensure that no undetected problems exist with the bus differential relay protection circuitry. (Refs. 1 and 2.)

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*Salem Unit 1 is a 1079 MWe (net) PWR located in New Jersey, 20 miles south of Wilmington, Delaware, and is operated by Public Service Gas and Electric.

1.2 Main Steam Check Valve Failures

On April 27, 1984 at Trojan,* an automatic reactor scram occurred due to C steam generator low-low level following a plant test in which the north main feedwater pump was manually tripped. The potential for this scram was anticipated in the test. The plant was scheduled to shut down that day for refueling. While the plant was stabilized in hot standby, an operator discovered that the B and D main steam nonreturn check valves (MSCVs) had failed to close. The valves were closed manually and will be modified during the 1984 refueling outage to prevent recurrence. (These are Atwood-Morrill 28-in OD-type main steam swing check valves.)

The plant test had been conducted to evaluate the capability of the automatic turbine generator runback following loss of one main feed pump (MFP). The runback at a rate of 1% per second to a plateau load of 70% is intended to prevent a reactor scram following the loss of one MFP. The reactor was at 100% power when the north MFP was manually tripped at 6:26 p.m., and 56 seconds later the reactor automatically scrammed on C steam generator low-low level. The reactor had reached 78% power at the time of the trip. By test procedure, no operator action was taken from the time that the pump was tripped until the reactor scrammed. The plant was then stabilized in hot standby.

After the plant was stabilized, an operator inspected the main steam nonreturn check valves. He found the A MSCV fully closed, the B MSCV fully open, the C MSCV greater than 10° closed, and the D MSCV apparently open and missing the north side counterweight and arm assembly that also indicated valve position. The operator immediately closed the B and C MSCVs. The Shift Technical Adviser and Assistant Shift Supervisor inspected the D MSCV and determined the valve to be open as indicated by the angle drawn through the key ways in the shaft. The counterweight and arm assembly had fallen onto the feedwater piping below the valve. An operator closed the valve using a strap wrench on the shaft.

The MSCVs at Trojan have a history of remaining open following a reactor scram. The original valve design included two lever arms, one on each end of the valve shaft. Each arm had a counterweight attached to it and the arms were oriented such that the counterweight acted to balance the weight of the valve disc. This design was to prevent valve flutter under low steam flow conditions. On March 17, 1983, during testing of the operability of the main steam isolation valves, all four MSCVs stuck open when each one should have closed when steam flow decreased. An analysis was performed to determine if the valves would have closed under reverse steam flow conditions rather than no flow. It was concluded that there may have been insufficient torque to close the valves from the full open position when seated against the disk stop. It was further determined that the valves would close under reverse flow if they had closed by more than 10°.

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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.

When the valve packing had been removed during the 1983 refueling outage, it was found to be dry and brittle. It had last been repacked in 1981, when the maintenance schedule for packing replacement was every two years. The maintenance schedule has been revised to replace the packing every year during refueling. Other corrective actions were to increase the inner diameter of the gland follower to allow easier movement along the shaft, and implementation of a documented testing program to adjust the packing before and after heatup. During the 1983 shutdown, one counterweight was removed from each valve and the other counterweight position moved to the inner end of its lever arm.

On September 21, 1983 the D MSCV failed to close following a reactor scram. The three other valves closed by more than 10°, which had been established as the operability criterion to ensure closure under reverse steam flow. The north arm with the counterweight on the D MSCV was rotated 180° along the shaft so that the counterweight would act to close the valve.

On October 7, 1983 the C MSCV failed to close following a reactor scram. The A and B MSCVs closed half way, and the D MSCV closed fully. The counterweights on the A, B, and C MSCVs were rotated 180°, as D's had been previously; all four valves were tested and closed satisfactorily.

The valves failed to close on April 27, 1984, because of packing induced friction along the valve shafts. The type of packing and number of rings used determines the frictional forces along the shaft, and its effectiveness as a barrier to steam leaks. In addition, the failure of the D MSCV counterweight assembly, discovered during the April 27 event, was caused by a missing setscrew.

A licensee analysis for the MSCVs was completed on May 4, 1984. To reduce frictional forces on the valve shafts, the number of graphite braided filament packing rings will be reduced from ten to six, and the applied gland nut torque will be limited to 60 foot-pounds or the minimum torque required to allow operation with the maximum allowed leakage. This new packing configuration will decrease the frictional torque on the valve shaft by 23%. The analysis determined that fewer rings should also improve steam leak tightness since the packing will not compress as much. The second lever arm on the valve shafts will also be rotated 180° and a counter-weight added to the arms to assist in the closing of the valves. The final configuration of all four MSCVs will be with two counterweights, one on each side of the valve and both acting such that the gravity will help to close the valves. This design will increase the closing torque by 22%. Some adjustments during startup testing may have to be made to keep the valves from fluttering under low steam flow conditions.

The counterweight arm assemblies are held on the valve shafts by a setscrew that tightens against one of the keys in the shaft. The arm setscrew was missing from the collar of the D MSCV collar counterweight when the arm was found on the feedwater piping. The setscrew was in place in the second lever arm but the collar was loose around the shaft. The setscrews were verified to be in place on both arms on the three remaining valves and all the collars were found to be tight along the valve shafts. The tightness of the setscrews will be verified when the valve modifications are complete, and will be verified by procedure each time the valves are packed on an annual basis. (Ref. 3.)

1.3 Main Generator Hydrogen Explosion and Fire

On March 19, 1984, a hydrogen explosion and fire occurred in the main generator housing at Rancho Seco while the plant was operating at 85% power. At approximately 8:50 p.m., a turbine steam exhaust fan tripped (2E1 bus) on an electrical ground fault. This caused the power supply breaker to the 2E1 bus to open and deenergize the bus. Attempts to reclose this breaker failed. Among the equipment powered from the 2E1 bus is the hydrogen seal oil pump, which supplies oil for the hydrogen side seals of the Westinghouse main generator. Hydrogen gas is used to cool the main generator. By plant procedures, the main generator can continue operation with the air side seal oil pump maintaining shaft seals. Nevertheless, the loss of the hydrogen seal oil pump allowed the escape of hydrogen from the generator.

At approximately 9:49 p.m. after an equipment attendant checked some instrumentation in the turning gear area, a small explosion occurred. The equipment attendant called the control room and reported the explosion. The control room operators began to decrease reactor power at the maximum rate. At 9:50 p.m., a major explosion and subsequent fire occurred in the excitor to generator housing interface, and the turbine and reactor were manually tripped. Reactor power at the time of the trip was 85%. The fire was extinguished by the carbon dioxide fire protection system within 14 minutes of the explosion. At 9:53 p.m. the incident was declared an unusual event (the least severe of the four categories in the NRC's emergency classification system).

All systems responded normally to the reactor trip except one turbine bypass valve. This turbine bypass valve stuck open and was identified and shut within 6 minutes. The reactor coolant system experienced a temperature loss of 80°F in the 6 minutes that the bypass valve was stuck open, which is within the technical specification cooldown rate of 100°F/hr.

At approximately 10:57 p.m., with the plant in a stable condition, the control room operators perceived a total loss of non nuclear instrumentation (NNI) power. (It was later found that only a partial loss of NNI power had occurred, due to a degraded inverter coupled with the failure of a -24 V dc power supply.) The operators' actions included following the casualty procedure for the complete loss of NNI power. This procedure, in part, entails initiation of high pressure safety injection. The reactor coolant system's pressure increased due to the high pressure injection and resulted in a pressurizer code safety valve lifting prematurely at 2360 psig (setpoint is 2500 psig). The reactor coolant system pressure decreased and the pressurizer code safety valve reseated; pressure increased again due to continued high pressure safety injection, and the same pressurizer code safety valve again lifted. When the pressurizer code safety valve lifted for the second time, the high pressure safety injection valves were being throttled. Reactor system pressure was then controlled per

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*Rancho Seco is an 873 MWe (net) PWR located 25 miles southeast of Sacramento, California, and is operated by Sacramento Municipal Utility District.

procedure. Four minutes after the perceived total loss of NNI power, NNI power was regained, and high pressure injection was secured. Due to the loss of NNI power, the incident was upgraded to an alert status; when NNI power was regained, the alert status was downgraded to an unusual event.

The event was maintained at an unusual event status by the licensee because the supply of carbon dioxide had been used to extinguish the fire. Fire watches were posted in all areas where carbon dioxide is used for fire protection. The event was secured from an unusual event at 6:00 p.m. after the carbon dioxide tanks had been refilled. (Refs. 4 and 5.)

This event remains under investigation by the licensee and the NRC, and will be updated in a future issue of Power Reactor Events.

1.4 Main Steam Safety Valve Failure

On March 2, 1984, at 12:20 p.m., Davis-Besse Unit 1* was operating at approximately 99% power. The plant was in full automatic control. During periodic steam feedwater rupture control system (SFRCS) surveillance testing, a previously undetected SFRCS channel failure resulted in closure of a Loop 2 main steam isolation valve (MSIV). This caused an increase in feedwater to the other steam generator (SG), which overcooled that side of the reactor. Flux increased because of the moderator cooling. The reactor scrammed on high flux approximately 13 seconds after MSIV No. 2 closed.

Following the reactor scram, steam pressure on SG No. 2 did not stabilize as would normally be expected. It was determined through local observation that main steam safety valve (MSSV) SP17A4, with a set pressure of 1070 psig, had not fully closed on the No. 2 steam line. Manual actuation of SFRCS isolated SG No. 2. After auxiliary feedwater (AFW) isolation, SG No. 2 boiled dry and depressurized to atmospheric pressure in approximately 5 minutes. This depressurization caused the reactor coolant system (RCS) to exceed the normal cooldown limits for a short time. Plant cooldown was conducted slowly with SG No. 1 to minimize the temperature differential between the tubes and the shell of the dry No. 2 SG. After sufficient cooling, at approximately 340°F RCS temperature and about 19 hours after the start of the event, the failed MSSV was replaced. When operators attempted to restore level in SG No. 2, the AFW valve failed to open electrically. It was opened manually, and SG No. 2 level was restored to operable status. Within about 24 hours after the start of the event, the decay heat removal system was placed into operation, and the plant was then brought to cold shutdown. It was determined later that another MSSV (SP17A1) on the No. 2 steam line had failed to open when it should have.

The incident had been declared an unusual event (the least severe category in the NRC's emergency classification system) at 12:40 p.m. on March 2, and this classification was terminated at 10:50 a.m. on March 3, 1984. The sirens of the offsite emergency notification system were activated twice about the time the incident began, but neither siren activation was associated with the incident. The first sounding of the sirens was for a periodic test, and the second sounding was inadvertent. These soundings attracted significant local media and public attention to the event.

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*Davis-Besse Unit 1 is an 874 MWe (net) PWR located 21 miles east of Toledo, Ohio, and is operated by Toledo Edison.

The cause of the MSIV closure was a failed optical isolator in a relay driver card for a relay in SFRCS Channel 4. This failure, undetected and in conjunction with normal testing on another channel, resulted in a close signal to MSIV No. 2. During troubleshooting, a wiring anomaly was found in the circuitry for MSIV No. 2. This anomaly was the reason the failed relay driver card had not been detected. There were both equipment failure and installation/construction error associated with the MSIV closure. The cause of the excessive cooldown rate of the RCS was equipment failure. The failed MSSV released steam from SG No. 2 at a rate causing excessive cooldown.

The two MSSV malfunctions, SP17A1 and SP17A4, were both equipment failures. MSSV SP17A4 failed due to the failure of a cotter pin that secures the release nut in place at the top of the stem. The failure of the cotter pin allowed the release nut to spin down the stem while the valve was open. The nut contacted the manual lifting device and prevented the valve from closing. The cause for the failure of MSSV SP17A1 is unknown at this time. When tested subsequent to its failure to open, it lifted early and inconsistently. It has been gagged and will be repaired or replaced during the next refueling outage.

The licensee replaced MSSV SP17A4, and the cotter pins in all other MSSVs were replaced with stainless steel pins. Maintenance procedures were modified to ensure new pins are used after any maintenance or testing in the future. The RPS high flux trips must be set at less than 99.69% of rated thermal power with MSSV SP17A1 inoperable.

Although the cooldown rate was within technical specification limits, plant procedures involving plant shutdown and cooldown and steam supply system ruptures have been modified to incorporate lessons learned from this event to give better control of this type of cooldown.

The effects of the SG No. 2 boiling dry were analyzed, and it was concluded that the transient was within SG design limits. The effects of high main steam flow from SG No. 1 when MSIV No. 2 closed also was analyzed. It was concluded that some tubes (approximately 100) may have become unstable for a period of seconds. As corrective action, the suspect tubes will be eddy current tested during the next refueling outage.

The failure of the AFW valve was attributed to the torque switch setting. After it had been opened manually, troubleshooting found no mechanical problems and the valve operated properly.

The AFW valve motor operator torque switch settings were changed from 1.5 open and close to 1.0 close and 1.5 open. This is to prevent the valve disc from being jammed into its seat. This change was also made to the AFW valve for SG No. 1.

The faulty relay driver board in SFRCS Channel 4 was replaced. The wiring anomaly was corrected and verified not to exist in the circuitry for MSIV No. 1.

