NUREG/BR-0051
Vol. 9, No. 4

POWER REACTOR EVENTS

United States Nuclear Regulatory Commission

Date Published: AUGUST 1988

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 in the USNRC Public Document Room at 1717 H Street, Washington, D.C. 20555 for public inspection and/or copying. Subscriptions of Power Reactor Events may be requested from the Superintendent of Documents, P.O. Box 37082, U.S. Government Printing Office, Washington, D.C. 20402, or by calling (202) 783-3238.

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Published by:
Office for Analysis and Evaluation
of Operational Data
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Period Covered: July–August 1987

The events included in this report were selected by the NRC Office for Analysis and Evaluation of Operational Data (AEOD). The report was prepared for AEOD, under contract FIN F0051, by:

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1.0 SUMMARIES OF EVENTS

1.1 Steam Generator Tube Rupture at North Anna 1

At approximately 6:30 a.m. on July 15, 1987, North Anna Unit 1* was at 100% power and Unit 2 at 81% power in an end of cycle power coastdown. A high radiation alarm was received on the Unit 1 steam generator C main steam line. At the same time, pressurizer level and pressure began to decrease rapidly.

At 6:35 a.m., with pressurizer level at approximately 45% (normal level is 65%) and pressure at 2100 psig (normal operating pressure is 2235 psig), Unit 1 was manually tripped. Approximately 20 seconds later, an automatic actuation of the safety injection system occurred due to low-low pressurizer pressure (less than 1765 psig on 2 out of 3 channels). By 6:48 a.m., the C steam generator was identified as having positive indication of tube rupture.

A Notification of Unusual Event was declared at 6:39 a.m. and notifications to state and local governments were completed by 6:51 a.m. The event was upgraded to an Alert at 6:54 a.m. and the notifications to all off-site agencies and the Nuclear Regulatory Commission (NRC) were completed by 7:02 a.m. An orderly cooldown and depressurization of the reactor coolant system to cold shutdown conditions was initiated at 7:18 a.m. and the emergency was terminated at 1:36 p.m.

Prior to the event, the condenser air ejector radiation monitor, RM-RMS-121 was declared inoperable due to erratic operation. This radiation monitor would have provided a signal to divert the condenser air ejector flow from the atmosphere to the containment building had it been operable and if its highest setpoint had been exceeded. No other safety-related equipment was out of service at the time of the event. All other safety-related equipment performed as expected.

Several radiological release paths to the environment were present during this event. The condenser air ejector discharged to atmosphere until it was manually diverted to the containment building at 7:56 a.m. The steam driven auxiliary feedwater pump, 1-FW-P-2, started on the safety injection signal and its steam supply from the C steam generator was isolated from the turbine driven auxiliary pump at approximately 6:48 a.m. A minor release path existed when two relief valves, one on the B main feedwater pump suction and one on the tube side of the 2A feedwater heater, lifted and did not reseat when pressure had returned to normal. An operator manually adjusted the relief valve setpoints to allow them to close, which was completed about 30 minutes into the event.

Analysis of the radiological data indicated that a total of 1.59×10^{-1} curies was released, primarily in the form of gas. There was no detectable increase in normal background levels of radioactivity at the site boundary.

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*North Anna Unit 1 is a 907 MWe (net) MDC Westinghouse PWR located 40 miles northwest of Richmond, Virginia, and is operated by Virginia Electric and Power.

After the emergency was terminated at 1:36 p.m., the recovery phase of the emergency plan was initiated. An inspection of Unit 1 steam generator tubes was performed to determine the location and root cause of the ruptured tube, and to provide the information needed to take necessary corrective action. An evaluation of this event has shown that the consequences of the steam generator tube rupture event were bounded by the analysis contained in the Final Safety Analysis Report. In terms of public health consequences, the event had no effect. Core thermal margins and shutdown margins were met and fuel integrity was not compromised.

Subsequent investigation revealed that tube number R9-C51 of steam generator C ruptured. Analysis determined that the failure was the result of flow induced vibration. A total of 253 tubes in all three steam generators were plugged during the ensuing plant outage. Additional measures to detect failing steam generator tubes were implemented. These included installation of N-16 monitors on the secondary side, estimating primary-to-secondary leakage every four hours, and trending leakage rates. Plant shutdown was set at conservative limits below that required by the Technical Specifications. More detailed information is available in References 2 through 5.

1.2 Faulty 500KV Circuit Breaker Leads to Loss of Non-emergency AC Power at Calvert Cliffs Units 1 and 2

On July 23, 1987, Calvert Cliffs Unit 1 and Unit 2 were operating at 100% power. At 3:25 p.m. a phase-to-ground fault developed on phase C on one of two 500KV transmission lines connecting Calvert Cliffs to the Baltimore Gas & Electric (BG&E) bulk power distribution grid at Waugh Chapel Station. The fault developed when a tree came in contact with the transmission line. Circuit breakers for the line at Waugh Chapel and Calvert Cliffs tripped open to isolate the fault. At about the same time the circuit breakers at Calvert Cliffs for the other 500KV transmission line incorrectly tripped upon sensing the fault. A defective logic circuit card in the primary static protective relay circuit allowed the primary relays to trip the circuit breakers at Calvert Cliffs despite the absence of a permissive signal to trip from associated relays at Waugh Chapel. The circuit breakers at Waugh Chapel remained closed, as designed, after sensing that the fault was on another transmission line.

The opening of circuit breakers on both 500KV transmission lines isolated Calvert Cliffs from the rest of the power grid. Both Unit 1 and Unit 2 tripped on loss of load followed immediately by a loss of all non-emergency ac power. All three emergency diesel generators (EDG) started automatically on receipt of an undervoltage signal on the engineered safety features 4KV buses. EDG 11 and 21 automatically energized 4KV buses 11 and 24 respectively, while EDG 12 was selected by the operators to energize 4KV bus 14. The appropriate emergency operating procedures were initiated on both units to place the plants in a stable condition. Natural circulation was observed on both reactors.

At 3:30 p.m., an Alert condition was declared to assist in the recovery from loss of all off-site electrical power. The alert condition was downgraded at

5:00 p.m. to an Unusual Event after completion of a check of the 500KV switchyard. At 5:23 p.m., alternate off-site electrical power was established to engineered safety features 4KV bus 21 from the Southern Maryland Electric Cooperative (SMECO) 13KV line. Establishment of this power source was delayed due to a trip of the SMECO circuit breaker at their 69KV/13KV substation while the operators were initially energizing the unloaded 13KV/4KV transformer. Although the exact cause of the breaker trip is unknown, operators failed to open the warehouse breaker off of the SMECO line, as required in the operating instructions. The warehouse breaker was subsequently opened and the SMECO line was reenergized and power was brought to the 4KV bus without incident. A review of the operation and design of the SMECO line was initiated.

At 7:10 p.m., normal off-site electrical power was reestablished to the 500KV/13KV service transformers. Operators then restored the normal electrical lineup for both units. At 10:10 p.m., the Unusual Event was terminated when forced circulation in both reactors was restored at about 8:45 p.m.

Unit 2 was returned to service and paralleled to the power grid at 8:55 a.m. the next day. Restoration of Unit 1 was delayed because the 11A reactor coolant pump (RCP) motor failed after attempted restart after the trip. Cause of the RCP failure was an internal fault in the motor winding. After the 11A RCP motor was changed out, Unit 1 was restored to operation on August 5.

Operators experienced some difficulty during this event while starting the steam-driven auxiliary feedwater pumps in order to minimize EDG electrical loading. Two initial attempts to start AFW pump 11 failed due to high vibration levels which caused the pump trip latch mechanism to trip. AFW pump 11 was successfully started by reducing steam flow to the governor control valve and manually bringing the steam flow up. Subsequent troubleshooting revealed that the overspeed trip linkage was out of adjustment. The linkage was adjusted and the pump was tested satisfactorily.

The licensee determined that this event did not constitute a major safety issue because loss of all non-emergency ac power is evaluated in the Final Safety Analysis Report (FSAR). This event was analyzed for occurrence at 100% power and it was determined that it could not have been more severe under any credible alternative circumstances. The parameter trends were not as severe in this event as those assumed in the FSAR analysis.

1.3 Startup Transformer Failure Causes Loss of Offsite Power at Palisades

On July 14, 1987, at 1:22 p.m., the Palisades Nuclear Plant* experienced a loss of offsite power while at 91% power. The loss of offsite power resulted in the loss of cooling tower pumps and fans. The Shift Supervisor directed the reactor to be manually tripped due to the forthcoming loss of condenser vacuum. The two plant emergency diesel generators provided power until offsite power was restored at 8:04 p.m. The plant was maintained in hot shutdown using natural circulation until forced circulation was restored at 10:21 p.m. An Unusual Event was declared at 1:30 p.m. and was terminated at 8:49 p.m.

Plant technicians were working to correct an alarm problem on the main transformer deluge system. The air pressure systems for the main transformer and the startup transformer deluge systems are cross connected. After calibration of the main transformer pressure switch, the system air pressure was increased and then decreased to balance the system. The deluge system actuates on differential pressure across a diaphragm. One side of the diaphragm has system air pressure, the other side has air pressure from a heat actuated device (HAD). Under normal circumstances the air pressure is equal on both sides of the diaphragm, with a compensating vent maintaining this equilibrium. However, when the HAD sees a rapid rise in temperature, the air expands. This increases the air pressure faster than the compensating vent can release it, thus pushing the diaphragm in and releasing a weight latching mechanism, allowing the deluge valve to open. In this event, air supply pressure was reduced too quickly. This resulted in the air pressure on the HAD side of the diaphragm to be greater and therefore, the diaphragm moved and released the weight latch.