NRC's Region III office issued a Confirmatory Action Letter on March 3, 1984, which confirmed the licensee's commitments to investigate the equipment failures that occurred and to evaluate the effects of the event on the plant. Following these evaluations and equipment repairs, the plant resumed operations on March 8, 1984. (Refs. 6-8.)

1.5 Water Hammer in Feedwater Piping and Subsequent Scram Due to Feedwater System Problems

At Salem Unit 2* on April 6, 1984, while stroke testing feedwater regulating valve 23BF19 with the reactor in hot standby, the main feedwater line check isolation valve apparently failed open. This caused a water hammer in the feedwater and condensate system which resulted in damage to pipe hangers, instrumentation and insulation, and in displacement of the feedwater flow element. The licensee initiated a detailed evaluation of the event, including steam generator inspection, valve disassembly and inspection, stress analysis of the piping, nondestructive examination (NDE) of piping hangers, etc. After a 29-day period to conduct investigations and make repairs, successful restart of the unit began on May 5, 1984.

Between each feedwater regulating valve and steam generator (SG) at Salem Unit 2, there are two valves in the main feedwater line, an isolation valve (BF21) and a stop check valve (BF22). Valve BF21 is usually open. Normally, the function of the stop check valve is to prevent reverse flow from the SG whenever the main feedwater system is not in operation.

On April 6, while in hot standby, inservice testing was in progress. The test procedure required each feedwater regulating valve (21-24 BF19) and bypass valve (21-24 BF40) to be tested for stroke time determination. Testing had been satisfactorily completed on 21BF19, 21BF40, 22BF19 and 22BF40. Apparently, the stop check valve in Loop 3 (23BF22) had failed to close against SG pressure (1000 psig). When feedwater regulating valve 23BF19 was opened for its stroke time test, a fast reverse flow developed due to high differential pressure across the regulating valve (1000 psig on one side and 500 psig on the other). The reverse flow appears to have subsequently slammed the check valve shut, which generated pressure waves resulting in water hammer. These pressure waves propagated through the piping system and caused damage to pipe supports in some locations. The root cause of this event was attributed to the stuck check valve along with an inadequate surveillance procedure. The check valve failure may have been caused by crud buildup, since magnetite product was found during post-event valve inspection.

In reviewing this event, the NRC found that Integrated Operating Procedure (IOP) 8, Maintaining Hot Standby (HSB), requires that the procedure for placing the condensate system in service for cleanup be followed if the unit will remain in HSB for more than 3 hours. The unit had been in HSB about 7 hours. The first step of the procedure requires completion of a valve lineup which requires that 23BF13, the isolation valve upstream of 23BF19, be closed. Although the

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*Salem Unit 2 is a 1106 MWe (net) PWR located in New Jersey, 20 miles south of Wilmington, Delaware, and is operated by Public Service Electric and Gas.

condensate cleanup strainer was in service at the time of the water hammer, the 23BF13 valve was not closed. Had this procedure been followed and the 23BF13 valve been closed while stroke testing 23BF19, it is likely that the water hammer would not have occurred or would have at least been reduced in severity, since there would have been little or no volume to receive the reverse flow from the No. 23 SG when the immediately downstream valve 23BF19 was stroke tested with the 23BF22 not fully closed. It was also noted that the licensee had added a motor operator to the Unit 2 BF22 valves during the last refueling outage to permit rapid isolation in the event of a feedwater line break. However, no routine use of these valves was incorporated into the licensee procedures. The licensee has since revised procedures to require that both the BF13 and BF22 valves be closed to prevent recurrence.

The licensee took aggressive corrective actions after the event. A task team consisting of personnel from station and engineering groups was formed. The entire feedwater line and SG were visually inspected. NDE testing was performed on selected locations. In parallel with the inspections, the analytical group, helped by an outside consultant, simulated the water hammer event. Preliminary results indicated that both initial peak compression waves (downstream side of 23BF22) and refraction waves (upstream side of 23BF22) varied from about 500 to 700 psi in amplitude. The assessment and modeling generally agreed with the observation of piping damage which was located mainly between the No. 23 SG and regulating valve 23BF19. Since the SG has a very large water volume compared with the feedwater piping system, the effect of pressure waves on SG internal structure was not expected to be significant. Damage discovered during a walk down of the feedwater lines for all four steam generators included:

-- Major distortion of the piping support system, consisting of rigid struts, spring hangers and snubbers, occurred between the No. 23 SG and the air-operated feedwater regulating valve (23F19).

-- Distortion of the cam positioner of inline air-operated control valve 23BF19, and distortion of the actuation position transmitter and yoke of bypass air-operated valve 23BF40.

-- Distortion of trunions on the feedwater piping inside containment.

Following a 17-day outage to investigate and make repairs to the No. 23 SG feedwater line, the reactor came on line at 3:54 p.m. on April 23. On April 23 and 27, turbine and reactor scrams were experienced during unit startup operations. Post-scram review procedures proved adequate in detecting a questionable SG feed flow indication following the April 23 event, and in detecting a plugged sensing line following the April 27 event. When problems with feed flow indication continued during startup on April 28, radiography testing revealed that an SG feedwater flow nozzle had become dislocated, apparently during the feedwater water hammer which had occurred on April 6. A licensee investigation of post-scram review procedures determined that the procedures were adequate and had identified the questionable feed flow indication, but that the explanation for the indication had been incorrect. The events are described below.

On April 23, 1984, unit startup operations were in progress. All SG feedwater level control systems at Salem Unit 2 were in automatic, with the No. 23 SG experiencing 15% to 20% level oscillations. At 4:00 p.m., a turbine trip and reactor trip occurred due to high-high level in the No. 23 SG.

During automatic operation, the SG feedwater level control system is normally a three-element control system. It receives signals from steam flow, feed flow and steam generator level error. At very low power levels, the control system senses only the steam generator level error signal, because of the minimum steam flow and feed flow conditions. A steam generator level change has to occur before the level controller can respond. This results in sluggish response and overcompensation by the controller and, consequently, relatively large deviations from the level setpoint.

Following this particular occurrence, valves 23BF19 and 23BF40 (No. 23 SG feedwater control valve and bypass valve, respectively) were stroked. Both had been damaged in the feedwater system hammer event on April 6, but had been repaired and tested satisfactorily. Investigation indicated that the packing was slightly "cocked" on 23BF40, causing the valve to bind and subsequently pop open. It was felt that this could possibly be contributing to the magnitude of the level swing associated with the No. 23 SG.

Permission to perform a unit startup was given pending completion of repairs to valve 23BF40 packing. Instructions were also issued to the operators to establish a dummy load on the reactor using the MS10 valves (main steam atmospheric vents), and to place SG feedwater level control in manual if the level was observed to spike higher than 50% by narrow range level indication. In addition, because of previous problems with level control during low power levels, an engineering investigation into possible future system changes was requested.

Reactor startup was begun on April 24, but a reactor scram occurred before the corrective actions taken (following the April 23 scram) could be verified to have remedied the level instability of the No. 23 SG. (The April 24 scram was caused by a turbine stop valve opening late, with a subsequent momentary steam flow spike. This resulted in a steam flow/feed flow mismatch with a concurrent 25% level in the No. 21 SG. Licensee investigation indicated the flow mismatch was caused by improper operation of a turbine stop valve while latching the turbine due to a sticky pilot valve in the stop valve operator. The licensee repaired the pilot valve and implemented a precaution to prohibit turbine latching while any low steam generator level alarms exist.)

On April 27, unit startup operations were again in progress, with all SG feedwater level control systems being monitored very closely. The generator was synchronized with the grid at 7:20 p.m. Feedwater level control systems for the No. 21, 22, and 24 SGs had been placed in automatic prior to synchronization.

In accordance with the previous recommendations, reactor power was increased utilizing the MS10 valves. At 7:23 p.m., when reactor power level reached 30%, the No. 23 SG feedwater level control system was placed in automatic. Level in the No. 23 SG rapidly increased, resulting in a turbine trip and reactor scram due to high-high level. The scram occurred before the level control system could be returned to manual.

Following this occurrence, it was recognized that the corrective actions taken following the trip on April 23 had not been successful in solving the level instability of the No. 23 SG. As a result, additional measures related to the entire SG feedwater level control system were ordered. These actions are as follows:

-- A complete channel calibration procedure was performed for the No. 23 SG process control system. The output of the valve demand controller (2FC500C) was found to be failed low. The controller would not integrate up, regardless of feed flow/steam flow mismatch and/or level error input signals. The controller was replaced, and the calibration procedure was satisfactorily completed.

-- Feedwater flow, steam flow and level recorders for all steam generators were calibrated. Valve 23BF40 was stroked; the stroke was satisfactory, and its operation was smooth. The No. 23 SG process control loop was fully instrumented for subsequent startup; this included feedwater flow and steam flow process input, feedwater flow/steam flow signal summator output, level error output, controller 2FC500C output, and 23BF40 valve position. Sensor calibrations were completed on the No. 23 SG feedwater flow (Channel 1 and Channel 2) transmitters. A blowdown of all SG feedwater flow transmitter sensing lines was performed. All lines were clear with the exception of the No. 23 SG Channel 2. The high side transmitter line had been plugged with rust buildup from the April 6 water hammer.

After reviewing the results of these investigations and corrective actions, it was concluded that the cause of the occurrence was the plugged high side sensing line of the No. 23 SG feedwater flow transmitter. The Station Operations Review Committee felt that the failed valve demand controller may have been a contributing factor, even though it was failed low when discovered, which would not have caused a high level situation. Unit startup was authorized, providing the level control systems were monitored closely for proper operation prior to turbine latching and generator synchronization, with additional test instrumentation installed.

During startup testing on April 28, it was suspected that the No. 23 SG feedwater flow nozzle (which provides the pressure drop for flow measurements used for indication, level control and protection signals) was not functioning properly, resulting in the inoperability of the feedwater flow channels. Radiography results, following controlled shutdown, revealed that the nozzle was located approximately 24 inches from its design location. The pins which hold the nozzle in place had apparently broken during the feedwater water hammer which had occurred on April 6, and the flow venturi broke free and moved 2 feet up the line.

In addition, investigation of the feedwater regulating bypass valve 23BF40 also indicated that the halves of the block connecting the actuator to the valve stem were not a matched set. The licensee concluded that this was probably causing an irregular stroke, observed after the scram on April 27.

The No. 23 feedwater flow nozzle was replaced with the No. 13 feedwater flow nozzle from Unit 1* (in a refueling outage). The feedflow transmitters associated with the No. 23 SG were calibrated, utilizing the new data associated with the replacement nozzle. A unit startup was begun on May 5, 1984. All SG water level control systems functioned as designed.

Following investigation by the Station Operations Review Committee (SORC) into the effectiveness of the post-scram review procedures for the April 23 and 27 events, it was determined that the procedures were adequate, and had identified a questionable feed flow indication following the April 23 scram. However, on April 23 this questionable indication had been attributed to inaccuracy of the strip chart recorders during low power operation. Following the scram on April 27, a review of the strip charts revealed the same indication.

Since reactor power level was at 30% prior to the scram, it was realized that the inaccuracy of the strip chart recorders during low power operation was no longer a plausible explanation. Although a plugged high sensing line of the No. 23 SG feed flow transmitter was the suspected cause, further testing was scheduled to confirm these suspicions. When subsequent testing revealed the malfunctioning feedwater flow channels, the unit was placed in hot standby, in accordance with technical specification requirements.

The licensee has issued a memorandum to all SORC members and alternates, and to those personnel involved in the post-scram review. The memorandum addressed the lessons learned from these events, with the intent of improving the overall quality of the post-scram review process. (Refs. 9-11.)

1.6 Reactor Shutdown Due To Inoperable HPCI System and Safety Relief Valve Failure

At Quad-Cities Unit 1** on March 5, 1984, a reactor shutdown was initiated due to the occurrence of two unrelated events. During performance of the monthly high pressure coolant injection (HPCI) pump operability surveillance, the pump lubricating oil was found to be contaminated with water. The surveillance was completed successfully, but HPCI was declared inoperable due to the contaminated oil. During testing of redundant safety systems, as required by technical specifications, an electromatic relief valve in the automatic depressurization system (ADS) failed to open when given a manual signal. The reactor was shut down in accordance with technical specifications. Since the unit was within two weeks of a scheduled refueling outage, the licensee decided to keep the plant shut down and begin the outage earlier than scheduled.

At 3:00 a.m. on March 5, the plant was operating at 88% power. After successfully completing the HPCI pump operability surveillance, a visual inspection of the HPCI pump was performed. The color of the lubricating oil indicated

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*Salem Unit 1 is a 1079 MWe (net) PWR located in New Jersey, 20 miles south of Wilmington, Delaware, and is operated by Public Service Electric and Gas.

**Quad-Cities Unit 1 is a 769 MWe (net) BWR located 20 miles northeast of Moline, Illinois, and is operated by Commonwecath Edison.

that water was present in the oil system. The HPCI system was declared inoperable at 5:20 a.m. due to the suspected water leak. Surveillance of the ADS, as well as core spray, low pressure coolant injection, and reactor core isolation cooling systems was immediately initiated as required by technical specifications. During the ADS surveillance, electromatic relief valve 1-203-3E failed to open on manual operation of the relief valves.

Although declared inoperable, the HPCI system was still capable of performing its intended function, and the four remaining relief valves provided sufficient depressurization capacity to fulfill the depressurization requirements. However, with the HPCI system declared inoperable and one electromatic relief valve taken out of service, technical specification requirements called for an orderly shutdown. On March 6, the reactor was manually scrammed at 2:06 a.m. according to procedure, and reactor pressure was brought to less than 90 psig by 4:50 a.m.

Licensee investigation showed that the presence of water in the HPCI pump oil system was caused by a leak in the pump's oil cooler system which allowed water to seep into the lubricating oil system of the pump. The water leaking into the system filled the oil sump and bearing housing to capacity, causing the fluid to leak out of the housing. The HPCI pump is a type DVMX, dual stage and is manufactured by the Byron Jackson company.

The failure of the electromatic relief valve was traced to a coil in the valve controller having become disconnected. Further investigation revealed that the vibration levels experienced by this valve during routine plant conditions caused the disconnection. The valve is a type 15245VS relief valve and is manufactured by Dresser Industries.

Corrective actions included replacing the HPCI pump oil cooler O-rings and gaskets with new replacement parts. The water side of the oil cooler was pressurized, and no leaks were found. This was the first occurrence of this type for this pump. For the 1-203-3E relief valve, the licensee has performed modifications to ensure a more positive connection in order to minimize any further effects of the local vibration levels. (Refs. 12 and 13.)

1.7 Blackout Caused by Incorrect Jumper Wire Connections

At McGuire* on April 20, 1984, personnel attempting to test the Unit 1 engineered safety features (ESF) actuation of Unit 2 nuclear service water nonessential header isolation valve 2RN-43A inadvertently tripped open the normal incoming circuit breaker to essential 4160 V switchgear 1ETA, deenergizing the bus. Diesel generator load sequencer 1A responded as designed; shedding loads from 1ETA, starting diesel generator (DG) 1A, closing the DG circuit breaker, and starting blackout loads that were available. (Unit 1 was in cold shutdown at the time of the event.) It was determined that a jumper wire had been attached to the wrong place in the circuit being tested, and had been independently verified as being correctly installed. Also contributing to the event were an erroneous procedure and misleading electrical elementary drawings (MCEEs).

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*McGuire Units 1 and 2 are each 1180 MWe (net) PWRs located 17 miles north of Charlotte, North Carolina, and are operated by Duke Power.

Due to a conflict in testing and maintenance schedules prior to the event, a procedure change had been written to cover testing of valve 2RN-43A. In order to isolate and test the valve, logic for seven other valves had to be modified by placing jumpers or by opening sliding links. Although the sliding links are shown on MCEEs, the representation is often schematically incorrect. For instance, the MCEE representation of the control circuit for valves 2RN-43A and ORN-12AC imply that relay CA contacts for ORN-12AC can be isolated without affecting the CA contacts for 2RN-43A by opening sliding link B13. In fact, opening B13 disables the logic for both valves. Properly identifying the wiring connections associated with these two valves, just on the part of the control circuits connected to CA, would require consulting four MCEEs, one connection diagram, and two wire tabulation drawings. This work was necessary to modify the circuit on only one of the seven valves that had to be disabled for the April 20 test of valve 2RN-43A.

Misrepresentation of sliding links on MCEEs was first discovered at McGuire in 1975. It was subsequently decided it was not feasible to revise the MCEEs, and that McGuire personnel would have to be trained to double check MCEE representation of sliding link applications against connection diagrams and wire tabulation drawings. The individual who wrote the ESF procedure change to test valve 2RN-43A was aware of the sliding link representation problems, and used the connection diagram to verify his method of isolating ORN-12AC. Since he thought he had confirmed the accuracy of the modification via the connection diagram, he did not consult the wire tabulation drawings. Due to the error, manual and electrical actuation of relay CA during previous attempts to test 2RN-43A on April 14, 18 and 19 had no effect on the valve. Trouble-shooting on April 17, 18, and 20 prior to the test was ineffective because the circuit modifications were removed after each test. The problem was discovered during review of the procedure following the event, and the procedure was revised.

On April 13, valve 2RN-43A failed to respond to the manual actuation of relay CA. At this time, it was thought that the actuation method might not be moving all of the relay switches properly. It was decided to actuate the relay electrically by jumpering from a terminal in the DG load sequencer 1A cabinet, which was known to be energized, to the coil of the relay (terminal C1). In order to prevent actuation of other relays connected to CA, the existing wire attached to CA was removed, and the jumper was attached to the terminal. CA was successfully actuated on April 18 and 19, although the test of 2RN-43A failed. On April 20, the jumper was accidentally installed on the lifted lead rather than on terminal C1 of relay CA. The second individual checked the placement of the jumper and thought it was properly connected. When the switch was closed, various relays actuated, one of which tripped open the normal incoming power circuit breaker, deenergizing 1ETA, and a blackout occurred. Diesel generator load sequencer 1A responded as designed. Operators returned offsite power to 1ETA by closing the normal incoming circuit breaker, and then shut down the DG and stopped unnecessary equipment.

The error in the verification of the jumper wire attachment was apparently caused by the following factors: the "verifier" had just verified that the lead had been lifted from the correct terminal; the jumper had been correctly installed twice before, giving the verifier confidence that it was correctly installed just prior to the event; the alligator clip attached to the lead was less than 1/2 inch from the terminal C1; and C1 and the alligator clip were obscured by the wires attached to other terminals on the relay.

The licensee reviewed the event with appropriate station personnel, stressing the following items:

-- Individuals should exercise particular care when modifying or verifying the modifications of systems, and should not be lulled into a false sense of security because the step has been done before.

-- Modifications of systems for testing must be researched to the extent that all possible consequences are known and understood. Technical reviews of procedures must be thorough and should be performed with the same source documents used for the preparation.

-- Personnel responsible for scheduling the testing activities should consider the manpower and added risks involved in separating components or parts of systems from the integrated test. The main effort should be directed toward having complete systems available at the scheduled test times. Problems in test scheduling should be identified early enough (long before outages) so that procedure revisions can be prepared and reviewed when adequate manpower is available. (Ref. 14.)

1.8 Loss of Both Standby Gas Treatment Systems

On April 19, 1984 at about 10:15 a.m., with reactor power at approximately 70%, a construction worker backed a bulldozer over a fire hydrant within the Cooper* restricted security area, causing a leak in the fire protection system. The system pressure dropped, causing both fire pumps to start automatically, sounding an alarm in the control room. Operators investigating the alarm found the hydrant sheared off and reported the event to the control room. At the direction of the Operations Supervisor, all fire pumps in service were secured until the fire hydrant was isolated at about 10:25 a.m, at which time system pressure stabilized at about 10 psig.

With the fire protection system jockey pump running, the system flushing pump was started in order to increase the rate of header repressurization. Later, the electric-driven fire pump was also started to further aid in header repressurization. Starting of the electric-driven pump resulted in a significant pressure surge. This pressure surge created a system water hammer which forced open the standby gas treatment system (SBGTS) deluge valve clappers, without tripping the automatic actuation alarm. At 10:34 a.m., the shift supervisor was informed by the control room personnel that the high moisture alarm had actuated in both trains of the SBGTS. The Operations Supervisor and Shift Supervisor inspected the SBGTS and found water leaking from the housing of both trains. At about 10:35 a.m., both trains were declared inoperable, thus placing the plant in a limiting condition of operation (LCO).

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*Cooper is a 764 MWe (net) BWR located 23 miles south of Nebraska City, Nebraska, and is operated by Nebraska Public Power District.

At 11:00 a.m., procedures were initiated for normal plant shutdown, and reactor power reduction was begun. Having entered a technical specification LCO requiring plant shutdown, the Shift Supervisor assumed the duty of Emergency Director and declared a Notification of Unusual Event. The basis for declaring the SBGTS inoperable is that wetting of the charcoal filters in both trains of the SBGTS removed the iodine absorbing capability of the charcoal, which prevented the SBGTS from performing its intended safety functions.

At 2:00 p.m., with reactor power at approximately 34%, the reactor was manually scrammed. Hot shutdown conditions were established, and an orderly cooldown of the reactor was commenced to place the reactor in cold shutdown. At 10:15 p.m., while the residual heat removal system was in the shutdown cooling mode, reactor coolant temperature was less than 212°F. About 10 minutes later, the vessel head vents were opened, establishing cold shutdown conditions. Thus, as required by technical specifications, plant conditions were established which did not require the SBGTS to be operable.

Immediately after declaring the SBGTS inoperable, steps were taken to acquire new charcoal filters to replace the damaged sets. The new charcoal filters arrived on April 20. Diocryl phthalate and freon tests were completed, and the system was returned to an operable condition. The SBGTS had been inoperable for a total of 31.5 hours.

Corrective actions also included disassembly and examination of the deluge clappers, which were found to have excessive wear on the latch tabs. This wear reduced the force necessary to push the clapper past the latch assembly without tripping the latch. The clappers were replaced and it was decided to maintain the deluge system in an isolated condition. In the event of a fire in the SBGTS, the revised station operating procedures direct an operator to manually open the deluge system valve. Longer term actions include an engineering evaluation of the SBGT automatic deluge system and a review of procedures for controlling the activities on construction contractors.

The Cooper fire protection system utilizes one electric- and one diesel-driven pump in parallel, each rated at 3000 GPM. A small capacity jockey pump maintains header pressure at approximately 120 psig to 140 psig. When header pressure drops to 110 psig, the electric-driven pump will automatically start. If header pressure continues to drop to 105 psig, the diesel-driven pump will automatically start. To avoid the water hammer transient, the main fire pumps should not have been placed into service after the hydrant was isolated (i.e., after isolating the leak). Instead, the fire protection system jockey pump alone should have been utilized to restore the system to full pressure at a gradual, rather than sudden rate. (Refs. 15-17.)

1.9 Synopsis of Cold Weather Events During Winter of 1983-1984

During the winter of 1983-1984, many nuclear plants were affected by the record cold weather throughout the country. Although there were relatively few cold weather induced problems with safety-related instruments and instrument sensing lines, which suggests licensee cognizance of the necessity for cold weather protection, the number and repetitive nature of nonsafety-related instrumentation problems imply that licensees have not implemented an equivalent degree of survellance to the balance of the plant. A synopsis of such events, complied from the NRC Headquarters Daily Report for the winter months of 1983-1984, is provided below.

UNIT	DATE	DESCRIPTION OF EVENT
Farley 1 & 2	12/24/83	The fire protection system water supply decreased below the 250.000 gallon technical specification limit because of a frozen supply valve. Also, several sprinkler heads froze and cracked. Cause attributed to personnel error.
Surry 1	12/24/83	The unit tripped from 100% power when a feedwater flow instrumentation line froze, then thawed, and gave a full open signal to the feedwater regulating valve. A portion of the sensing line is located in the technical support center, which is under construction and open to the environment. This sensing line is heat traced and insulated. Construction personnel needed an additional source of power and unplugged the heat tracing. Licensee subsequently restored power to the heat tracing and the line thawed. Unit 2 was not affected by this event, nor was safety equipment at either unit. Heat tracing is now checked each shift.
Arkansas 2	12/25/83	With the unit in cold shutdown, during investigation of a frozen level transmitter for the RWST, the licensee inadvertently vented both the frozen transmitter and a functional RWST transmitter. This caused a low RWST level signal and initiated a recirculation actuation signal. In December 1980 all four RWST liquid level transmitters froze because the system heat tracing circuit was deenergized. In the past there have been at least five other events of RWST instrumentation failure due to freezing.
Dresden 2	12/25/83	The reactor tripped from 45% power due to frozen, ruptured pressure instrument lines thawing and causing the two operating feedwater pumps to trip. The event began when the licensee noted the lake was beginning to freeze and brought a truck inside through the turbine trackway door in preparation to assembling a crew to prevent the freezing problem. However, the turbine trackway door stuck open and could not be closed for 1.5 hours. During this time, the instrument lines froze and ruptured. When they thawed after the turbine trackway door was closed the pressure bled off through the rupture,

UNIT	DATE	DESCRIPTION OF EVENT
Dresden 2 (continued)		causing a reactor feed pump low suction pressure indication. The reactor trip occurred concurrent with the thawing of the instrument line. The event did not affect safety systems at Unit 2 and could not affect Unit 3.
Peach Bottom 2 & 3	12/25/83	Both units were manually tripped when the intake structure became clogged with rapidly forming ice. Unit 2 lost suction to all of its circulating water pumps before the manual trip and Unit 3 was approaching this condition. Normally, ice formation can be delayed by an air bubbler system or broken-up easily by crane and wrecking ball. The sudden severity of the weather prevented anticipatory initiation of the air bubblers, and because of the Christmas holiday, a qualified crane operator was not on duty. Both units shut down normally and condenser vacuum was maintained.
Oconee 1	2/25/83	With the unit at 100% power, the BWST level channel 1 failed low when moisture in the instrument air lines froze, thus giving incorrect level indications. Redundant level channel 2 was operable. Strip heaters that heat the transmitter box housing were deenergized due to a tripped panelboard breaker. The cause of the tripped panelboard breaker is unknown. A similar incident occurred on March 3, 1980. (Note: This event was reported as LER 82-21).
Salem 1 & 2	12/25/83 12/26/83 12/29/83	The fire suppression stored water volume fell below the technical specification limit of 300,000 gallons in each of two tanks. Each event occurred when the automakeup pump sensors froze and the system was drawn down when the fire pumps started. Also, on December 25, a fire suppression line leaked and froze after a deluge valve body cracked.
Crystal River 3	12/26/83	The severity of the winter weather caused the Gulf of Mexico to cool 9°F in approximately 60 hours. The rapid change in water temperature caused an excessive fish kill and a large amount of dead fish appeared on the inlet water screen. The decreased water flow available to the condenser required a reduction in power and the main generator was disconnected from the grid.