Shortly after the deluge system actuated, an arc jumped from the Y phase insulator bushing cap to the transformer case of the 1-2 startup transformer. The arc created a ground fault on the Y phase. The ground fault was sensed by the primary and backup bus differential relays which in turn initiated trips on the 345KV switchyard bus R air blast breakers and the startup power breakers for the cooling tower system. The normal fast transfer to startup power after a reactor trip was blocked due to the fault sensed from the arc. The diesel generators loaded onto their respective buses via the normal shutdown sequence as designed.

Reactor trip and emergency procedures for loss of forced circulation and initial safety function checks were completed and natural circulation flow was verified by 1:39 p.m. Major plant equipment responded as expected during the plant trip with the exception of the quick-open feature for the atmospheric steam dump valves and the turbine bypass valve. These valves did not open until between 18 and 31 seconds after the plant trip. The plant remained in hot shutdown on natural circulation until 10:21 p.m. when a primary coolant pump was started.

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*Palisades Nuclear Plant is a 805 MWe (net) MDC Combustion Engineering PWR located 5 miles south of South Haven, Michigan and is operated by Consumers Power.

Activities to electrically backfeed the plant through the main transformer were commenced at 3:50 p.m. and completed at 7:50 p.m. These activities proceeded in a deliberate manner to allow the balance of switchyard breakers to be checked, to verify status of the main transformer (used for backfeed), and to assure all relaying had properly functioned. Plant management intent at this time was to proceed with the recovery phase cautiously since the plant was operating very well under natural circulation and no risks for disrupting natural circulation were foreseen. At 7:50 p.m., buses 1E, 1A and 1B were restored to service via backfeeding through the main transformer. However, on the first attempt to backfeed bus 1C, a load shed signal was received and the 1C bus was reloaded onto the 1-1 diesel generator via the normal shutdown sequencer. Subsequent investigation revealed that two startup transformer auxiliary relays were not reset per the operating procedure. These relays were reset and buses 1C and 1D were then fed from offsite power at 8:48 p.m. The procedure for loss of ac power was corrected to include restoration of these two relays when backfeeding the 1C and 1D buses.

The root cause of the fault was contamination in the transformer deluge system water combined with wind gusts which caused water spray to reach the top of the transformer bushings. Contaminants in the water spray provided a path to ground (i.e., the transformer case) for an electric arc. There was no indication that the arc traveled along the bushing surface or that the arcing was internal to the bushing or transformer. The contamination occurred because water was not periodically flushed from the piping.

The proximate cause of the event was the inadvertent actuation of deluge spray on the startup transformer. Technicians were performing maintenance on the deluge alarm system and had determined that a pressure switch required calibration. After calibration, the system air pressure for the main transformer was repressurized for system operation. While raising the system air pressure for the main transformer deluge system, the regulator was adjusted such that the startup transformer deluge system pressure became too high. The two systems are tied together through a common air supply and pressure regulator. The system air pressure for the startup transformer was lowered by opening an air bleedoff valve. Just as the pressure reached the normal operating range, the startup transformer deluge system activated.

The delayed operation of the turbine bypass valve and the atmospheric steam dump valves was determined to be a failure of turbine trip lockout relay 386/AST. An inspection of the relay revealed that a spacer between the contacts had broken. As a result of the spacer failure the contacts had shifted so as to prevent contact when the cam rotated. This disabled the quick-open feature of the turbine bypass valve and the atmospheric steam dump valves.

The contamination in the deluge water lines was caused by corrosion due to the stagnant water in the piping. This contamination is now reduced by quarterly flushing of the deluge system. The flushing has been incorporated into the periodic fire system checklist. The deluge spray nozzles were tested to determine if they should be adjusted. The test showed none of the nozzles sprayed directly onto the bushing and that no adjustments were necessary. In addition, an engineering review of the deluge system was conducted to determine possible actions which would minimize inadvertent actuation of the deluge system.

The turbine trip lockout relay (386/AST) was replaced prior to plant startup. In addition, a review for similar relays in the plant was conducted. Eleven relays were located and inspected. None of these 11 relays exhibited a similar spacer failure or any other anomalies. The 386/AST relay also provides logic to four control schemes:

1) feedwater pump speed ramp down,
2) closure of turbine generator moisture separator reheater valves,
3) feedwater regulator valve controls and,
4) turbine bypass and atmospheric steam dump valves.

The relay failure was evaluated to determine if it may have contributed to the anomalies observed earlier on June 20, 1987. Those anomalies are described in Licensee Event Report 255-87-018, "Improper Valve Operation Results in Reactor Critical At Less Than 525 °F".

The Licensee determined that the loss of offsite power with a reactor trip is an analyzed transient with no adverse safety consequences. The plant response to the reactor and turbine trip was consistent with its designed operation with the exception of the atmospheric steam dump valve and the turbine bypass valve which both failed to quick open. The review of the primary coolant system parameters indicated that the plant responded as designed even though the quick-open feature did not activate. Natural circulation was established and verified with no problems.

During the transient, the secondary system was exposed to hydraulic disturbances. Inspection of secondary system equipment revealed no signs of damage other than minor denting of insulation. Inspections were performed during startup to look for additional damage which may not have appeared until after startup.

As a precaution, the discharge piping of the feedwater pumps and the condensate pumps was non-destructively tested for possible damage. The test results showed no damage.

Offsite power was lost for over seven hours after the trip. The plant was ready to backfeed after about four hours, but management conservatively decided to further investigate the power system for any undetected damage before backfeeding offsite power through the main transformer.

1.4 Reactor Scram Due to Failure of Main Generator Manual Voltage Regulator Board Transistors at Brunswick Unit 1

At 10:35 a.m., on July 1, 1987, a turbine power/load unbalance relay tripped at Brunswick Steam Electric Plant (BSEP) Unit 1*, causing a main turbine trip and a reactor scram while at 100% power.

Voltage regulation for the main turbine was in the manual mode while troubleshooting the automatic voltage regulator. The regulator had exhibited unstable operation above 80% power. The manual voltage regulator had been placed in service and verified to be controlling properly prior to the event.

Earlier, on June 27, it was noted that the automatic voltage regulator was exhibiting unstable operation above 80% power. Nominal generator field voltage at 100% power is about 250 volts dc; however, fluctuations of as much as 80 volts dc were observed. Functional testing performed at that time determined that the problem was isolated to the automatic voltage regulator.

On June 29, the vendor (General Electric) was called in to observe system behavior and to assist in development of a troubleshooting/repair plan. A special procedure was developed for transferring the voltage regulation to manual, verifying proper operation, and then removing the automatic regulator for troubleshooting and repair. Included in the plan was guidance to verify automatic regulator behavior prior to removal in an attempt to determine possible causes of erratic operation.

On July 1, maintenance personnel and the vendor representative briefed the Operations personnel on the intended course of action. Proper operation of the manual voltage regulator was verified prior to transferring to the manual mode, at which time the manual and automatic regulators were balanced and control was shifted to manual. Operation in the manual mode was monitored for 10 minutes to verify proper operation prior to proceeding. With stable operation verified with the manual regulator, troubleshooting began on the automatic regulator.

The output of the automatic voltage regulator was found to be unstable. The General Electric representative reported that the cause of erratic output was loose terminals and poor solder connections. No loose terminal connections were found on the regulator circuit board; however, while connections were being checked on cabinet-mounted potentiometers, an arc was heard and the output of the manual voltage regulator was lost when a wire to potentiometer A10P was moved. The loss of the manual voltage regulator caused a generator overexcitation condition which caused the turbine to trip on power/load imbalance. A reactor scram followed due to a turbine control valve fast closure signal at 10:35 a.m.

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*Brunswick Unit 1 is a 821 MWe (net) MDC General Electric BWR located 3 miles north of Southport, North Carolina and is operated by Carolina Power & Light.

As a result of the turbine trip and reactor scram, the following actions occurred:

- diesel generators 1 through 4 auto-started but did not load to their respective buses (per design).
- reactor safety relief valve (SRV) A auto-opened on high pressure (per design).
- Primary containment isolation system Groups 1, 2, 3 (outboard valve only), and 6 and 8 auto-isolated on low vessel level (per design).
- A reactor recirculation pump tripped on low vessel level (per design).
- standby gas treatment system auto-started and the reactor building ventilation system isolated on low vessel (per design).
- SRVs A, B, and E were manually lifted to control reactor pressure (per procedure); but SRV J failed to open.
- high pressure coolant injection (HPCI) system was manually started for pressure control; the system tripped on overspeed during the starting sequence but automatically reset and ran successfully.
- reactor core isolation cooling (RCIC) system was manually started for vessel level control.

During this event, reactor pressure reached a recorded high of 1105 psig and vessel level reached a low of 117 inches.

Following the scram recovery and as required by procedures, an investigation was conducted into the cause of the scram and any subsequent malfunctions. As noted previously, the sound of an electrical arc was heard when a terminal on cabinet-mounted potentiometer A10P (part of the automatic voltage regulator) was touched. Investigation determined that the terminal could not be made to touch its mounting bracket without applying excessive force but could be moved close enough to cause arcing. Arcing of this terminal caused an electrical discharge of -141 volts dc to ground for the automatic and manual regulators. This potential caused the D1Q and D3Q transistors on the manual regulator board to fail, resulting in loss of voltage regulation and overexcitation of the generator and tripping on power/load unbalance.

Investigation of the initial problem with the automatic regulator following the scram determined that potentiometer A4P (one of nine mounted on the automatic circuit board) was dirty. These nine potentiometers are unsealed and are used for gain and limit circuits. Adjustments to these potentiometers are not recommended by the vendor after initial circuit setup.

SRV J failed to open when given an open signal for pressure control during the scram recovery. An investigation into the failure at Wylie Laboratory determined that the solenoid plunger had stuck in the bonnet tube. This failure mechanism affected the manual and the automatic depressurization system (ADS) mode of operation; however, the safety relief function (overpressure protection) was still operable.