UNIT	DATE	DESCRIPTION OF EVENT
Quad Cities 1	12/28/83	The reactor building main chimney radiation stack monitor froze. Plant releases were monitored by other sensors. The faulty heat tracing was replaced.
Quad Cities 2	1/2/84	A padlock could not be tested because it was frozen. A guard, making his normal rounds, noticed the padlock was no longer frozen, checked it and found that it was not locked.

1.10 References

(1.1) 1. Public Service Gas and Electric, Docket 50-311, Licensee Event Report 84-06, April 17, 1984.

2. NRC, Region I Inspection Report 84-15 for Dockets 50-272 and 50-311, June 5, 1984.

(1.2) 3. Portland General Electric, Docket 50-344, Licensee Event Report 84-06, May 25, 1984.

(1.3) 4. Letter to J. B. Martin, NRC/RGN-V, from R. J. Rodriguez, Sacramento Municipal Utility District, forwarding Licensee Event Report 84-15, April 18, 1984.

5. NRC, Region V Inspection Report 84-07 for Docket 50-312, June 4, 1984.

(1.4) 6. NRC, PNC-III-84-21 (March 2, 1984) and -21A (March 5, 1984).

7. Letter to J. G. Keppler, NRC/RGN-III, from R. P. Crouse, Toledo Edison, March 6, 1984.

8. Toledo Edison, Docket 50-346, Licensee Event Report 84-03, March 30, 1984.

(1.5) 9. NRC, Preliminary Notification PNO-I-84-31, April 9, 1984.

10. NRC, Region I Inspection Report 84-15 for Dockets 50-272 and 50-311, June 5, 1984.

11. Public Service Gas and Electric, Docket 50-311, Licensee Event Report 80-10, May 23, 1984.

(1.6) 12. NRC, Preliminary Notification PNO-III-84-23, March 6, 1984.

13. Commonwealth Edison, Docket 50-254, Licensee Event Report 84-01, March 26, 1984.

(1.7) 14. Duke Power, Docket 50-369, Licensee Event Report 84-14, May 21, 1984.

(1.8) 15. NRC, Preliminary Notification PNO-IV-84-06, April 19, 1984.

16. Letter to J. T. Collins, NRC/RGN-IV, from P. V. Thomason, Nebraska Public Power District, April 24, 1984.

17. Nebraska Public Power District, Docket 50-298, Licensee Event Report 84-07, May 18, 1984.

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. There has been minimal effort to edit the text provided, since it is assumed that the LER descriptions are accurate and complete, as required by 10 CFR 50.73(b).

Because the purpose of this section is to objectively highlight the information selected, event dates and plants involved are not included in the abstracts. Persons interested in the plant docket number and LER number may obtain this information by contacting the Editor on 301-492-4499, or at U. S. Nuclear Regulatory Commission, EWS-263A, Washington, DC 20555.

2.1 Intermediate Range Monitor Dry Tube Cracking (Docket 50-219/LER 84-08)

While performing local power range monitor (LPRM) replacement work during the current refueling/maintenance outage at a BWR (General Electric), operations personnel visually noticed that the dry tube associated with intermediate range monitor (IRM) 12 appeared to be bent near the upper core grid. An underwater TV camera inspection performed on the dry tube showed a significant amount of cracking in the top portion of the tube.

A review of the videotapes revealed that seven IRM and one SRM dry tubes were cracked seriously enough to be considered fractured. There are a total of eight IRM and four SRM tubes in the vessel. The cracks were found in the thin wall tube surrounding the compression spring which facilitates installation, location, and removal of the dry tubes by ensuring engagement of an upper plunger with a pocket in the intersection of top guide plates. This is a non-pressure retaining portion of the dry tube and all cracks were in the vicinity of non-stress relieved welds. The two most severe cracks occurred in the uppermost pressure boundary welds which prevent reactor coolant from intruding into the tube housing the neutron detector. No major indications were observed in the adaptor, the shaft, the guide plug, the primary pressure boundary or any other portion of the tube.

Although the exact cause of this failure cannot be determined at this time, the following factor(s) could have contributed to this occurrence:

(1) Flow induced vibration/damage from running the recirculation or shutdown cooling pumps when fuel has been removed from around the dry tubes.

(2) Radiation enhanced embrittlement of stainless steel.

(3) Stress corrosion cracking of the weld sensitized metal. The welds produced during fabrication of the dry tubes are not in a stress-relieved or solution-annealed condition.

The following analysis is presented:

(1) The fractured dry tubes have severely reduced ability to return to straightness if deflected, and therefore pose a risk during fuel handling. This is sufficient reason to remove these units immediately.

(2) The clearances around the dry tubes in the loaded core are sufficiently close to preclude large loose parts migration. Small loose parts constitute a minimal risk.

(3) Cracks propagating into the pressure boundary would confront compressive stresses that would arrest their growth.

(4) Cracking is likely to become more extensive with time.

(5) There is a distinct possibility of tube failure during normal operation and consequent channel damage with the potential for fuel clad dammage.

(6) The dry tubes can continue to function even with a maximum offset of dry tubes following a 360° through wall crack, because the two pieces will be held in functional alignment by support from adjacent fuel channels. Also, the support provided by fuel assemblies will prevent adverse safety consequences from loose pieces in the event a dry tube becomes completely severed.

The cracks found in the SRM/IRM dry tubes did not breach the primary coolant pressure boundary nor did they cause their associated neutron detectors to lose function. With the plant in its current REFUEL mode, the safety consequence is minimal. With the reactor at power there is a potential for a tube break at the pressure boundary causing a small break LOCA within the drywell.

2.2 Rod Cluster Control Assembly Wear (Docket 50-305/LER 84-03)

During a refueling shutdown at a PWR (Westinghouse), plant personnel visually inspected three of 29 rod cluster control assemblies (RCCAs) for evidence of cladding wear. The inspection was prompted by the recent inspections of RCCAs at other nuclear facilities which revealed cladding wear greater than expected. The RCCAs are of the spider mounted design which contain 16 rodlets per RCCA. The assemblies are compatible with the 14 x 14 fuel design and contain silver, indium, and cadmium as absorber material.

The inspection was performed using an underwater TV camera coupled with videotape recording equipment. The results were recorded on five videotapes and revealed apparent wear marks on the surfaces of the RCCA absorber rodlets. The wear marks are about 1 inch in length and are located at an elevation which corresponds to the guide cards used to position the rodlets in the guide housing when the RCCAs are fully withdrawn (at 228 steps) from the core. The wear is postulated to occur as a result of the vibratory interaction (fretting) between the rodlets and the guide cards during long periods of steady state power operation. This fretting is characteristic of the design of the guide cards.

Based on a detailed review of the videotapes, Westinghouse has concluded that none of the inspected RCCAs exhibit wear in excess of the Westinghouse wear criteria and that the RCCAs are therefore acceptable for operation in the upcoming cycle.

Westinghouse has also suggested that by changing the normally parked position of all the RCCAs by 2-3 steps, fretting in existing areas can be minimized and the lifetime of the RCCAs could be extended.

2.3 Thunderstorm Causes Reactor Scram (Docket 50-364/LER 84-04)

During steady state operation at a PWR (Westinghouse) with the unit at 100% power and severe thunderstorms in the area, several lightning strikes occurred on the plant site. A voltage surge was experienced which tripped both the primary and backup 25 V dc power supplies to all four rod control power cabinets. This resulted in all control rods dropping into the core resulting in a power range neutron high flux negative rate condition. The reactor trip breakers opened due to this signal.

The lightning caused a voltage surge in the plant's ac distribution system. The resulting voltage spike caused the overvoltage protection devices to trip the primary dc power supplies which are powered from the ac distribution system. Due to the close proximity of the primary and backup power supply cables, it is thought that capacitive coupling caused the overvoltage protection devices to trip the backup power supplies which are powered from the motor-generator sets. The power supplies were reset and a normal startup was conducted.

2.4 Improper Capacitor in an NNI Power Supply Results in a Reactor Trip (Docket 50-302/84-10)

The PWR (Babcock & Wilcox) was operating at 97% reactor power when the NNI-Y power supply failed which caused erroneous signals to be input to the integrated contol system (ICS). The ICS responded by reducing main feedwater flow to the B steam generator and hence heat removal from the reactor coolant system. This resulted in an automatic reactor trip on high reactor coolant system pressure. The NNI-Y failure was due to a shorted high frequency filter capacitor in the 120 V ac input to the +24 V dc power supply (Lambda Electronics Corporation Model LM-E24). The failed capacitor was found to have incorrect voltage and capacitance ratings. The incorrect capacitor was installed by the manufacturer.

2.5 Potential Failure of the Standby Gas Treatment System (Docket 50-277/LER 84-08)

Unit 2 (General Electric BWR) was operating at 80% power coasting down to begin an outage. At 6:00 p.m., the A fan of the standby gas treatment (SBGT) system was manually started to commence the drywell deinerting; however, no flow was achieved using the A fan because both the inlet and outlet dampers failed to open.

The SBGT system consists of an A and a B filter assembly, and three fans, A, B, and C, ducted into parallel to the filter assemblies. The A fan is utilized for Unit 2, with B as a standby, and the C fan is utilized for Unit 3 (BWR) with the B fan as a standby.

As a result of an investigation into the consequences of the failure, it was determined that the potential existed for a single failure to have prevented the fulfillment of the safety function of the SBGT system.

If, on the date of the occurrence, a Group III isolation had occurred on Unit 2, the A SBGT system fan would have started automatically, but there would have been no flow and the B SBGT system fan would not have received a low A fan differential pressure signal to start due to the orientation of the differential pressure switch sensing lines.

The high and low sensing taps of the differential pressure switch are piped between the dampers to the inlet and outlet of the A fan to prove flow. With the dampers closed and the fan running, the switch would have sensed a differential pressure preventing the B fan from automatically starting.

The inlet and outlet dampers on the SBGT system fans are actuated by pneumatic operators. Each fan has a 120 V ac 3-way Asco solenoid valve (Catalog Number HT8320A83) which is normally energized, and wired into the fan control circuit. When the SBGT system is actuated, the solenoids pass a pneumatic signal to open the inlet and outlet dampers. When the A fan was manually started, solenoid valve SV-0009 failed to operate, and the dampers remained closed.

The standby start differential pressure switches on the A and C fans will be replaced with a flow sensor using a duct pitot tube. An engineering evaluation is being performed to determine optimum positioning of the sensors in the SBGT system ductwork to ensure proper flow sensing.

Until such time that the solenoid failure analysis and flow sensor modification are completed, a daily routine test of the operability of the SBGT system fans inlet and outlet dampers will be performed.

2.6 Wetting of SBGTS Charcoal Filters (Docket 50-397/LER 84-26)

The activation of pre-action and deluge portions of the fire protection system at a BWR (General Electric) have been causing pressure surges in the fire protection system. The surges have been of sufficient magnitude to unseat the standby gas treatment system (SBGTS) deluge valves. The SBGTS deluge valves automatically reseat because their trip mechanisms have not been activated, however, the water found in the SBGTS indicates that the pressure surge is unseating the SBGTS deluge valves for a short duration.

1st Event

An ionization detector in the cable spreading room was activated by craft using a grinder. The detector activated Pre-Action System 65 (cable spreading room) by tripping the respective deluge valve. The resulting pressure drop caused the fire pumps FP-P-2A and FP-P-2B (2000 gpm electrics) to start. The ensuing pressure surge caused Pre-Action System 84 (HPCS diesel room) to flood its piping (no water issued from nozzles). The standby gas treatment deluge valve for Train A prefilter momentarily lifted, wetting the prefilter medium. The standby gas treatment Train B second charcoal bed deluge valve lifted momentarily and failed to reset properly; water leaked by the seat and ran out the nozzles onto the floor adjacent to the charcoal bed. No water came in contact with the charcoal in the unit.

Operations isolated the deluge valve for Train B second charcoal bed and it was then reset. The prefilter was dried and the water was cleaned up in the Train B charcoal bed area. The trains were tested using the iodine method and found satisfactory, then placed in service. Pre-Action Systems 65 and 84 were drained and returned to service. Fire pump start pressure (mercoid pressure switches) were checked. A plant modification request was written to investigate the feasibility of installing pressure surge reducing valves (Clayton type) to mitigate the surge during pump starts. The event posed no potential safety problem.

2nd Event

Water was found in the area of the second charcoal filter of SBGTS Train B. Activation of the cable chase pre-action system the previous week had initiated the same sequence of events described in 1st Event. The SBGTS was again cleaned up and a test canister pulled and analyzed to insure no damage to the charcoal.

An inspection was made immediately after activation of the fire protection system and water was again found in the charcoal filter area. The sequence described in the 1st Event was repeated again. The SBGTS was again cleaned up and a test canister pulled and analyzed to insure no damage to the charcoal.

The 1st Event resulted in the initiation of a plant modificaton request which has subsequently been processed and the surge reducing valves are being procured and will be installed as soon as possible. The fire protection system pumps are being run continuously to prevent additional surges.