During the course of the scram recovery, the HPCI was placed into service for pressure control. While starting the system, the HPCI turbine tripped on overspeed due to the starting sequence in use. The system auto-reset and operated as required. In initiating the starting sequence of HPCI, the auxiliary oil pump was started prior to initiating an open signal to steam inlet valve F001. As a result of this action, an overspeed trip occurred when oil pressure opened the turbine stop valve (V8) and the governor valve (V9) allowing the startup ramp signal (which is initiated by the V8 limit switch) to complete its ramp cycle prior to the admission of steam pressure. The proper method is to give an open signal to the F001 valve prior to starting the auxiliary oil pump. The HPCI system responded as designed, automatically reset, and was used in pressure control.

As a result of this event, the following corrective actions were taken:

1. The circuit boards for the manual and automatic voltage regulators were replaced.

2. A review of the Alterex excitation system was done in an effort to optimize reliability of this system.

3. SRV J solenoid was replaced and the valve was restored to service.

4. Operator training had been conducted prior to the scram on the correct sequence for HPCI manual initiation due to recognition of the overspeed possibility. The operator who started HPCI had not completed the training, which has now been completed. In addition, an "operator aid" has been established on the control board to provide proper guidance to the operator.

The Licensee determined that this event would not have been more severe under other reasonable and credible alternative conditions.

1.5 <u>Water Intrusion into Instrument Air System at Fort Calhoun</u>

At about 10:45 a.m. on July 6, 1987, at the Fort Calhoun Station* during a surveillance test of the diesel generator room dry pipe sprinkler system, river water entered the instrument air system from the fire protection system.

Evaluation of this event has shown that it occurred as a result of two factors:

1. Instrument air check valves IA-575 and IA-576 were prevented from closing by foreign material.

2. The operator performing the test failed to properly reset the dry pipe valve as a result of inadequate procedures and inadequate training on the unique dry pipe system. The air maintenance device was bypassed, thus removing another check valve and orifice that could have prevented or restricted flow of water into the air system.

In 1985, the fire protection deluge system for the diesel generator rooms at Fort Calhoun was converted from a wet-pipe to a dry-pipe system in order to eliminate freezing problems during winter operation of the diesels.

Instrument air was supplied to the dry pipe valve, FP-513, through two check valves (IA-575 and IA-576) and an air maintenance device in order to hold the valve clapper in the closed position. When the system is activated, (for either fire protection or testing) the air pressure is rapidly depleted and the clapper opens, supplying fire protection water to the deluge headers. Following actuation of the dry pipe valve, it must be manually reset by removing an access cover and relatching the clapper in the closed position. During the reset process, as performed, a flow path existed through FP-514, FP-513, IA-576, IA-575 and IA-569. The fire protection system pressure is about 30 psi greater than instrument air pressure. Thus, water flowed into the instrument air system.

The operator noted that the air-side and water-side pressure gauges (PI-6515 and PI-6516) both indicated pressure in the fire main. He knew that this was not possible if the clapper valve was properly reset. He then closed FP-514, isolating the water flow, and informed the shift supervisor. It is estimated that about 10 to 50 gallons of river water were introduced into the instrument air system during the few minutes this flow path existed.

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*Fort Calhoun is a 478 MWe (net) MDC Combustion Engineering PWR located 19 miles north of Omaha, Nebraska and is operated by the Omaha Public Power District.

Several equipment problems occurred over the next hour as a result of the water intrusion:

1. The bubbler-based level indicator for the diesel generator fuel oil storage tank failed high. An alternate means of level indication was initiated.

2. HCV-485, the closed cooling water outlet valve from shutdown cooling heat exchanger AC-4B opened.

3. Water was observed at the demineralized water makeup flow controller to the boric acid system.

Several actions were completed to return both the instrument air and the fire protection systems to full functional status:

1. Check valves IA-575 and IA-576 were cleaned, tested, and returned to service.

2. The dry pipe valve was properly reset.

3. Plant personnel conducted blowdowns to remove water from the instrument air system.

4. Personnel were assigned to evaluate and define what further actions were required.

The immediate blowdown program demonstrated that the water was confined to the lower two levels of the auxiliary building, below elevation 1025 feet. No water was found in the turbine building or the intake structure. No water was introduced into the containment building, since the instrument air penetration is above elevation 1025 feet. By the end of the work day (July 6), it was believed that substantially all water had been removed from the instrument air system.

As a result of Item 4. above, a detailed and documented blowdown of the systems was initiated on July 9. 515 individual components were included in the scope of the blowdown, and all safety-related air accumulators below elevation 1025 feet were drained, (except for the diesel generator radiator exhaust damper accumulators, as discussed later). Water was found in less than 10% of the components. As much as possible, valves and other components were cycled following blowdown to verify their operability. The blowdown program was repeated in August 1937 for components which exhibited water intrusion during the July blowdown. Eight components on four risers along with the post accident sampling system (PASS) showed moisture during this second blowdown, and were scheduled to be checked again in September.

Diesel generator No. 2 tripped on high coolant temperature during a surveillance test on September 23, 1987. The most probable cause was the failure of the radiator exhaust dampers to open fully. The pilot valve orifice was found to be restricted by foreign material, most likely resulting from the interaction of water, O-ring lubricant, and other materials. The accumulator was 50% full of water.

The Licensee placed heavy emphasis on removing the water from the instrument air system. In retrospect, the potential safety significance of the event was not sufficiently evaluated at the time of its occurrence. Further evaluation was performed in order to assess the potential safety-significance of the event. The event should have been reported as required by 10 CFR 50.72 and 50.73 and plant shutdown initiated per technical specifications.

In addition, it was concluded that a Notification of Unusual Event should have been declared in accordance with the emergency plan. The licensee review concluded that critical safety functions would have been maintained if a design basis accident had occurred coincidentally with the water intrusion event. One of the corrective actions was to ensure that operational events are promptly evaluated for safety significance.

As a result of this event, a fine of $175,000 was levied against the licensee for:

1. Providing an inadequate procedure for testing of the check valves and for loss of the instrument air system.

2. Providing an inadequate 10 CFR 50.59 evaluation for testing of the fire system deluge valve.

3. Failing to make a Notification of Unusual Event and to report the event in accordance with 10 CFR 50.72 and 50.73.

4. Failure of the diesel generator #2 cooling system exhaust dampers resulting in the shutdown of the EDG.

1.6 Main Steam Isolation Valves Open Without Trip Power Available at Point Beach Unit 2

During a startup of Point Beach Unit 2* on August 18, 1987, both main steam isolation valves (MSIVs) were discovered to be without dc control power needed to trip (close) the valves. The reactor was at 2% power for about five hours before the condition was discovered. Upon discovery, the operator immediately restored control power to the valves thereby returning the trip circuitry to an operable condition. No other safety systems are fed from this power supply. The cause of the MSIVs being out of service was personnel error. The power to the solenoid valves was not restored correctly after maintenance.

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*Point Beach Unit 2 is a 497 MWe (net) MDC Westinghouse PWR located 15 miles north of Manitowoc, Wisconsin and is operated by Wisconsin Electric Power.

On the previous day, August 17, Unit 2 was in hot shutdown following a trip which occurred on August 16. The main steam isolation valves were manually shut after the trip to facilitate repairs to three low pressure turbine rupture discs which ruptured during the transient following the trip.

Following repairs to the rupture discs and verification of valve operability, the MSIVs were left open. Later in the morning of August 17, it was decided to inspect the internals of the turbine and a moisture separator reheater. For reasons of personnel safety, the MSIVs were closed and safety tagged. The tags were placed on the instrument air isolation valve to each MSIV and on the dc control power breakers (in the control room) which supply power to the instrument air isolation valve supply and vent solenoids.

After the work was completed, the reactor was released for criticality. By about 9:38 p.m., the reactor was critical with the MSIVs closed. Between 9:38 p.m. and 10:30 p.m., it was intended that the MSIVs be returned to service by clearing the safety tags. Two of the tags were inadvertently not removed. These tags called for the circuit breakers which supply dc control power to the MSIV trip solenoid valves to be in the open position. Without dc control power, the MSIVs can be opened but can not be closed with either an automatic or manual signal.

At about 10:30 p.m., procedures for low power operation were started. The first step required that the applicable portions of OP-13A, "Secondary System Startup and Shutdown" be completed. OP-13A has a step that requires the MSIVs to be opened and cycled, thereby verifying the valve operation. Since the MSIVs had been cycled earlier prior to the maintenance inspection, operations personnel decided that the OP-13A requirement to cycle the MSIVs had already been met. The cycling was therefore not performed and the failure to clear all the safety tags was not identified at that time. At about 11:05 p.m., when the MSIVs were opened, it was not known that the trip circuits for the MSIVs were inoperable because the control power breakers were open.

Some time between 3:30 a.m. and 4:00 a.m. on August 18, Operations personnel discovered the red tags on the dc control power supply circuit breakers for the MSIV trip solenoid valves. After determining that the red tags should have been removed, the tags were lifted and the breakers were closed, making the MSIV trip circuits operable.

After such an incident, the normal course of action would have been to call a superintendent to perform a 10 CFR 50.72 reportability evaluation. 10 CFR 50.72 reportability was not considered by the operator who discovered the condition, so he did not make a call. He did assume a License Event Report (LER) would be required and he initiated a nonconformance report (NCR) on the event. The NCR was issued the afternoon of August 18.

The operator who found the breakers open between 3:30 a.m. and 4:00 a.m. (on August 18) sent a written note to the operator responsible for clearing the safety tags. But he was not scheduled to work until 3:00 p.m. that day. Between 3:00 p.m. and 11:00 p.m., the operator who made the tagging error received the note and generated an NCR. The NCR was sent to a staff reviewer in the normal plant mail. The NCR was received by the reviewer the afternoon of August 19. The NCR did not clearly state that the MSIVs were inoperable for the period of time that they were open with red tags on the breakers. A review of procedure OP-13A led the reviewer, who thought that the breakers may have been closed instead of open, to mistakenly conclude that the valves had been cycled and were, in fact, operable at the time the red tag problem was found. The staff reviewer determined it was necessary to talk directly with the person who identified the situation. The operator was still assigned to the 11:00 p.m. to 7:00 a.m. shift so the staff reviewer decided to talk with him the morning of August 20.

On August 20, the operators involved in the incident were interviewed and it was determined that, in fact, the breakers for the control power were open and that the MSIVs were inoperable with the reactor at two percent power. The decision was then made to notify the NRC duty officer of a probable one hour 10 CFR 50.72 report. Subsequent calculations verified that for the conditions of the plant at the time, the plant was bounded by the design basis.

Initially the "red phone" call was conservatively made as a one hour notification. It was assumed that the unit was in a condition that was outside the design basis of the plant, but subsequent analysis determined this assumption to be overly conservative.

This incident was a result of personnel errors. First, safety tagging was inadequate in that the tag location sheet did not clearly indicate the location of all tags which had been placed. Second, the tags were cleared in an inappropriate manner. The duty operating supervisor (DOS) asked the auxiliary building auxiliary operator (AO) to clear the tags on the MSIVs. The AO cleared two tags from the MSIV instrument air supply, reset the solenoids and told the DOS he had cleared the tags but did not specify which ones or how many. The DOS, with permission from the AO, signed the danger tag location sheet indicating clearance for all four tags, including the two on the dc control power breakers. He thought the tags were located near the MSIVs and that the AO had cleared them (the tag locations were not clear on the tagging sheet). The tagging was then reviewed and cleared by the DSS. Third, because the MSIVs had been cycled the same day, the supervisors on the next shift determined that it was not necessary to completely perform the procedure step which opened and cycled the MSIVs.

The cause of the delayed 10 CFR 50.72 reporting was the failure of the operator to make proper notifications to plant management when the condition was discovered.

A safety analysis was performed to evaluate the effect of the unavailability of the MSIVs on plant safety analyses. The transients of concern are main steam line break (MSLB) and steam generator tube rupture (SGTR).

The main concern in the MSLB accident analysis is the reactivity excursion caused by excessive cooldown of the primary coolant. The Final Safety Analysis Report (FSAR) assumes that the MSIVs will close within 5 seconds to limit the loss of secondary coolant from the "intact" steam generator. The plant design is such that a break anywhere in the steam line can be isolated by operation of either MSIV or the non-return check valves located downstream of the MSIVs. Between the steam generator and its associated MSIV is a flow restricting orifice which also limits flow during a steam line break occurring downstream of the orifice. The worst case break that is analyzed in the FSAR is the MSLB upstream of the flow restrictor.

Based upon the actual plant conditions during the event, it was concluded that the unavailability of the MSIVs during an MSLB was bounded by the worst case FSAR analysis with respect to an overcooling transient and its associated possible reactivity excursion. It should also be noted that experience with the MSIVs at Point Beach indicates that, with the high steam flow that occurs with a steam line break, it is likely that the MSIV would "wipe in" and close of its own accord.

The steam generator tube rupture (SGTR) accident analysis involves the leakage of reactor coolant through a steam generator tube to the secondary side of the steam generator. Radioactivity could then be released to the environment through the condenser downstream of the MSIVs, through the atmospheric steam dump valves, or through the steam generator safety valves upstream of the MSIVs. Although the FSAR analysis assumes that the operator will attempt to isolate the steam generator by closing the MSIVs or the turbine stop valves, failure of an MSIV is assumed under these conditions.

It should also be noted that failure of both MSIVs to fulfill their design function can be mitigated by the use of emergency operating procedure ECA-2.1, "Uncontrolled Depressurization of Both Steam Generators".

The Licensee therefore concluded that the condition of Point Beach during this event did not pose a health or safety hazard to plant personnel or the general public.

The immediate corrective action to restore the functional operation of the MSIVs was to properly clear the safety tags and close the breakers for dc control power to the MSIV isolation and vent solenoid valves.

A modification was initiated to alarm the loss of dc control power to the MSIVs in the control room. This modification should reduce the probability of this condition occurring in the future.

The personnel involved in the event were counselled on the necessity of adherence to appropriate work practices, the proper use of procedures, and the need to contact appropriate personnel in situations having a potential for reportability.

There were several personnel errors identified during investigation of the event. The proposed corrective actions were to address the areas of concern. These included red tag procedure changes, changes in philosophy of procedure use (including signoff) and resultant training.

A fine of $25,000 was imposed on Wisconsin Electric Power Company due to their failure to have any method of steam line isolation operable and the failure to report the event to the NRC within four hours.

1.7 Inoperable Essential Service Water System at Callaway

On August 8, 1987, at 5:10 a.m. at the Callaway* nuclear power plant, during a containment cooling fan test at 100% power, utility operators discovered essential service water (ESW) train B isolation valve, EF-V-0117, partially shut. Train B was declared inoperable, the valve was opened, and train B was again operable at about 2:30 p.m. An evaluation concluded that total train B flow with this restriction was less than specified by design. This condition had existed since May, 1984. Conflicting valve position indicators had were noted on a Work Request (WR) dated May 14, 1984. Whenever train A was removed from service for testing, both ESW trains were technically inoperable.

This event was due to failure of utility personnel to recognize the effect of false valve indication on ESW operability. This resulted in low work priority placed on repairing the problem. The cause of the delay in discovering the flow problem was failure of utility personnel to compare total flow to preoperational test flows when baselining the pumps in 1984 and again in February 1987.

On May 11, 1984, prior to receipt of the plant operating license, utility personnel replaced the manual actuator on ESW train B valve EF-V-0117 because the housing was cracked. Upon completion of the work, the actuator was tested for proper operation.

On May 14, 1984, it was observed that the valve position indicators conflicted and a second WR was written, but it was voided on September 9, 1986, apparently due to a duplication of work with a third WR. The third WR (originated June 10, 1986) arranged for an inspection of EF-V-0117 to assist in determining the root cause of an actuator shaft failure in a similar valve.

Completion of the inspection would require a retest involving verification of position indication. Thus it was concluded that performance of the third WR would also correct the problem identified in the second WR. The work description in the third WR had not been modified to include checking the position indication. The third WR was voided on September 10, 1986 when a later decision was made not to inspect EF-V-0117 due to vendor involvement in root cause evaluation of a similar valve actuator shaft failure. The review by planning and engineering personnel failed to note the revised work scope. Consequently, the problem noted on the second WR went unresolved.

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*Callaway is a 1171 MWe (net) MDC Westinghouse PWR located 10 miles southeast of Fulton, Missouri, and is operated by Union Electric.

On August 15, 1987, utility personnel were verifying ESW valve lineups in order to determine the cause of a low differential pressure reading on the annubar flow element on the train B containment coolers. The low differential pressure was observed during performance of a surveillance test required by plant technical specifications which state:

> "Each group of containment cooling fans shall be demonstrated OPERABLE: At least once per 31 days by verifying a cooling water flow rate of greater than or equal to 2200 gpm to each cooler group."

During this verification, it was discovered that EF-V-0117 was partially shut. After further troubleshooting, ESW train B was declared inoperable at 10:15 a.m. The valve was opened and verified open by stem position and flow indication. ESW train B was declared operable again at about 2:30 p.m.

Utility personnel did not recognize the restricted flow condition on train B before August 15, 1987, because the existing ESW pump surveillance test provided no indication of a problem with pump performance. The surveillance procedure for the pump did not require ESW flow verification. The utility locked valve program was intended to assure adequate flow when pump output was acceptable. The locked valve program verification was performed as required but did not identify errors in position indication for this valve.

On August 20, n engineering evaluation concluded that ESW train B was inoperable on August 15, with EF-V-0117 partially closed. The resultant total ESW train B flow was about 11,000 gpm - which does not meet the Final Safety Analysis Report (FSAR) design value of 13,594 gpm for train B.

In summary, ESW train B flow had been less than specified by the FSAR since 1984. Train A had been routinely removed from service for surveillance testing and maintenance since 1984. Therefore, both ESW trains were simultaneously rendered inoperable.

The root cause of this event was the failure of utility personnel to recognize the effect of faulty valve indication on ESW system operability and the resultant low priority placed on repair. When the plant technical specifications were approved and issued later in June 1984, a review of open WRs failed to identify the condition as an operability restraint. This resulted from a failure to ensure that work requests were was performed in a timely manner.

The following addresses the root cause of this problem being undetected until August 1987. Since the ASME Section XI* baseline was established close to the completion of the system preoperational test, results of the baseline total flow value for the ASME pump and valve tests were not compared to total flow established during the preoperational test. Although methods used to establish this baseline were correct per the ASME code, a comparison would

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*American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI, Rules for Inservice Inspection of Nuclear Power Plant Components.

have discovered this deviation. When the ESW pump was re-baselined in February 1987 (to evaluate apparent pump degradation per ASME Section XI), only pump perform nce was evaluated and no pump degradation was detected. If total system performance had been evaluated and compared to system design, the deviation would have been discovered.

Corrective actions included:

1. The valve actuator was repaired during the second refueling outage.

2. The failure of utility personnel to initially place proper priority on valve indicator work was considered an isolated case. To provide additional assurance, a review of voided and open WRs on selected systems was performed. This review ensured operability concerns had been properly identified and prioritized. In addition, the review ensured that WRs had not been voided without work completion or appropriate follow-up action.

3. The WR control procedure now requires the reason for voiding the WR and the name of the person voiding the WR. As an additional enhancement, the procedure was revised to require that the entire scope of work be transferred from a voided WR to any current WR which implements previously uncompleted work.