2.7 Loss of Main Annunciator Panels Due to Maintenance Error (Docket 50-275/LER 84-12)

With the PWR (Westinghouse) in hot standby, an I&C technician performing maintenance on the control room main annunciator typewriter misread the procedure he was following and opened the ac and dc power supply breakers for the main annunciator panels. Control Room Operators observed the loss of annunciator panel indication and, because they were aware of maintenance being performed on the annunciator typewriter, quickly assessed the problem and instructed the I&C technician to reclose the main annunciator power supply breakers. Power was restored in the main annunciator within two minutes.

The main annunciator is provided with a redundant power supply. In the case of failure of one power supply, the system automatically transfers to the backup power supply and activates the "MAIN ANNUNCIATOR" alarm through the undervoltage relays. However, with the ac and dc power supply breakers open, this design feature was bypassed.

The I&C department head has instructed his supervisors to reemphasize to their technicians the importance of reviewing and understanding procedures prior to performing them. In addition, the I&C department head has issued a policy directive requiring two technicians to perform work on safety-related or important to safety equipment whenever the assigned technician is not thoroughly familiar with the procedure to be used or the equipment to be worked on. Work assignments for all shifts, including backshifts and weekends, are made when I&C supervisors are available to discuss job tasks with technicians and to determine whether or not two technicians are required to perform the work.

2.8 Automatic Isolation Caused by Portable Radio Transmissions (Docket 50-416/LER 84-17)

April 9, 1984, at 1620 hours, the containment isolation valves for the reactor (General Electric BWR) water cleanup system (RWCU) isolated on a heat exchanger room high temperature signal. Operators immediately checked the room temperature and found it normal. Maintenance personnel found no problems with the circuitry for the devices which caused the isolation.

The cause of the isolation is believed to be from a portable radio transmission in the upper control room. A sign on the entrance door which prohibited radio transmission in the area was found missing, which may have contributed to this event. The area was immediately re-posted placing the room off limits to use of radios. Permanent type warning signs are being installed in areas which prohibit portable radio transmissions to prevent their unauthorized removal.

2.9 Inoperable ECCS (Docket 50-275/LER 84-13)

On April 7, 1984, while the PWR (Westinghouse) was in hot standby, it was discovered that both sybsystems of the emergency core cooling system (ECCS) had been inoperable for 14 hours, 20 minutes. This condition was in noncompliance with two technical specification sections.

On April 6, 1984 the plant experienced an anticipated safety injection as part of steam generator safety valve startup testing. The safety injection resulted in the discharge of the contents of the boron injection tank (BIT) into the reactor coolant system. To recharge the BIT with 12% boric acid solution, licensed operators, using approved procedures, inhibited the automatic opening feature of the BIT inlet and outlet valves during the recharging operation. This practice prevents problems which might occur due to an inadvertent safety injecton signal while the BIT is being drained prior to recharging with boric acid. With the BIT inlet and outlet valves disabled, there is no ECCS flowpath from the charging pumps through the BIT to the reactor coolant system. Operations personnel were concentrating on restoring the BIT and did not consider the requirement of the ECCS technical specification. Additionally, the approved operating procedure did not provide any technical specification guidance to the operators that two sections of technical specifications were involved.

After completion of recharging the BIT with 12% boric acid solution, and upon discovery of this condition, the BIT inlet and outlet valves were made operable and the system was returned to operable status.

2.10 Degraded Surge Capacitor Causes a Reactor Trip (Docket 50-318/LER 84-03)

While the PWR (Combustion Engineering) was operating at 100% power, an automatic reactor trip occurred due to a reactor protective system "lo-flow" signal. The turbine tripped on "reactor trip bus low voltage" as expected. The "lo-flow" signal was generated from the loss of reactor coolant pump (RCP) 22B. The power supply breaker for RCP 22B had opened. Opening of the breaker could be the result of either the differential or overcurrent relays tripping. In this instance, both relays were found tripped. Investigation determined that the root cause of this event was an overcurrent condition resulting from an internal short to ground in one of three surge capacitors installed for RCP 22B. The failed surge capacitor was disconnected and the pump returned to service.

A surge capacitor is installed in each of the three phases of each RCP. These capacitors are installed to protect the reactor coolant pump motors from high voltage surges which could be present on the electric supply buses during certain switching operations. The failed surge capacitor was a Westinghouse style "C". Investigation following disassembly discovered an internal electric short to ground had occurred resulting in an overcurrent condition. This plant experienced a similar event in June 1983 when a surge capacitor failure on RCP 11A resulted in a reactor trip. Westinghouse representatives assisted in the inspection of the three surge capacitors on RCP 11A. That inspection revealed an internal short to ground in the failed surge capacitor, and capacitance degradation in the other two surge capacitors. According to Westinghouse, the visual examination and subsequent capacitance measurements could not determine why the capacitor had failed.

Based on Westinghouse's recommendations, the following corrective actions were planned for both Unit 1 and 2:

(1) Replace older surge capacitors with new surge capacitors, when possible. (Unit 1 - completed, Unit 2 - scheduled for spring 1984 outage)

(2) Conduct capacitor degradation checks each refueling outage (Unit 1 - completed, Unit 2 scheduled for spring 1984 outage)

(3) Replace all surge capacitors every 4.5 years.

2.11 Redundant Power Supplies Supplied by a Single Breaker (Docket 50-370/LER 84-11)

At a PWR (Westinghouse), control room annunciator "Process Control System Power Supply Failure Protection Cabinet I" alarmed and status alarms indicated a loss of channel 1, which was being used for steam generator and pressurizer control. All four steam generator (S/G) levels began increasing because the four feedwater regulator valves opened. The Control Operators placed the four S/G level controls into MANUAL. One Control Operator made adjustments with the level controllers to decrease levels in S/Gs A and B. Another Control Operator was ensuring that the controls were changed from channel 1 to channel 2. Then he began to make level adjustments on S/Gs C and D. The adjustments on S/Gs C and D were not made in time, which allowed S/G D to reach the hi-hi level turbine trip setpoint of 82% at 0100. Unit 2 was in Mode 1, at 100% power, at the time of the turbine/reactor trip.

This event is attributed to component failure due to the failure of the main power supply in the process control system (PCS) protection cabinet I. Design deficiency also contributed to the event because power to both the main and backup power supplies in each protection cabinet is supplied by one supply breaker for each cabinet.

Each protection cabinet is powered by a main 26.0 V power supply (P/S). A backup 24.0 V power supply automatically provides power to the cabinet in the event the main power supply fails. Both power supplies in each protection cabinet are supplied by the same supply breaker, but the power supplies in each control cabinet are supplied by different supply breakers. Each power supply has a 35 ampere breaker and a 30 ampere fuse on the input with a 70 ampere breaker on the output. The Unit 2 protection cabinet I supply breaker is rated at 20 amperes.

Troubleshooting determined the main power supply was drawing excessive current (26.8 amperes) which tripped the 20 ampere supply breaker, but was not enough to open the 30 ampere fuse or open the 35 ampere breaker in the cabinet. The supply breaker trip resulted in a loss of both power supplies, which caused a loss of protection channel 1. The system transients resulted in a S/G D hi-hi level trip two minutes after the power supply failed. The defective main power supply (North Electric Part No. PEC 3569) was removed from the protection cabinet I and a spare was installed. It was satisfactorily tested and placed back in service. Modifications will be implemented on Units 1 and 2 to place the backup power supplies for protection cabinets I, II, III, and IV on separate supply breakers. This will prevent deenergizing both power supplies if one supply breaker trips.

This was the fifth power supply failure in the PCS during the last five years (out of 32 power supplies on both units). The failures were caused by an open in the secondary winding of a transformer. This failure was the first resultig in a reactor trip. This was the first failure where the power supply did not disconnect itself by opening the 30 ampere fuse in the cabinet or by an open in the secondary of the transformer. The number of power supply failures is being investigated by Westinghouse to determine the cause and if other Westinghouse plants are experiencing similar power supply failures.

2.12 Operator Distraction Leads to a Reactor Scram (Docket 50-331/LER 84-15)

While the BWR (General Electric) was in the startup mode, the unit experienced a reactor scram due to an intermediate range monitor (IRM) upscale trip. Neutron flux at the time was being monitored on the source range monitors (SRMs) and on IRM Range 1 with reactor power at less than .001% rated. The reactor coolant pressure was approximately 100 psi prior to the scram. The reactor had been brought to 400 psi several hours earlier to perform a startup inspection for leakage. The cause of the scram was an operator error in recognizing the positive reactor period (approximately 20 seconds), and consequently failing to select higher IRM scales.

In accordance with plant procedures, a post-scram review of the event and applicable plant parameters before, during, and after the scram, was conducted prior to resuming reactor startup. During the course of the review, it was determined that the operator was momentarily distracted from the IRMs due to observing and diagnosing a two rod insert error which had occurred earlier when the reactor was being driven critical following the 400 psi reactor pressure drywell inspection. This error had left two control rods inserted one notch greater than that specified in the control rod pull sequence sheets (as designed, the rod worth minimizer system requires three "insert" errors to initiate a rod block). The operator had resumed rod pulls two steps later than the specified control rod pattern (pull sheets). Although this distraction warranted his prompt attention, it should not have been of a magnitude to have caused the operator's failure to observe the increasing IRM (and SRM) flux levels. Consequently, appropriate disciplinary action was taken for the involved reactor operator. In addition to this, the training department has been made aware of the situation and its consequences and shall instruct other operators accordingly during requalification training.

2.13 Improperly Coordinated Maintenance Activities Produce a Reactor Scram (Docket 50-348/LER 84-12)

The PWR (Westinghouse) was in hot standby with surveillance testing in progress following the refueling outage. As part of this program, I&C personnel were performing the turbine trip - reactor trip response time test. In accordance with the procedure, a B train P-9 signal (reactor power greater than 35%) existed on power range channel N-41. At 1133, other I&C personnel began performing the Nuclear Instrumentation System Power Channel N-42 Calibration and Functional Test which involves generating A and B train P-9 signals on power range channel N-42. When this was done a B train reactor trip signal occurred due to a P-9 signal on 2 out of 4 power range channels while the turbine was tripped.

Since only a B train reactor trip signal was generated, only the B train reactor trip breaker opened. The plant operator immediately tripped the A train reactor trip breaker manually. This event had no effect on the unit nor did it cause any control rod movement because the unit was in hot standby with all control rods fully inserted.

This event was caused by personnel error. The I&C personnel performing the tests failed to ensure that no other power range channels were in test prior to commencing work, as required in the initial conditions section of the procedure. The personnel involved have been counseled concerning the necessity of adherence to procedures.

2.14 HPCI Inoperable Due To Failure To Reset Bypass (Docket 50-271/LER 84-05)

On April 20, 1984, during normal operation with the BWR (General Electric) operating at 100% power, the operators were performing monthly high pressure coolant injection (HPCI) valve operability testing. Upon starting the auxiliary oil pump, it was observed that the trip throttle valve did not open. A second attempt was made with the same results. The SCRO then pushed the HPCI high water level reset and the valve went open. During a subsequent review of the event, it was determined that a problem had existed with the high drywell initiation of the HPCI system during the time from the last trip on April 16, 1984, and the time the reset button was pushed. The auto start on low reactor water level was fully operable during the entire period.

During the scram on April 16, 1984, the reactor scrammed on high steam flow due to main steam isolation valve (MSIV) closure. The reactor water level increased to a point at which a high level shutdown would have occurred had the system been operating. This high level shutdown bypasses the high drywell pressure initiation signal to prevent the system cycling around the high level setpoint during an accident. The high level shutdown is annunciated; however, this annunciator will clear when the level decreases below the high level setpoint while the bypass around the high drywell pressure initiation must be manually reset.

The reactor remained in hot standby until startup some 13 hours later. By remaining in hot standby it was assumed that all systems were operable. This was substantiated by the fact that no alarms were present. The startup procedure does instruct the operator to reset all reset buttons. However, there is no individual sign off for each reset button. Since the HPCI system had not been called upon to operate during the trip, the operators overlooked the manual reset of the high level shutdown.

To prevent a recurrence of this event, additional steps will be added to the final conditions of the scram procedure. These final conditions will insure all reset buttons as listed in the startup procedure have been reset. In addition, the startup procedure will have a check-off sheet added to document that each reset button has been reset.

2.15 Load Shedding Design Problems (Docket 50-335/LER 84-01)

The undervoltage relaying in the 480V switchgear at this PWR (Combustion Engineering) is used to shed the connected load on the 480V bus and start the emergency diesel generators on detection of loss of normal ac power.

The emergency diesel generators will start when either of the following conditions arise:

(1) Loss of offsite power

(2) Receipt of a containment isolation signal, safety injection actuation signal, or containment spray actuation signal.

In scenario (1) above, the diesel generators will start and after attaining rated speed and voltage (approximately 10 seconds after receipt of a start signal), the breaker will close and emergency loads will be sequentially connected.

In scenario (2), the diesel generator will start but will not connect to the bus unless a loss of offsite power or sustained undervoltage signal is generated. If loss of offsite power or sustained undervoltage occurs, the breaker will immediately close and sequential loading will start. In either case, load shedding must occur prior to closing of the diesel generator breaker.