4. Engineering personnel involved in voiding the WRs were counseled. It was re-emphasized that thorough research must be done prior to authorizing the voiding of any WR. Engineers involved with ASME Section XI evaluations were reminded to consider the effect on the total system when re-establishing pump baselines.

5. Methods for verification of valve position were considered appropriate and no further action was deemed necessary. However, proper assignment of priority of WRs should assure valve position indicators are more reliable.

Bechtel Corporation conducted an analysis to determine if 11,000 gpm is an acceptable ESW train B flow rate. They performed three evaluations to determine if, during a loss of coolant accident (LOCA) while EF-V-0117 was partially closed and ESW train A out of service, there would have been sufficient safety margins to mitigate the consequences of the LOCA. The three evaluations and conclusions are as follows:

1. Cooling tower performance was evaluated using the LOCA heat load and the critical meteorological conditions established in the plant design. A flowrate of 5,500 gallons per minute per cell (11,000 gpm total) was assumed. It was concluded that the maximum temperature at the ESW pump intake would be less than 90 °F. This value is 5 °F below the design intake temperature of 95 °F which is the maximum pond outlet temperature allowed during the 30-day minimum heat transfer period.

2. The performance of each component cooled by ESW was evaluated at 80% design flow and reduced inlet water temperature. Pond performance that predicts a maximum 90 °F ESW temperature was considered. It was concluded that each ESW-serviced component would be capable of performing its design function with the given conditions.

3. The effect on the containment was evaluated for the component conditions analyzed under item 2 above. The results indicated that the peak LOCA pressure would increase from 47.3 psig to 47.8 psig and peak main steam line break pressure would increase from 48.1 psig to 49.4 psig. Although slightly higher, these values are well below 60 psig, which is the design pressure of the containment.

Based on these evaluations the Licensee determined that this event posed no threat to the health and safety of the public or to plant operators.

A fine of $25,000 was impose on the utility for failure to promptly identify a condition adverse to quality.

1.8 References

(1.1) 1. Virginia Electric & Power, Docket 50-338, Licensee Event Report 87-017, July 15, 1987.

2. NRC Augmented Inspection Team Reports 50-338/87-24 and 50-339/87-24, August 28, 1987.

3. NRC Safety Evaluation Accepting Utility Responses to Steam Generator Tube Rupture on July 15, 1987, December 11, 1987.

4. Virginia Electric Power, "North Anna 1 July 15, 1987, Steam Generator Tube Rupture Event Report", Rev. 2, February 12, 1988.

5. NRC Information Notice No. 87-60, "Depressurization of Reactor Coolant Systems in Pressurized Water Reactors", December 4, 1987.

(1.2) 6. Baltimore Gas & Electric, Docket 50-317, Licensee Event Report 87-012, July 23, 1987.

(1.3) 7. Consumers Power, Docket 50-255; Licensee Event Report 87-024, July 14, 1987.

(1.4) 8. Carolina Power & Light, Docket 50-325; Licensee Event Report 87-019, July 1, 1987.

(1.5) 9. Omaha Public Power District, Docket 50-285; Licensee Event Report 87-033, July 6, 1987.

10. NRC Region IV Inspection Report, 50-285/87-30, December 3, 1987.

(1.6) 11. Wisconsin Electric Power, Docket 50-301; Licensee Event Report 87-003, August 8, 1987.

12. NRC Region III Inspection Report, 50-301/87-16, September 16, 1987.

(1.7) 13. Union Electric, Docket 50-483; Licensee Event Report 87-018, August 15, 1987.

14. NRC Region III Inspection Report, 50-483/87-28, September 25, 1987.

These referenced documents are available in the NRC Public Document Room at 1717 H. Street, N.W., Washington, DC 20555, for public inspection and/or copying.

2.0 EXCERPTS OF SELECTED LICENSEE EVENT REPORTS

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

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

2.1 Ice Buildup in the Ice Condenser due to Sublimation

D. C. Cook Unit 1; Docket 50-315; LER 87-013; Westinghouse PWR

On July 1 and 2, 1987, while D. C. Cook Unit 1 was in cold shutdown, flow passage inspection of the ice condenser revealed frost and ice buildup greater than 3/8 inch on the lattice frames in 124 flow passages in seven of the 24 ice condenser bays. There are a total of 3072 flow passages in the ice condenser. Subsequent inspection indicated that there was also frost and ice formation between the walls and ice baskets adjacent to the walls.

The plant technical specifications limit frost or ice buildup in flow passages to a nominal thickness of 3/8 inch. Buildup exceeding this limit in two or more flow passages per bay is evidence of abnormal degradation. Though the evaluation concluded that the degradation was not serious, a voluntary Licensee Event Report (LER) was considered appropriate since some degradation was identified.

Actions taken included defrosting the ice condenser and an investigation of the cause. The investigation, aided by a previous Westinghouse evaluation, indicated that there was no safety concern. The ice condenser remained in a configuration in which it could have performed its intended safety function.

The plant technical specifications require that the ice condenser be determined operable at least once every nine months via visual inspection of at least two flow passages per bay. Accumulation of frost or ice on flow passages between ice baskets, past lattice frames, through the intermediate and top deck floor grating, or past the lower inlet plenum support structure and turning vanes is restricted to a nominal thickness of 3/8 inch. If one flow passage per bay is found to have an accumulation of frost or ice greater than this thickness, a representative sample of 20 additional flow passages from the same bay must be visually inspected. If these additional flow passages are found acceptable, the surveillance program may proceed, considering the single deficiency as unique and acceptable.

A subsequent partial inspection also revealed that ice had formed in the area between the containment wall and the row 1 baskets. It was also believed that there was additional ice formation in the area between the crane wall and row nine ice condenser baskets. This is similar to event described in LER 50-316/87-002.

The ice made it more difficult to extract the required number of baskets for weighing. However, an earlier Westinghouse evaluation of the condition at Unit 2 indicated that such ice is not unexpected and is not significant with respect to safety.

During the prior surveillance interval, several of the 60 air handling units (AHUs) used to maintain ice condenser temperature had been intermittently inoperable for maintenance or repair. However, it was concluded that the inoperability of the AHUs did not significantly contribute to the frost and ice formation.

It is believed that sublimation of ice or high humidity in the containment could have contributed to the problem. The Westinghouse evaluation indicated that lattice frost and ice formation of up to 20% of the total flow passage area could be present without peak containment pressure exceeding design limits during a postulated accident. Since the frost and ice buildup identified in Bays 1, 4, 13, 18, 19, 22 and 24 constitutes a total flow blockage area less than the 20% limit, the Licensee determined that the situation is bounded by the Westinghouse evaluation.

The Licensees evaluation indicated that the amount of flow blockage due to frost and ice buildup noted in the ice condenser can be tolerated without adversely affecting the ice condenser function during a loss of coolant accident.

Based on the above information and the Westinghouse evaluation, it was concluded that the abnormal degradation event did not constitute an unreviewed safety question as defined in 10CFR50.59(a)(2), nor did it adversely impact health and safety.

The corrective action was to defrost the ice condenser, including manual scraping of the ice.

2.2 Reactor Trip Breaker Failed to Open Due to Mechanical Failure

McGuire Unit 2; Docket 50-370; LER 87-009; Westinghouse PWR

On July 2, 1987, during the performance of the control rod drop timing tests, plant personnel detected smoke in the area of the reactor trip switchgear. The control room was notified and operators manually tripped the reactor trip breakers (RTBs). Control room status lights indicated that both breakers had opened, though investigation revealed RTB 2 to be closed. The breaker could not be opened locally until an attempt was made to manually tension the breaker closure spring. The operators were not holding the feedwater isolation reset button when the breaker did open, so a train B feedwater isolation occurred, but it did not cause any adverse effects.

Upon investigation of the cause of the smoke, it was determined that the Westinghouse DS-416 RTB, installed in the 2RTB cubicle, was in the closed position. Operators made several unsuccessful attempts to trip the breaker. When an attempt was made to manually tension the breaker closure springs, the breaker opened. The breaker was removed from its cubicle for testing to determine the reason it did not open. A bypass RTB was removed from Unit 1 1BYB cubicle and temporarily installed in the vacant Unit 2 2RTB cubicle to complete the rod drop timing test. The control room indicating lights for 2RTB cubicle have functioned properly during all subsequent tests.

The failure of the breaker was classified as a manufacturing defect which caused failure of a weld inside the breaker. The investigation revealed that the breaker failed to automatically open due to mechanical binding. A failed weld and worn components in the breaker closure mechanism were suspected of causing the binding, but nothing conclusive was found during the investigation

to pinpoint the cause. The breaker underwent further inspection and testing at Westinghouse to determine the cause of the binding.
An investigation into the cause of the apparent erroneous breaker position indicator revealed all circuits functioning properly. No abnormalities were discovered which could have caused an open indication when the breaker was still in the closed position.

There are four identical RTBs for each rod control system. The normal alignment uses two main breakers while two bypass breakers are used to support testing and allow continuous operation of the system during periodic maintenance. Cubicles which house the breakers are labeled as RTA, RTB, BYA, and BYB. The four breakers are arranged in a series-parallel network, which allows a main breaker and the opposite train bypass breaker to be deactivated and isolated for testing or maintenance. These breakers may be moved from cubicle to cubicle as required. The RTBs connect the power from the motor/generator sets to the reactor control rod drive mechanisms.

When either of the two operable breakers open, (which are aligned in series) the power is cut off to the control rod drives thereby releasing the rods and the tripping the reactor.

The McGuire Unit 2 Operating License specifies that all four reactor trip breakers must be tested seven days prior to unit startup and undergo similar testing plus time response testing every 31 days. Every 6 months, the breakers are tested and serviced according to Westinghouse specifications. Maintenance of this type is also performed on all Unit 1 reactor trip breakers, though not required by the Unit 1 license.

The Westinghouse DS-416 air circuit breaker procedure provides for inspection and maintenance of the RTB and the connection hardware inside the breaker cubicle. Tests are performed on the undervoltage (UV) trip solenoid and the shunt trip solenoid to verify proper operation. Also, a force test is performed on the trip bar. The trip bar is rotated when the breaker is tripped by the UV trip solenoid, by the shunt trip solenoid, or by the manual trip lever.

The breaker inspection procedure is performed every 6 months on each breaker. During these inspections, the breaker is normally cycled about 50 times to perform the inspection according to the Westinghouse Maintenance Program Manual for DS-416 RTBs. This procedure was last performed for the train B 2RTB breaker (hereafter called breaker B-4) on December 18, 1986, and no problems were found prior to placing the breaker back in service.

On the night of July 2 the control rod drop tests were being performed. Testing had been completed for shutdown banks A through C. Testing was being concluded on shutdown Bank D and the RTBs were required to be open as directed by the test procedure. Operators opened the breakers and, while holding the feedwater isolation reset buttons as directed by procedure, observed the breaker position lights in the control room change from closed to open. The events recorder indicated that the train A breaker had opened, but unknown to the control room operator, it did not indicate a change from closed to open for the train B 2RTB breaker. However, operators in the control room did observe the illuminated open status indicator light for breaker B-4.

Operators closed the RTBs to allow continuation of the test with shutdown (S/D) bank E control rods. Operators observed the breaker position lights change from open to closed and shortly thereafter, began to withdraw S/D bank E rods. The events recorder again did not show a change of breaker position for breaker B-4. As operators were withdrawing S/D bank E, they noticed the demand counter for this bank was not counting up from zero. The operators notified personnel who were working with them on this test in an adjacent room which contained the RTBs. At the same time, test personnel detected smoke coming from the RTB cabinets. They informed the operators who immediately opened the RTBs and, while holding the feedwater isolation reset buttons, observed the status lights change from closed to open. Unknown to the control room operators, the events recorder again did not indicate that breaker B-4 had opened.

Plant personnel investigated and found that the breaker in 2RTB (B-4) had not tripped and was the source of the smoke. A local (manual) trip of the breaker was then attempted while the feedwater isolation reset button was held down. Since the breaker was smoking, a broom stick handle was employed to push the manual trip lever, but the lever would not move. These manipulations of the local manual trip lever did not open the breaker. In an attempt to cycle the breaker, they began to manually charge the close spring. As the close spring was being tensioned, the breaker opened. Due to the difficulties and a long delay (about 12 minutes) in opening the breaker, operators were not holding the train B feedwater isolation reset button when the breaker finally opened. This resulted in a train B feedwater isolation signal that was generated by the solid state protection system (SSPS). Closure of the condensate feedwater valves under the direction of the feedwater isolation signal did not cause adverse affects. Operators then declared 2RTB inoperable.

Breaker B-4 was removed from the 2RTB cubicle. Operators notified the Shift Technical Advisor (STA) and the Unit 2 Shift Coordinator of the situation. The Shift Coordinator advised operators to contact Generation Station Support (GSS) personnel to determine if the Unit 1 bypass breaker from 1BYB cubicle could be used in the 2RTB cubicle to replace the failed breaker B-4.

A work request was written to investigate and repair the problem with RTB B-4. Operators also implemented the NRC Immediate Notification Requirements procedure, and informed the NRC of the breaker failure and the feedwater isolation (an engineered safety feature actuation) at 1:12 a.m. The Station Manager instructed operators not to withdraw any control rods without his permission.

Plant management discussed the situation with NRC personnel and at 2:10 p.m. on July 3, appropriate permission was given to resume rod drop timing tests with the use of a Unit 1 bypass RTB. At 5:30 p.m. that same day, rod drop timing tests were completed.

GSS began an initial assessment to determine the cause of the failure. The breaker was cycled three times during their inspection. The breaker was closed electrically, and continuity checks of the auxiliary switch contacts in the shunt trip circuit indicated that they were closed. The breaker was then tripped by use of the UV trip attachment and the breaker opened. The breaker was then closed electrically a second time and a trip force test was performed on the trip shaft, but rotation of the shaft did not trip the breaker. This constituted the second failure of the breaker. Repeating what operators had previously done to open the breaker, they began to manually tension the close spring. As soon as the crank shaft (and close cam) began to rotate, the breaker jarred open. The breaker was closed electrically a third time and a second attempt was made to perform a trip force test. On this attempt, the breaker opened successfully. Testing was stopped, and the breaker was quarantined until all personnel concerned with the failure could be present.

On July 7, an NRC Inspection Team arrived on site. Utility, Westinghouse, and NRC personnel met to determine a planned course of action to inspect and test breaker B-4. Meeting attention focused on attempting to preserve any evidence which would show why the breaker failed to open.

Inspection of the breaker mechanism revealed that the weld which connects the center pole lever to the pole shaft had failed. This weld had cracked along its entire length. Only one side of the center pole lever was welded to the pole shaft and was only welded about half way around the pole shaft. Inspection of other pole shaft levers revealed that weld lengths were on the order of 3/8 to 3/4 the circumference of the adjoining pole shaft.

Corresponding abnormal wear marks were found at two different locations in the breaker. An indentation approximately 3/32 inches long was found on the notch of the trip shaft which mated with a small wear mark on the trip latch. Subsequent testing determined that the force required to rotate the trip shaft, allowing the trip latch to pass through the notch on the trip shaft, was within acceptable limits.

The second area of excessive wear was the far left side steel laminate of the four-piece laminated closing cam surface, which contacts the roller on the main drive link. Wear was also found on the right most steel plate of the closing cam, but was not as excessive as the left most plate.

In an attempt to recreate the binding which had twice prevented the breaker from opening, 31 trips of the breaker were performed. Several attempts were made to artificially produce similar binding of the breaker mechanism, but each time the breaker was directed to trip, the breaker opened successfully. Whenever the breaker was closed, inspection revealed that the main drive link top pin, main drive link, roller constraining link, trip latch, and center pole lever (with the broken weld), were able to twist and subsequently bind. All other trip system components did not reveal any abnormal conditions. The collective inspection and testing of the breaker was concluded on Thursday, July 9.

Inspection began on the remaining three Unit 2 RTBs on July 13. During the inspection of the breaker from cubicle 2RTA (breaker B-1), personnel found a questionable weld on the pole shaft lever which operates the auxiliary switch linkage. The inspector performed a liquid dye penetrant test on the weld and discovered what appeared to be a hairline crack in the weld. A force test was performed on the lever arm using a safety factor greater than six. The lever satisfactorily passed the test, and the breaker was cleared for return to service.

Visual inspection of breaker 2RTB (breaker B-2) revealed heavy wear on the left side of the closing cam. The main drive link appeared to be tilted about 30 degrees to the left from the lateral plane. Clearance of the mechanism appeared to be adequate and welds were good. The same type of wear was observed on breaker B-3, where all welds were determined to be acceptable.

Electrical testing performed on the B-4 breaker indicated that all switch and internal wiring were satisfactory except for the burned out shunt trip coil. The shunt trip coil burned out about 2 to 5 minutes after the coil was energized but did not deenergize because the breaker failed to open. This coil is not rated for continuous duty and is normally deenergized by another auxiliary switch as the main breaker contacts open.

The shunt clearing contact opens well before the green (open) light and the events recorder contacts. This indicates that the shunt trip coil could not have burned out if the auxiliary switch contacts for the green light had made contact. Since both the green light and the events recorder operate simultaneously, this would provide recorder data that the breaker did not open. Likewise, the auxiliary switch contacts for the green light could not have made contact to illuminate the green light unless an external wiring problem existed. The external wiring was checked for circuit polarity and determined to be correct in all cases.

Ground circuits on the 125 volt dc battery power system were investigated. A ground was found on the positive side of the dc system but was not inside the breaker compartment. After failed breaker B-4 was replaced with an operable breaker, the replacement breaker was cycled five times in cubicle 2RTB. During this test, all breaker position indicating lights and the breaker itself operated correctly.

The failed RTB B-4 had been thoroughly inspected and tested in December 1986. That inspection found no problems. Since then, breaker B-4 has been cycled successfully. Each time, the breaker performed as required. The device passed the time response tests required every 31 days without exceeding the maximum 150 millisecond opening time limit.

Preliminary investigation did not determine a reason for the breaker to stick closed and fail to open. Three factors which may have contributed to failure of the breaker to open are:

- weld failure,
- manufacturing tolerances of the breaker components and,
- the cumulative effect of the high number of cycles on the breaker.

The actual number of breaker cycles could not be determined to any degree of accuracy since the breaker was retrofitted with a counter after initial installation. Best estimates place the number of cycles above 3000. Closure mechani parts, particularly the closing cam, showed signs of abnormal and excessiv wear, but the exact point of binding, which resulted in the breaker failing open, has not been determined.

Investiga ion of the shunt trip coil determined that it failed sometime after breaker B-4 was cycled at the conclusion of control rod drop timing tests on shutdown bank D; but before rod drop testing was started on shutdown Bank E. The events recorder indicated that the breaker did not open during these attempted breaker cycles and that he shunt trip coil remained continuously energized. The shunt trip coil burned up and shorted to ground and the resultant smoke alerted personnel to the breaker problem.

Investigation into Westinghouse breaker failures, with the assistance of the Nuclear Plant Reliability Data System (NPRDS), revealed failures of DS-416 breakers used in various applications. Primarily, they involved failure to close due to electrical problems in auxiliary switches and external control circuits. However, three failures were associated with broken welds. Two occurrences at other utilities involved weld failures associated with the pole shaft. The third occurrence was associated with the secondary disconnect support bracket.