The load shedding scheme presently employed has a time delay of 8 seconds prior to actuation. This time delay is used to prevent spurious trips of the 480V busses. In scenario (1) above, the diesel generators require 10 seconds from startup to breaker closing, therefore even with the 8-second delay, load will be shed before breaker closing occurs. However, in scenario 2, the diesel generators are already running when loss of offsite power occurs, thus breaker closing is immediate and load shedding will not occur due to the built-in 8-second delay.

It is intended to bypass the 8-second time delay during loss of offsite power condition and thus allow proper load shedding during all postulated scenarios. This has been accomplished by implementation of a plant change/modification.

2.16 Maintenance on a Valve that Could Not Be Isolated from the Reactor Vessel (Docket 50-387/LER 84-18)

During the performance of the "Recirculation Pump Discharge and Bypass Valve Operability Test" prior to Unit 1 (General Electric BWR) restart, recirculation discharge valve 1F031B failed to operate. This valve would be required to close should low pressure coolant injection or Loop B residual heat removal operation be needed. Unit 1 was cooled down and the valve was disassembled.

Special care was taken during disassembly to prevent leakage since there is no isolation between the valve and the reactor vessel. A special procedure was written to perform the work. Valve disassembly was begun by cycling the valve to the closed position and carefully opening the valve's drain and vent lines; no leakage from the drain valve verified the valve to be seated in the closed position. After removal of the valve packing, a valve stem locking device was placed around the valve's stem and jacked up against the valve's yoke. In addition, a stem jacking rig was then placed atop the valve's stem to prevent any upward movement of the disc. With the stem locking device and jacking rig securely mounted, the valve's actuator (mounted atop the valve yoke) was removed. Four valve body to bonnet studs were removed and replaced with four long B7 studs. The valve stem locking device was then repositioned with the jacking bolts removed. Two crossmembers were placed across the stem clamp and attached to the B7 long bolts. All but two bonnet nuts and studs were then removed. The last two nuts were loosened and the bonnet with the yoke attached was slowly raised approximately an inch in order to determine any leakage. With no leakage evident, the remaining two nuts were removed. The valve bonnet was then raised high enough to allow access to install a disc locking device within the valve's body, over which a locking device top plate was placed and securely bolted to the valve body.

With the disc locking device installed, both the stem clamp and the stem jacking rig were removed allowing removal of the valve yoke, packing glands and finally the valve's stem. Following inspection, the valve was reassembled using a new stem, in a manner reverse to that described above.

Inspection showed that valve 1F031B's stem was contacting the upper and intermediate packing glands when stroked causing the development of a metal burr or gall point on the stem. Additional valve motion led to binding of the valve.

The valve vendor was contacted and more detailed direction for proper adjustment of the packing glands was obtained; specifically, during reinstallation of the valve's packing glands, measurements were made to assure the glands were not cocked during draw down (i.e., the tightening of the gland jam nuts). The vendor also recommended that the inner diameters of the upper and intermediate packing glands be increased by .042 and .028 inches respectively prior to valve reassembly.

During post maintenance testing, a scratch and gall mark was found on the new stem for valve 1F031B. Additional stroking continued to worsen the condition; the valve however, did not bind. The valves packing glands were raised. The valve stem, packing glands and back seat were inspected. Contact between the stainless steel stem and stainless steel glands initiated the scratch on the stem. All raised metal was removed.

Investigation revealed that the tolerances between the valve's stem and gland, even after assuring the glands were straight, allowed sufficient lateral movement of the gland in its stuffing box to permit contact between the stem and gland.

The maintenance work plan was revised to require feeler gauge checks around the valve stem after installation of the upper and intermediate packing glands to ensure adequate clearance between the valve stem and packing glands.

Dimensional checks on the gap between the valve stem and back seat; the valve stem and stuffing box showed the back seat bushing to be slightly offset with respect to the bore for the lower stuffing box. This offset causes the valve stem to ride very close to one of the back seat bushing and come in contact with one sde of the back seat during valve motion. Indications are that galling of the stem did not result from the stem's contact with the stelite back seat but that the back seat accelerated any galling once it was initiated.

Although the actions identified reduce the possibility of galling the valve stem, factors inherent in the valve's design tend to increase the potential for such an occurrence. Specifically, those factors are:

(1) The tight clearances between the valve's stem and its packing glands; the stem, prior to boring the glands, was approximately 2.751 ±0.005 inches in diameter with an opening of 2.771 ±0.005 inches between the packing glands; allowing approximately .01 ±0.005 inches of clearance between the stem and the glands.

(2) The valve's stem and glands are both made of stainless steel; since both are of similar hardness, significant galling of the stem results when contact occurs between the two.

(3) The design of the intermediate and upper packing glands (i.e , the height, or depth of the glands and their stacked configuration) aids in their misalignment that results in contact with the stem. A small change in the adjustment of the jam nut, at the top of the gland and on the valve's exterior, can easily produce misalignment of that portion of the gland nearest the valve's stem.

Following the second rework of valve 1F031B, the valve was stroked several times with no evidence of galling. All other Unit 1 and Unit 2 recirculation system suction and discharge valves were inspected using the revised inspection procedure.

2.17 Auxiliary Building Ventilation Isolation (Docket 50-327/LER 84-28)

A high radiation alarm was actuated at the PWR (Westinghouse), causing an auxiliary building isolation to occur. Investigation revealed that personnel were placing boric acid evporator B in service and draining the vent header at the same time that the volume control tank was being vented. This simultaneous action increased the vent header pressure and caused excessive gas to be vented, causing the auxiliary building ventilation system to isolate. The situation has been discussed with operations personnel, and they have been informed of the consequences of venting the volume control tank while venting the waste gas header. Better coordination and information exchange between personnel should prevent this error from occurring in the future.

2.18 Inadvertent Actuation of Recirculation Fans During Maintenance (Docket 50-305/LER 84-04)

With the PWR (Westinghouse) in the refueling operating mode, work was in progress to modify the shield building vent system train B damper actuators. Implementation of the design change required that a contact on a system relay be changed from the normally closed position to the normally open position. An electrician started to disassemble the relay. Removal of the relay face plate released the internal springs of the upper tier of contacts, causing four contacts to change to the closed position. This contact closure actuated the train B recirculation fan. (Type of relay: General Electric CR120.)

Two corrective actions will be taken to prevent recurrence: (1) a description of this event will be entered into the Information and Operational Experience Review Program and circulated to applicable plant and corporate supervisors to review with their personnel; and (2) equipment control practices during modifications will be discussed by the plant Operating Review Committee to determine if any changes in these practices are appropriate.

2.19 Plant Shutdown Due to Damaged Main Steam Line Tunnel Exhaust Duct Temperature Indicators (Docket 50-278/LER 84-06)

With the BWR (General Electric) at 100% power, an inconsistency in the temperature indications for the main steam line tunnel exhaust duct was observed by the Shift Technical Advisor. Investigation revealed that two temperature elements were pulled out of the exhaust duct. This defeated one of two instrument channels in each of two trip systems responsible for initiating a Group I isolation of the primary containment isolation system. As a result, a controlled reactor shutdown was initiated in accordance with technical specifications, and an unusual event was declared. The cause was the result of improper scaffolding installation in the area of the temperature elements. The temperature elements were reinstalled in the duct, and verified as operable.

2.20 Containment Isolation System Design Deficiency (Docket 50-029/LER 84-03)

In preparation for a Westinghouse PWR's containment type A integrated leak rate test (ILRT), solenoid operated isolation valves for the "outside" main coolant system leakage air particulate monitor (MCSLAPM) failed to actuate automatically at an increasing pressure $\underline{F}5$ psig from associated pressure switch, contrary to technical specifications. The solenoid operated valves, which are the containment isolation valves for the MCSLAPM system, were manually tripped at 6 psig to preclude damage, by overpressurization, of the MCSLAPM detector. The plant was in cold shutdown at the time of this event. Following the completion of the type A ILRT, the setpoint for the pressure switch was verified correct with the system isolated. Further investigation into system design and layout revealed a design inadequacy. The design inadequacy was the failure to account for the vacuum under which the pressure switch normally operated. The MCSLAPM was relocated inside containment during the refueling outage.

3.0 ABSTRACTS OF OTHER NRC OPERATING EXPERIENCE DOCUMENTS

3.1 Abnormal Occurrence Reports (NUREG-0090) Issued in March-April 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
4/84	REPORT TO CONGRESS ON ABNORMAL OCCURRENCES, JULY-SEPTEMBER 1983, NUREG-0090, VOL. 6, NO. 3

There were ten abnormal occurrences during the report period. Three occurred at licensed nuclear power plants, and seven were reported by other NRC licensees. The occurrences at the plants involved (1) large diameter pipe cracking since 1982 in boiling water reactors, (2) uncontrolled leakage of reactor coolant outside primary containment at Hatch Unit 2 in August 1982, and (3) improper control rod manipulations at Quad Cities Unit 1 in March 1983 and Hatch Unit 2 in July 1983. The occurrences at other NRC licensees (such as industrial radiographers, medical institutions, and industrial users) involved overexposures, violations of license, misadministrations of radiopharmaceuticals, and widespread radiological contamination.

Also, the report provided update information on the following occurrences previously reported in NUREG-0090: cracks in pipes of boiling water reactors (75-5), first reported in NUREG-75/0090, January-March 1975; nuclear accident at Three Mile Island (79-3), first reported in Vol. 2, No. 1, January-March 1979; and failure of automatic reactor trip system (83-3), first reported in Vol. 6, No. 1, January-March 1983.

In addition, diesel generator (Transamerica Delaval, Inc., Model DSR-48) failures at Shoreham in August 1983 were discussed as an item of interest that did not meet abnormal occurrence criteria.

3.2 Bulletins and Information Notices Issued in March-April 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, two information notice revisions, and 22 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, 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, Institute of Nuclear Power Operations, nuclear steam 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.

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
84-02	3/12/84	FAILURES OF GENERAL ELECTRIC TYPE HFA RELAYS IN USE IN CLASS 1E SAFETY SYSTEMS All holders of nuclear power reactor operating licenses or construction permits were informed about recent HFA relay failures that indicate similarity to previous HFA relay failures reported in several General Electric (GE) Service Advice Letters (SALs) and Service Information Letters (SILs) which were issued to end-users in 1980 and 1982. (See attachments to this bulletin.) Another purpose of this bulletin was to ask licensees and CP holders to inform the NRC about their plans, including schedules, for implementing the manufacturer's recommendations discussed in the subject GE letters. In addition, licensees were asked to provide information concerning their plans to upgrade surveillance and to justify continued operation in the interim.

Information Notice	Date Issued	Subject
84-05, Rev. 1	3/28/84	EXERCISE FREQUENCY All nuclear power reactor facilities holding an operating license or construction permit were notified of certain requirements contained in the final rule (44 CFR 350) published by the Federal Emergency Management Agency (FEMA). This revision identified the lead time needed by NRC to review and process any exemption requested by licensees regarding the lack of participation by State and local governments in annual emergency preparedness exercises. It was expected that recipients would review the information for applicability to their facilities. No written response was required.
84-09 Rev. 1	3/7/84	LESSONS LEARNED FROM NRC INSPECTIONS OF FIRE PROTECTION SAFE SHUTDOWN SYSTEMS (10 CFR 50, APPENDIX R) All nuclear power reactor facilities holding an operating license or construction permit were provided this revision to IE Information Notice No. 84-09 issued on February 13, 1984. Attachment 1 to this revision was a replacement page which provided a needed correction to subparagraph 4 of Section III of IE Information Notice 84-09. Licensees should have added the replacement page. No specific action or response was required as a result of this replacement.
84-14	3/2/84	HIGHLIGHTS OF RECENT TRANSPORT REGULATORY REVISIONS BY DOT AND NRC During 1983, major revisions to nuclear transportation regulations became effective in the U.S.A. Both of the major Federal agencies involved, the NRC and DOT, have published final amendments in the Federal Register which are intended to bring the nuclear transport regulations of the U.S.A. into substantial conformity with the international standards as they currently exist in the International Atomic Energy Agency's 1973 "Regulations for the Safe Transport of Radioactive Material, Safety Series No. 6," as revised. Both the DOT and NRC final amendments were based on earlier Notices of Proposed Rulemaking published by each agency in 1979. In this information notice, all licensees were provided highlights of these amendments.
84-15	3/2/84	REPORTING OF RADIOLOGICAL RELEASES All nuclear power reactor facilities holding an operating license or construction permit were alerted of two recent events involving radioactive gaseous releases. In both events, the offsite radiological

Information Notice	Date Issued	Subject
84-15	3/2/84	REPORTING OF RADIOLOGICAL RELEASES (Continued)

dose consequences were negligible. However, the incomplete or anomalous initial reporting and the lack of aggressive licensee followup for these events clearly demonstrate that (1) more attention could be given to better screening of initial reports to the NRC, and (2) more effort could be made to actively follow up and provide timely closure for radiological events. No specific licensee action or response was required.

On a somewhat related matter, recent random checks with licensees reveal that some facilities do not have the correct backup phone numbers for contacting the NRC Operations Center in the event of a failure to the Emergency Notification System (ENS). On June 1, 1982, the commercial telephone number of the Operations Center was changed to 202-951-0550. The new number was disseminated via IE Information Notice No. 82-15 dated May 28, 1982. In addition, Attachment 1 to this notice provides three additional telephone numbers for use in the event of an ENS failure. As IE Information Notice No. 82-15 pointed out, changes to licensee procedures may be necessary to accommodate the new numbers.