Unit 2 was in hot standby, and had not been critical for 63 days due to a refueling outage. Control rod drop timing tests were being performed which allowed only one bank of control rods to be withdrawn from the core at any given time. To verify that the rods of the bank being tested have all dropped, both RTBs are opened to ensure that all rods are at the bottom of the core prior to withdrawing another bank. In this incident, one of the RTBs failed to open, but the second (redundant) breaker did open.

The failure of this breaker was discovered due to the smoke which resulted when the shunt trip coil overheated as a result of not being reset after energizing. If the shunt trip coil had not overheated, or if the smoke had not been detected, the time at which the stuck-closed breaker would have been discovered is not certain, assuming the condition which provided the erroneous indication in the control room continued to exist. It should be noted that the maximum time period a breaker could be in an unknown failed condition is 31 days under the surveillance requirements. This condition of one breaker continuously stuck closed would not have affected the timing tests being performed since the redundant operating breaker would have performed the opening function.

Had this incident occurred at 100% power, the redundant RTB would have performed the opening action required to cut power to the control rod drives and tripped the reactor. In a postulated incident where the stuck closed breaker condition previously existed, a failure of the second breaker would involve both RTBs failing to shut down the reactor. This scenario of failure to shut down the reactor is addressed by emergency procedures. If a reactor trip has not occurred, three operator actions would have to be carried out to insert the control rods. First, operators would have to manually insert the control rods. Another operator would have to go to the adjacent room which contains the motor/generator (M/G) sets and open the output breakers that supply power to the motors of the M/G sets. This action could be completed in less than 1 minute. It should be noted that during an actual reactor trip event, operators in the control room will usually first look at the digital rod position indicator lights for confirmation that the rods have dropped after opening the RTBs. Therefore, sufficient capability to trip the reactor would exist at all times.

2.3 Unisolable Reactor Coolant Pressure Boundary Leak Caused By Failure to Identify Defective Seal Weld Made During Pressurizer Repairs

Arkansas Nuclear One, Unit 2; Docket 50-368; LER 87-006; Combustion Engineering PWR

At about 10 a.m. on July 6, 1987, while ANO-2 was at 100% power, health physics and operations personnel entered the ANO-2 containment building to perform surveys and inspections in preparation for maintenance on a steam generator level transmitter which had been exhibiting abnormal indications. While in containment, they performed a general inspection of the building and identified a small leak which appeared to be originating from the bottom of the pressurizer. Due to time limitations, they left the containment and informed plant management of their findings.

At 2:09 p.m. another containment entry was made by health physics, operations, and engineering personnel to identify the specific location of the leak. During this entry it was determined that a small leak was originating from the sleeve collar area on pressurizer heater sleeve Y4. The leak rate, estimated to be about two to three drops per minute, was determined to be an RCS unisolable pressure boundary leak.

An Unusual Event was declared at 3:06 p.m., and unit cooldown was commenced per technical specifications. The unit reached hot standby at 8:00 p.m. and cold shutdown was achieved at 3:43 a.m. the next day. The Unusual Event was terminated upon reaching cold shutdown.

Earlier, on April 24, 1987, plant personnel discovered an unisolable RCS pressure boundary leak originating from a damaged pressurizer heater sleeve on the pressurizer (reported in LER 368-87-003). Subsequent investigation revealed two severely damaged heaters. The design and manufacturing process of Watlow heaters was the root cause of the heater failures. Twenty-three Watlow heaters were removed from the pressurizer as a precaution against future failures. Due to unavailability of a sufficient number of replacement heaters, 15 empty heater sleeves were fitted with temporary heater plugs welded to the sleeves. This work was performed in accordance with an approved design change package.

Combustion Engineering (CE) was contracted to perform the design and installation of the plugs, including all welding by qualified welders and non-destructive examination (NDE) of welds by certified inspectors. Work was performed under the CE quality assurance program. Six new replacement heaters manufactured by General Electric (GE) were also installed in the ANO-2 pressurizer by CE at the same time. This made a total of twenty-one seal welds performed by CE on the pressurizer heater sleeves in May 1987.

After all repairs to the pressurizer had been completed and while electrically re-connecting the heaters, two were found to be electrically shorted. One of these heaters was a new CE unit which had just been installed. The other was an original heater installed during plant construction. Both heaters were removed and temporary heater plugs welded in the heater sleeves. Since CE personnel had already left the site, these repairs were completed by utility personnel. Welding on these plugs was performed by mechanical maintenance personnel and NDE on final welds performed by an on-site contractor qualified to perform NDE.

Upon discovery that the Y4 temporary plug seal weld was leaking, a detailed review of the plant design change package used to perform the welding was initiated. All aspects of plug and heater installation were reviewed - weld records, materials, personnel qualifications and results of NDE performed after final welds were complete. The results of this review generated concerns with respect to the quality of the seal welds performed by CE. A decision was made to inspect additional welds associated with the installation of the plugs and heaters.

NDE of 14 welds done by CE, including the five heater seal welds, was completed on July 8. These tests showed that about 50% of the welds had some type of unacceptable indications. The defects included both rounded (porosity) and linear (crack) indications. Visual inspection of the welds revealed several instances of weld roughness, sharp edges, and apparent discontinuities in the weld material. In addition, measurements of weld material determined that two of the welds had unacceptable geometries, i.e., less than minimum 1/8-inch fillet weld size.

Inspection of two welds completed in May 1987 by utility personnel identified no apparent problems. After a thorough review of the installation of these plugs it was decided that these seal welds were acceptable.

The plant technical specifications state that pressure boundary leakage of any magnitude is unacceptable since it may be indicative of impending gross failure of the pressure boundary. At the time of discovery, the defective seal weld for the Y4 temporary heater plug was leaking at a rate of two to three drops per minute. This small leak created no operational problems. In addition, evaluation of laboratory testing performed on the weld after removal concluded that the leak was caused by a lack of weld metal fusion. This was probably produced at a location where welding was stopped and then restarted. It was concluded that the probability for gross failure of the weld was extremely low.

Another significant factor is the design of the pressurizer heaters. The heaters (in this case the temporary plugs) were inserted into the sleeves and welded to the sleeves. A locking collar secured to a threaded portion of the sleeve covers the heater and seal welded area. Even if catastrophic failure of the weld occurs, ejection of the plug from the sleeve is prevented by the locking collar. Subsequent leakage would be limited by the close tolerances between the plug and collar. Based on these factors, it was concluded that the safety significance of this event was minimal.

The length of time that the leak existed prior to detection is not known. As a result of the repairs to the pressurizer, routine monthly inspection of the containment building, including the lower head area of the pressurizer, have been initiated.

The Y4 and C2 temporary heater plugs installed by CE in May were removed from their sleeves by cutting off above the seal weld taking care not to damage the weld during removal. The plugs, with the intact welds, were visually inspected by utility personnel and then shipped to CE in Windsor, Connecticut for laboratory testing and failure analysis.

The examinations conducted at CE used visual, stereomicroscopic and scanning electron microscope techniques. These inspections revealed a brown stain emanating from about the center of a "ground-out" region of the weld. A dye penetrant test confirmed that this location was the leaking defect. The next approach was to carefully grind into the defect and make observations on an etched plane perpendicular to the leak path. After grinding, a detailed examination of the surface revealed a "cold shut" type of void in the weld metal apparently at a weld stop/start location. Additional grinding was performed and the leak path was examined in a stereomicroscope. Depth was observed to be significant and the bottom of the void could not be visually detected. At this point the sample was sectioned in the axial direction just to one side of the leak path. Careful grinding toward the leak path exposed the entire defect for examination. This view revealed an absence of weld metal fusion. This was determined to be the cause of the leak.

Review of the plant design change package used to install the plugs and heaters during the May 1987 outage revealed that 11 of the 15 temporary heater plug welds performed by CE had unacceptable test results after final welds were completed. Further documentation indicated that all of the unacceptable indications had been removed by grinding the welded areas followed by satisfactory examinations. Repair of welds or removal of weld surface indications by grinding is acceptable per ASME Code, Section III, Class I requirements provided the minimum weld size is maintained. Final visual inspection performed by CE personnel indicated that the welds were satisfactory.

At this time the root cause of this event appears to be related to the failure to identify and correct the discrepancies associated with the welds in their final as-left condition during the May 1987 outage.

Following plant shutdown and cooldown in July, immediate action was directed toward determining the specific location of the leak on the Y4 heater plug. Upon discovery that the leakage was from a temporary heater plug seal weld, actions were initiated to identify the root cause of the defect. CE was contacted and a CE welding engineer who was involved in the May 1987 pressurizer repair was brought on site. Based on the results of extensive reviews of welding records and visual examinations of the leaking seal weld after removal from the vessel, it was concluded that the exact cause of the defect could not be determined without further laboratory testing of the actual weld. Additionally, the investigation created concerns that the Y4 weld failure may not have been an isolated case and that the integrity of all temporary plug welds and heater welds performed during the May 1987 outage was suspect.

After verification of the welding records, and NDE of the two welds which utility personnel had performed during the outage, the scope of future actions was limited to those welds which had been performed by CE personnel. Actions were initiated to remove and redo all seal welds completed by CE during May 1987.

A total of 20 welds were cut out and removed. This included 15 welds associated with temporary heater plugs and five welds used to install new heaters. During removal of the heaters, the heater sheaths were damaged slightly and the heaters could not be reused. The 20 pressurizer heater sleeves were inspected and new plugs were inserted and welded in place. Utility personnel performed all removal and reinstallation.