84-16 3/2/84 FAILURE OF AUTOMATIC SPRINKLER SYSTEM VALVES TO OPERATE

All nuclear power reactor facilities holding an operating license or a construction permit were notified of a problem involving the operational failure of deluge and pre-action fire protection water control valves, identified as Model C, manufactured by Automatic Sprinkler Corporation of America of Cleveland, Ohio. It was expected that recipients would review this information notice for applicability to their facilities. No specific action or response was required. (See also Power Reactor Events, Vol. 5, No. 5, pp. 8-9.)

84-17 3/5/84 PROBLEMS WITH LIQUID NITROGEN COOLING COMPONENTS BELOW THE NIL DUCTILITY TEMPERATURE

All holders of nuclear power reactor operating licenses or construction permits were advised of potentially significant problems associated with the use of liquid nitrogen that may cool components below the nil ductility temperature (NDT) of associated materials susceptible to brittle fracture. It was expected that the recipients of this notice would review the information for applicability to their facilities. No specific action or response was required. (See also Power Reactor Events, Vol. 6, No. 1, pp. 1-4.)

Information Notice	Date Issued	Subject
84-18	3/7/84	STRESS CORROSION CRACKING IN PRESSURIZED WATER REACTOR SYSTEMS All nuclear power reactor facilities holding an operating license or construction permit were reminded that PWR systems are susceptible to stress corrosion cracking in the presence of various corrodants. Information was also presented on actions which, if properly and conscientiously implemented, can significantly reduce the likelihood of such cracking.
84-19	3/21/84	TWO EVENTS INVOLVING UNAUTHORIZED ENTRIES INTO PWR REACTOR CAVITIES All nuclear power plant facilities holding an operating license or a construction permit were provided early notification of a recurring problem pertaining to unauthorized personnel entries into the cavity beneath the reactor vessel (reactor cavity) while the retractable incore detector thimbles are withdrawn. Although these recent events did not result in personnel exposures in excess of regulatory limits, it was fortuitous that none of the workers remained in the reactor cavity for longer periods of time. It was expected that recipients would review this information for applicability to their facilities and consider actions, if appropriate, to preclude a similar problem occurring at their facilities. Suggestions contained in this information notice did not constitute NRC requirements and, therefore, no specific action or written response was required. However, the NRC staff is considering the need for further regulatory action, because it is evident that some licensee high radiation area access control programs are inadequate to prevent unauthorized entries into areas where radiation levels of thousands of roentgens per hour (R/hr) can exist. Entry into radiation fields of this magnitude can seriously jeopardize the health and safety of personnel. (See also Power Reactor Events, Vol. 6, No. 1, pp. 15-18.)
84-20	3/21/84	SERVICE LIFE OF RELAYS IN SAFETY-RELATED SYSTEMS All holders of a nuclear power reactor operating license or construction permit were notified of potentially significant problems pertaining to the service life of relays in safety-related systems. These problems are similar to those discussed in IE Bulletin No. 84-02, and the general concerns associated with the HFA relay failures discussed in that bulletin

Information Notice	Date Issued	Subject
84-20	3/21/84	SERVICE LIFE OF RELAYS IN SAFETY-RELATED SYSTEMS (Continued) apply to the problems described in this notice. It was expected that recipients would review the information for applicability to their facilities and consider actions, if appropriate, to preclude similar problems occurring at their facilities. No specific action or written response was required.
84-21	3/28/84	INADEQUATE SHUTDOWN MARGIN All nuclear research reactor facilities holding an operating license were notified of a potentially significant problem pertaining to the lack of an adequate shutdown margin at a nuclear research reactor facility. It was expected that recipients would review the information for applicability to their facilities and consider actions, if appropriate, to preclude a similar problem occurring at their facilities. No specific action or written response was required.
84-22	3/29/84	DEFICIENCY IN COMSIP, INC. STANDARD BED CATALYST All nuclear power reactor facilities holding an operating license or construction permit were notified of a potentially significant problem pertaining to a deficiency in the configuration of the catalyst bed used in models K-III and K-IV containment gas monitoring systems (CGMS) manufactured by Comsip, Inc., of Whittier, California. It was expected that recipients would review the information for applicability to their facilities. No specific action or written response was required.
84-23	4/5/84	RESULTS OF THE NRC-SPONSORED QUALIFICATION METHODOLOGY RESEARCH TEST ON ASCO SOLENOID VALVES All nuclear power reactor facilities holding an operating license or construction permit were provided early notification of a potentially significant event concerning the failure of two naturally aged Automatic Switch Company (ASCO) solenoid valves. These valves are ASCO models NP-8316 and NP-8344. The failure of these two naturally aged valves occurred during the LOCA/MSLB (loss-of-coolant accident/main steam line break) simulation phase of a qualification methodology research test conducted by the Franklin Research Center (FRC). It should be noted that this information notice did not address the earlier concerns dealing with the Viton/EPDM material used in ASCO solenoid valves as

Information Notice	Date Issued	Subject
84-23	4/5/84	RESULTS OF THE NRC-SPONSORED QUALIFICATION METHODOLOGY RESEARCH TEST ON ASCO SOLENOID VALVES (Continued) described in previously published information notices. It was expected that recipients would review the information for applicability to their facilities and take appropriate action. A response was not required.
84-24	4/5/84	PHYSICAL QUALIFICATION OF INDIVIDUALS TO USE RESPIRATORY PROTECTIVE DEVICES All nuclear power plant facilities holding an operating license or construction permit and research and test reactors, fuel facilities, and Priority I material licensees were notified of the recent death of an individual wearing a respirator. The individual had been medically qualified by the licensee to use respiratory protective devices per the requirement stated in 10 CFR 20.103(c)(2). Guidance was provided that licensees may find helpful in their continuing efforts to ensure that respirator users are medically qualified. It was expected that addressees would review the information provided for applicability to their respiratory programs. No specific action or written response was required.
84-25	4/16/84	RECENT SERIOUS VIOLATIONS OF NRC REQUIREMENTS BY RADIOGRAPHY LICENSEES All byproduct materials licensees authorized to possess and use byproduct materials in industrial radiography, and manufacturers who distribute devices that incorporate sealed sources for such use, were informed of the large number of recent cases involving serious violations of NRC license conditions, to point out the common causes of these violations, and to describe their consequences.
84-26	4/16/84	RECENT SERIOUS VIOLATIONS OF NRC REQUIREMENTS BY MOISTURE DENSITY GAUGE LICENSEES All byproduct materials licensees authorized to possess and use byproduct materials in moisture density gauges, and manufacturers who distribute devices that incorporate sealed sources for such use, were informed of the large number of recent cases involving serious violations of NRC license conditions, to point out the common causes of these violations, and to describe their consequences.

Information Notice	Date Issued	Subject
84-27	4/17/84	RECENT SERIOUS VIOLATIONS OF NRC REQUIREMENTS BY MEDICAL LICENSEES All byproduct materials licensees authorized to possess and use byproduct materials in institutional medical programs were informed of the large number of recent cases involving serious violations of NRC license conditions, to point out the common causes of these violations, and to describe their consequences.
84-28	4/17/84	RECENT SERIOUS VIOLATIONS OF NRC REQUIREMENTS BY WELL LOGGING LICENSEES All byproduct materials licensees authorized to possess and use byproduct materials in well logging devices, and manufacturers who distribute devices that incorporate sealed sources for such use, were informed of the large number of recent cases involving serious violations of NRC license conditions, to point out the common causes of these violations, and to describe their consequences.
84-29	4/17/84	GENERAL ELECTRIC MAGNE-BLAST CIRCUIT BREAKER PROBLEMS All nuclear power reactor facilities holding an operating license or construction permit were notified of a potential generic problem concerning worn-out sleeve bearings that recently have caused circuit breaker closure failures at the Diablo Canyon nuclear station. Information also was presented on recommended actions by the breaker manufacturer (GE). These actions, if implemented, can significantly alleviate the cause of the wear problem in the breaker sleeve bearing. It is expected that recipients would review the information for applicability to their facilities and consider actions, if appropriate, to preclude a similar problem occurring at their facilities. No specific action or written response was required.
84-30	4/18/84	DISCREPANCIES IN RECORDKEEPING AND MATERIAL DEFECTS IN BAHNSON HEATING, VENTILATION, AND AIR CONDITIONING UNITS All nuclear power reactor facilities holding an operating license or construction permit were informed of a potentially significant problem pertaining to heating, ventilation, and air conditioning (HVAC) equipment manufactured by the Bahnson Company. The NRC expected recipients to review this notice for applicability to their facilities. No specific action or written response was required.

Information Notice	Date Issued	Subject
84-31	4/18/84	INCREASED STROKING TIME OF BETTIS ACTUATORS BECAUSE OF SWOLLEN ETHYLENE-PROPYLENE RUBBER SEALS AND SEAL SET All nuclear power facilities holding an operating license or construction permit were notified of potentially significant problems pertaining to actuators manufactured by the G. H. Bettis Company. One problem involved the use of ethylene-propylene rubber (EP) in contact with a lubricant, Mobil 28 grease, which deformed the seals. The other problem was seal "set" when actuators are not exercised frequently. The NRC staff expected recipients to review this notice for applicability to their facilities and consider actions, if appropriate, to preclude similar problems from occurring at their facilities. No specific action or written response was required.
84-32	4/18/84	AUXILIARY FEEDWATER SPARGER AND PIPE HANGER DAMAGE All holders of nuclear power reactor operating licenses or construction permits (CPs) for pressurized water reactors were advised of an event involving sparger and pipe hanger damage, which apparently was caused by water hammer in the auxiliary feedwater system despite specific design considerations intended to preclude such an event. The NRC expected recipients of this notice to review the information for applicability to their facilities and consider actions, if appropriate, to preclude a similar problem occurring at their facilities. No specific action or written response was required.
84-33	4/20/84	MAIN STEAM SAFETY VALVE FAILURES CAUSED BY FAILED COTTER PINS All nuclear power reactor facilities holding an operating license or a construction permit were notified of a potentially significant problem pertaining to a failure mode of safety and safety/relief valves caused by failed cotter pins. It was expected that recipients would review the information for applicability to their facilities and consider actions, if appropriate, to preclude a similar problem occurring at their facilities. No specific action or written response was required. (See also Power Reactor Events, Vol. 6, No. 1, p. 18.)

Information Notice	Date Issued	Subject
84-34	4/23/84	RESPIRATOR USER WARNING: DEFECTIVE SELF-CONTAINED BREATHING APPARATUS AIR CYLINDERS All nuclear power reactor facilities holding an operating license or construction permit, and research and test reactor facilities, fuel cycle licensees, and Priority 1 material licensees were alerted of a serious defect in self-contained breathing apparatus (SCBA) hoop-wrapped aluminum air cylinders rated at 4,500 psi, manufactured under the Department of Transportation (DOT) Exemption DOT-E 7235. During refilling operations at a fire department, one cylinder ruptured and injured one person. The National Institute of Occupational Safety and Health (NIOSH) has issued a Respiratory Users Notice, in concert with a DOT Federal Register Notice limiting filling/operating pressure of the affected cylinders to 4,000 psi until further notice. NRC regulations require that only NIOSH-certified respiratory equipment shall be used as emergency devices. Licensees were expected to review the information for applicability to their facilities' respiratory protection program and take actions, as required, to maintain NIOSH and DOT certifications for affected equipment and to minimize the probability of catastrophic cylinder failure. Further NRC action may occur after the DOT/NIOSH evaluations are completed and reviewed by the staff. No written response to this notice was required.
84-35	4/23/84	BWR POST-SCRAM PRESSURIZATION All boiling water power reactor facilities holding an operating license or construction permit were notified of events that resulted in drywell pressure increases following a reactor scram and the subsequent unavailability of systems that could be used to reduce drywell pressure. The NRC expected recipients of this notice to review the information for applicability to their facilities and consider actions, if appropriate, to preclude a similar problem occurring at their facilities. No specific action or response is required. (See also Power Reactor Events, Vol. 4, No. 5, pp. 1-4, and Vol. 5, No. 4, pp. 5-9.)

3.3 Case Studies and Engineering Evaluations Issued in March - April 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
C401	3/84	LOW TEMPERATURE OVERPRESSURE EVENTS AT TURKEY POINT UNIT 4 At Turkey Point Unit 4 on November 28 and 29, 1981, during the filling and venting process while restarting the reactor after a refueling outage, two overpressure events occurred within 24 hours. The first one exceeded by a factor of two the technical specification limits. Both trains of the overpressure protection system were inoperable and operator actions were required to mitigate the pressure transients to prevent a more severe pressure excursion. The generic safety significance of these events is the possibility of the reactor vessel failure by brittle fracture as a consequence of similar overpressure transients during low temperature operation. These overpressurization transients at Turkey Point were the first events to exceed the technical specification limits at an operating pressurized water reactor (PWR) since the NRC staff resolved the generic issue of low temperature overpressure (LTOP) transients in 1979.

Case Study	Date Issued	Subject
C401	(continued)	In this case study, the technical specifications for low temperature overpressure (LTOP) protection were reviewed and generally found to be inadequate to (1) prevent overpressure transients, and (2) ensure redundancy in the overpressure mitigating system during the short time interval that the system may be required to protect the vessel from brittle fracture. These deficiencies are germane to the existing technical specifications at operating PWRs that have low temperature overpressure protection requirements, and to the Standard Technical Specifications. Some operating plants do not have LTOP technical specifications. The AEOD evaluation of solid plant operations (e.g., no steam or gas bubble in the pressurizer) concluded that this is an undesirable mode of operation that poses the major risk for overpressure events and that it can be minimized or eliminated during the filling and venting process. AEOD proposed (1) that the nuclear industry further evaluate the need for water solid operation and consider developing a recommended operating practice for filling and venting PWRs which excludes water solid operation, and (2) that the NRC correct the identified deficiencies in the LTOP technical specifications.

Engineering Evaluation	Date Issued	Subject
E323 Rev. 1	3/27/84	LOAD REDUCTION TRANSIENT AT THE SALEM NUCLEAR POWER PLANT, UNIT 2, ON JANUARY 14, 1982 This study evaluated the significance and safety implications of the January 14, 1982 load reduction transient at Salem Unit 2. The event involved five separate and unrelated failures including a complete failure of the rod control system, and was initiated by a feedwater transient involving a loss of suction to the feedwater pumps. A power mismatch of 70% between reactor power and turbine load occurred during the event. Elevated average temperature (Tavg) exceeded the technical specification limits, but plant stability was restored without a trip to preclude an overcooling transient. Although the scram function was available, there was no requirement for a reactor trip when the rod control system had failed and the Tavg had exceeded technical specification limits.

Engineering Evaluation	Date Issued	Subject
E323	(continued)	This study evaluated the causes for the transient, system response, operator actions, and the generic implications of the event. Similar events also were considered. Based on the evaluation of the Salem load transient event, AEOD did not identify any safety concerns which warrant corrective actions. However, the number of independent failures and the response by the Salem operators contributed to a significant operating experience which should be communicated to operators to broaden their knowledge and understanding of such an event. (See also Power Reactor Events, Vol. 5, No. 6, pp. 17-19.)
E405	3/22/84	COMMON MODE FAILURE OF HPCI HIGH STEAM FLOW ISOLATION CAPABILITY On July 23, 1982, surveillance testing at Browns Ferry Unit 2 indicated that both channels of the high pressure coolant injection (HPCI) system's high steam flow instrumentation were inoperable. Inoperability was due to a partially stuck open instrument block manifold equalizing valve. The open valve would have prevented generation of proper differential pressure across both of the redundant differential pressure (dp) sensors. This event was investigated to evaluate the consequences of a loss of both HPCI high steam flow instrument trains. The failure of these instruments would disable one of the two principal signals provided for detecting and isolating breaks in the HPCI steam supply line. Equipment area temperature sensors also provide a signal to detect and initiate isolation over the full HPCI break spectrum. The results of this investigation indicate that, even with a loss of high steam flow isolation capability, the area temperature sensors will provide adequate break detection and isolate the HPCI steam line. Therefore, BWR plants which are susceptible to this common mode failure of their high steam flow instruments are adequately protected by the area temperature sensors or the detection and isolation of HPCI steam line.
E406	3/22/84	MECHANICAL SNUBBER FAILURE During the Dresden Unit 2 refueling outage on February 10, 1983, while performing snubber stroke

Engineering Evaluation	Date Issued	Subject
E406	(continued)	tests, five safety-related mechanical snubbers installed on the main steam line headers adjacent to safety relief valves (SRVs) inside the drywell were found to be damaged and in a locked-up condition. The failed snubbers are Model PSA-10 manufactured by Pacific Scientific Company and had been installed during the previous refueling outage. The failures were not found on other Commonwealth Edison units utilizing the same type of mechanical snubbers. The licensee conducted an extensive program to monitor and verify the operations transients in the four-month period between March and June of 1983. The actual cause of the failures was not determined by this program; however, it does not appear that a dynamic transient overload was the cause. A search of files from 1980 to the present for failure mechanisms of mechanical snubbers made by Pacific Scientific revealed that, in addition to dynamic overloads, the effects of a snubber being twisted, piping vibration, or excessive bending force have caused snubber failures similar to that at Dresden 2 in which the snubber became locked-up as a result of internal component damage. There were a total of 11 mechanical snubbers found to be defective in this search, seven due to twisting at Virgil C. Summer 1, two due to piping vibration at Sequoyah 2 and Duane Arnold (one for each plant), and two due to excessive bending force at LaSalle County 1. Additionally, more than 100 mechanical snubber failures were reported in response to IE Bulletin 81-01, but were not in the LER data system. None of the damaged snubbers were detected by visual inservice inspection during plant operation. This may indicate that the current NRC requirements for visual inservice inspection for safety-related mechanical snubbers are not adequate to verify operability of these components with the likelihood there are undetected, locked-up mechanical snubbers in operating plants.
E407	3/26/84	INITIATION AND INDICATION CIRCUITRY FOR HIGH PRESSURE COOLANT INJECTION (HPCI) SYSTEMS During an NRC inspection at the Shoreham plant in September 1983, the HPCI circuitry did not appear to meet the intent of IEEE Standard 279-1971. The concern noted was that for certain conditions, the

Engineering Evaluation	Date Issued	Subject
E407	(continued)	HPCI system function would not go to completion once initiated, although the indication circuitry would respond as though the system had gone to completion. As a result of this observation, the licensee committed to initiate a design change to remove the concern regarding compliance with the required IEEE Standard. In view of the identified concern regarding the HPCI circuitry at the Shoreham Nuclear Power Station, a review was performed of the HPCI initiation and indication circuitry for three additional BWR facilities to identify if a similar concern is applicable to these facilities. The result of this review was that the concern is applicable to the HPCI circuitry for two of the three facilities. Based on review of this issue, it is believed that the actions taken at the Shoreham Nuclear Power Station were appropriate, and if implemented properly, they should remove the concern regarding compliance with the intent of the required IEEE Standard. Also, in view of the finding regarding two additional facilities, it is felt that consideration should be given to reviewing the identified area of the HPCI circuitry of other BWR facilities so as to verify that this area of the circuitry is in conformance with the intent of the required standard.
E408	4/13/84	REVERSED DIFFERENTIAL PRESSURE INSTRUMENT SENSING LINES A study was performed to evaluate licensing events involving differential pressure instruments that were found with the high and low pressure sensing lines installed backwards. Almost all of the events which were found occurred at boiling water reactor facilities. The great majority could be sorted into groups comprised of multiple errors at either the same plant site or the same licensee/contractor/architect-engineer. The pattern of multiple events indicates that potential inadequacies may have existed in the design and/or installation quality assurance control measures at the involved facilties. Several of the installation errors went undetected for several years and effectively disabled both of the redundant instrument trains used for automatic initiation of a containment isolation function. The use of inadequate preoperational and/or startup test procedures is considered the principal reason for the errors being overlooked. The evaluation concludes that only the

Engineering Evaluation	Date Issued	Subject
E408	(continued)	sensing lines used for the high flow isolation instruments of the isolation condensers of early generation BWRs still may be suspected of being incorrectly installed because of potentially inadequate startup testing procedures. It is suggested that the sensing line installations for these instruments be verified at the affected plants either as part of the next scheduled functional test of the isolation condensers or by review of the initial startup test procedures.

3.4 Generic Letters Issued March - April 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 March and April 1984, seven 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	Subject
84-05	4/2/84	CHANGE TO NUREG-1021, "OPERATOR LICENSING EXAMINER STANDARDS" All power reactor licensees and applicants for operating licenses were notified of the availability of NUREG-1021. Recently, the NRC has revised NUREG-1021, ES-201, Section H to improve the security of the written operator and senior operator licensing examination administration procedure while maintaining a meaningful review by facility representatives. A copy of this change was enclosed with this letter. It was also noted that comments on NUREG-1021 are welcome and will be considered in future revisions.
84-06	4/16/84	OPERATOR AND SENIOR OPERATOR LICENSE EXAMINATION CRITERIA FOR PASSING GRADE All non-power reactor licensees were notified that the NRC is in the process of revising the Examiner Standards that provide guidance for the administration of examinations to non-power license candidates. The guidance for power reactors has already been modified to reflect changes made since the TMI-2 accident and issued as NUREG-1021, "Operator Licensing Examiner Standards." The non-power reactor guidance is still in the process of revision and will be issued an an addendum to NUREG-1021 when completed. This generic letter was intended to reaffirm the passing grade criteria for operator and senior operator license examinations at non-power reactors pending the revision of NUREG-1021 to incorporate these requirements.

Generic Letter	Date Issued	Subject
84-06	(continued)	The current Examiner Standards applicable to non-power reactors (ES-203, 2/15/69) advise examiners to structure the written examinations such that a qualified operator would score above 70% on the entire examination and in each category. Therefore, a candidate will be required to achieve a score of 70% or greater in each category of the examination in order to pass the non-power reactor operator or senior operator written examination. As stated in 10 CFR Part 55.12, "Reapplications," the Commission may in its discretion grant requests for waivers on portions of the examination which have been previously passed.
84-07	3/14/84	PROCEDURAL GUIDANCE FOR PIPE REPLACEMENT AT BWRS This letter provided guidance to all boiling water reactor (BWR) licensees planning to replace recirculation system piping (or other reactor coolant system pressure boundary piping) with material that is less susceptible to intergranular stress corrosion cracking. In particular, guidance was provided regarding NRC reviews and approvals that may be necessary.
84-08	4/4/84	INTERIM PROCEDURES FOR NRC MANAGEMENT OF PLANT-SPECIFIC BACKFITTING This letter advised all licensees of operating reactors, applicants for operating licenses, and holders of construction permits that the Commission has recently approved a plan for management of plant-specific backfitting issues. The Commission has directed the staff to seek public comment regarding the plan. This plan and the interim procedures will be published in the Federal Register. Until public comments are received and the plan for management of plant-specific backfitting issues is finalized, the NRC staff intends to use the enclosed procedures (Draft Manual Chapter 0514) as interim guidance.
84-10	4/26/84	ADMINISTRATION OF OPERATING TESTS PRIOR TO INITIAL CRITICALITY (10 CFR 55.25) On April 13, 1984, the Commission met to consider the existing staff practice of allowing satisfactory completion of an approved cold license training program as meeting the 10 CFR 55.25 (b) requirement for extensive actual operating experience at a comparable facility. They determined that additional rule-making action was required to clarify the

Generic Letter	Date Issued	Subject
84-10	(continued)	Commission position that satisfactory completion of NRC-approved training programs could be substituted for experience requirements. They directed the Office of the General Counsel to initiate a rulemaking to make 10 CFR 55.25 (b) fully consistent with current staff practice. They also affirmed that operator licenses in effect will remain valid. This letter informed applicants for an operating license that all applicants for Reactor Operator (RO) and Senior Reactor Operator (SRO) licenses at facilities prior to initial criticality who have not had extensive actual operating experience at a comparable facility must obtain an exemption to 10 CFR 55.25 (b) if they meet certain conditions discussed, pending completion of this NRC rulemaking effort.
84-11	4/19/84	INSPECTIONS OF BWR STAINLESS STEEL PIPING Inspections conducted at several boiling water reactors (BWRs) revealed intergranular stress corrosion cracking (IGSCC) in large-diameter recirculation and residual heat removal piping. The Commission believes that the results of these inspections mandate an ongoing program for similar reinspections at all operating BWRs. Where IGSCC is discovered, repairs, analysis and additional surveillance may also be required to ensure the continued integrity of affected pipes. Pursuant to 10 CFR 50.54(f), BWR operating reactor licensees and applicants for an operating license (this letter is for information only for those utilities that have not applied for an operating license) were requested, in order to determine whether a license should be modified or suspended, to furnish no later than 45 days from the date of this letter, current plans relative to inspections for IGSCC and interim leakage detection.
84-12	4/30/84	COMPLIANCE WITH 10 CFR PART 61 AND IMPLEMENTATION OF THE RADIOLOGICAL EFFLUENT TECHNICAL SPECIFICATIONS (RETS) AND ATTENDANT PROCESS CONTROL PROGRAM (PCP) This letter informed all operating reactor licensees and applicants for operating licenses that the waste manifest provisions of 10 CFR 20.311 became effective on December 27, 1983. The manifest system is closely related to certain requirements of 10 CFR Part 61 that place new requirements on classification and

Generic Letter	Date Issued	Subject
84-12	(continued)	acceptable forms for low-level radioactive wastes being shipped from commercial nuclear power plants to commercial disposal facilities. During the development of Part 61, the NRC staff determined that compliance with the radioactive waste form requirements of Part 61 and the certification requirements of 10 CFR 20.311 could be achieved by the development and use of a Process Control Program (PCP) as an attendant part of the licensee's Radiological Effluent Technical Specifications (RETS). This approach was determined to be acceptable by the responsible State regulatory agencies that license the disposal sites. It is now apparent, however, that many licensees do not yet have approved PCPs and that no licensee has a PCP which specifically addresses the new requirements of Part 61. As an interim measure, the responsible State regulatory agencies and the disposal site operators have agreed to continue to accept nuclear power plant low-level reaioactive wastes based upon the NRC staff's assurance that reasonable progress is being made toward demonstration of full compliance with new requirements of Part 61 and Part 20.

3.5 Operating Reactor Event Memoranda Issued in March - April 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 Offices for Analysis and Evaluation of Operational Data, and of Inspection and Enforcement for their information.

No OREMs were issued during March - April 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) nondocketed 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.

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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