To insure acceptable final weld quality, several aspects of the repair process were modified from those used by CE during the May repairs. Some of these were:

a. Weld Techniques

1. A different weld filler wire size was utilized. This was done to allow better puddle and bead control by the welder.

2. During the May repair effort, personnel used a variable amperage/current control device to control welder output. This device had to be controlled locally by the person actually doing the welding. Thus accurate control was made difficult due to physical space limitations in the area. Variable welder control was not used on future jobs.

b. Repairs/Grinding Considerations

1. If grinding operations were necessary to remove surface defects indicated by NDE or to improve the visual acceptability of welds, these operations were limited to light buffing or polishing where possible. This method minimized the possibility of "smearing" the weld material over a defect which could preclude detection of the defect during subsequent examination.

2. If "hard" grinding of a weld was necessary to remove a defect, all areas subject to this process were ground to the base material. Therefore, no weld filler material remained in the defect area. Any "hard" ground areas were welded after grinding and then reinspected.

2.4 ESF Actuation From Main Turbine Trip and Feedwater Isolation

Diablo Canyon Unit 2; Docket 50-323; LER 87-015; Westinghouse PWR

At 4:41 a.m. on July 14, 1987, with the unit in power operation during a startup, a main turbine trip, a main feedwater pump trip, a a feedwater isolation valve closure occurred due to steam generator 2 reaching its high-high level setpoint.

The high steam generator level was caused by feedwater control difficulties resulting from mechanical problems with two steam dump valves. These difficulties were further aggravated by a positive moderator temperature coefficient (MTC). Operators promptly reduced reactor power and stabilized the plant.

The immediate corrective actions to prevent recurrence were to repair, adjust and test the steam dump system and to contact other facilities with positive MTC experience for information on operating strategies. These strategies were reviewed with all operators.

Long-term corrective actions included:

- revision of startup procedures to provide more detail for feedwater control on startup,
- identification of systems required to be fully operable,
- provide methods for starting up with a positive MTC and,
- revision of the simulator program to adequately model the characteristics of the core after a core reload if there is a significant difference between the reactor core and the simulator core model.

2.5 Improper Torque Switch Settings for Containment Spray Valve

Oconee Unit 2; Docket 50-270; LER 87-006; Babcock & Wilcox PWR

On July 17, 1987, the plant was at 87% power. Reactor building spray valve 2BS-2 was declared to have been inoperable from September 20, 1986, until July 17, 1987. On that day, engineering calculations first determined that the valve was technically inoperable. Torque switch settings on the valve operator were set too low.

The reactor building spray (RBS) system is designed for long term heat removal following an accident. The system sprays borated water from nozzles at the top of the reactor building. The RBS system consists of two independent trains, each with its own pump, nozzles, and associated valves and piping. Valves 2BS-1 and 2BS-2 serve as throttle valves for the RBS pumps.

c. Inspections of Weld Process and Final Welds

Several different levels of inspection were utilized to monitor the welding process and to verify acceptability of the final welds. These included extensive utility quality control involvement in the actual welding and subsequent NDE; the use of an outside contractor to perform final weld examinations; and independent verification checks by qualified utility welding engineers and plant engineering.

As a result of the Y4 heater plug seal weld leak and other discrepancies, a decision was made to review other repairs made during the May 1987 outage in the location of the X1 and T4 pressurizer heaters. These repairs had consisted of complete removal of the heater sleeves and welding of plugs in the lower pressurizer head. The design change package used for these repairs was reviewed in detail. Emphasis was placed on identification of the extent of quality control involvement and verification during the repair, including acceptability of the results of NDE. Evaluation of the results of this review concluded that there were no potential problems related to the repairs of the X1 and T4 areas. Additionally, the review confirmed extensive involvement by utility quality assurance and quality control personnel in these repairs.

After the repairs to X1 and T4 areas were completed during the May outage, ultrasonic examination (UTE) was performed on both areas to collect baseline data for future examinations. Since the unit was shut down to repair the Y4 seal weld and plant conditions were similar to those established for the UTEs in May, it was decided to repeat the UTE on the X1 and T4 areas during this outage. The UTE of the areas was completed on July 13 and the results indicated no significant differences from those obtained in May.

Following plant heatup on July 16, 1987, a leak test at elevated reactor coolant system (RCS) pressure was conducted as required by the ASME code for repairs of this type. Visual examinations were conducted in the area of the lower pressurizer head with specific inspection of the sleeve collars and areas of seal welds. No leakage was noted as a result of these inspections.

Actions planned as a result of this event included:

1. NDE performed on the seal welds of the temporary heater plugs and heaters after plant shutdown on July 7 established the as-found conditions of these welds. Evaluation of the results of the examination indicated a significant difference between the as-found condition and the final as-left condition of the welds performed by CE in May 1987 as documented in the plant design change package used for the repairs.

2. The monthly containment inspection implemented after the pressurizer repairs in May 1987 will be continued. Such inspections will provide a high confidence level that RCS leakage from the ANO-2 pressurizer or other sources can be identified and necessary corrective action taken.

The system initially takes suction from the borated water storage tank (BWST) through an interconnection with the low pressure injection (LPI) system. As the BWST level is depleted, the RBS suction switches to the containment building emergency sump as the LPI system switches to recirculation.

In 1986, Duke Power Company began a program to verify operability of motor operated valves (MOVs) in response to NRC Bulletin 85-03. Part of the program utilizes the Motor Operated Valve Analysis and Testing System (MOVATS) for testing valve operation. Prior to this, MOVs were generally set up based on calculations by the valve operator manufacturer - Limitorque Corporat on. Limitorque in turn performed the calculations based on the particular valve being used. When the utility program began, it was a combined effort of Design Engineering and Nuclear Maintenance personnel.

The selection of a valve operator for a particular valve is based on the calculated thrust required to open and close the valve. In order to protect the valve and the operator from being overstressed and damaged, torque switches are adjusted on the operator to stop it when a predetermined torque is encountered by the valve or operator during opening and closing. The torque switches are set at some margin above the normal operating torque required to operate the valve. Since greater torque is required to unseat a valve, a switch is provided to electrically bypass the torque switch during initial valve opening travel. Both the torque and bypass switches may be adjusted in the field.

The first step in the operability program was to obtain thrust calculations from Limitorque. Limitorque was first contacted in March of 1986 to provide thrust data for safety-related MOVs. Information for specific valves was requested by the original order number under which the valves were purchased. Valves 3BS-1, 3BS-2 and 2BS-2 for the RBS system were purchased under one order number. Valve 1BS-1, 1BS-2 and 2BS-1 were purchased under a separate order number.

On ..ly 2, 1986, Limitorque requested more information regarding several di..erent valves including the RBS valves. At this time, it was noted that the RBS valves were listed as gate valves. Limitorque requested that Duke Design Engineering insure that the data was accurate. On July 8, 1986, Design Engineering sent to Limitorque a Duke drawing originally obtained from the reactor supplier - Babcock & Wilcox - which listed the valve as a gate valve.

In August 1986, Limitorque sent valve operator data sheets to Design Engineering for the three RBS valves plus other valves. In a cover letter accompanying the data sheets, Limitorque recommended that the information on the valves be verified with the valve manufacturer. Design Engineering subsequently requested data from the valve manufacturer on August 22, 1986.

Torque calculations for the RBS valves were based on factors for gate valves, but Design Engineering determined that the valves were globe valves. This made the thrust calculations inaccurate. Design Engineering had the impression that the Limitorque data was to be used only for reference; and only for comparing the thrust calculations used for original field setup to insure that the valves were operable. Design Engineering sent the data sheets for the RBS valves to Nuclear Maintenance and did not inform them of the mislabelled valves or the incorrect calculations.

When Nuclear Maintenance received the data, it was assumed correct. Upon review, based on the thrust calculations, it was noted that the valve operators appeared to be oversized. However, this was not investigated further. Later in August, Nuclear Maintenance sent work sheets showing the required thrust settings to be used with the MOVATS program to the Instrument and Electrical (I&E) group. The work sheets listed the valves as gate valves.

On September 19, the MOVATS procedure for testing valve 2BS-2 was performed. The procedure requires that the "MOVATS Test Data Sheet" be filled out as much as possible prior to actually testing the valve. Section 1 of the procedure requires information whether the valve is a globe or gate valve. One step was signed off as complete, when in fact, the individual had not completed it - the valve type was left blank. The individual involved stated that he had been using Section 1.0 as a means of verifying his records by letting the MOVATS crew fill in the blanks with "as found" data. At this time, the individual was unaware of how the required thrust for a valve was calculated and did not know that the valve type affected thrust calculations.

MOVATS analysis on 2BS-2 was performed September 20. The torque switches were set based on the calculated thrust and field measurements. These settings were less than the minimum settings later determined in July, 1987. Thus 2BS-2 was considered inoperable from September 20, 1986, until July 17, 1987.

While performing the analysis on 3BS-2, the I&E crew did not fully complete Section 1.0 of the MOVATS procedure. When this procedure was reviewed, Section 1.0 was then completed. At this time it was determined that 2BS-2 was a globe valve, based on plant flow diagrams. Valves 3BS-1 and 3BS-2 were MOVATS tested in a similar fashion on January 23 and March 5, 1987, respectively.

On March 4, Design Engineering received information that had been requested from the valve manufacturer (Aloyco) and forwarded it to Limitorque. During this time, a valve group had been formed in the Design Engineering organization. On May 14, Limitorque sent the corrected thrust calculations using factors for globe valves. At no time, was Nuclear Maintenance aware that the data for 2BS-2, 3BS-1 and 3BS-2 were in error. As part of an ongoing study of valve operability, Design Engineering requested that Nuclear Maintenance obtain actual field data on motor operated valves.

On July 14, while reviewing the valve data, Nuclear Maintenance noted that the thrust calculations for valves 2BS-2 and 2BS-1 were significantly different even though they were the same type valve. Further investigation revealed that 2BS-2 was misidentified as a gate valve. The next day, Nuclear Maintenance informed Design Engineering that valves 2BS-2, 3BS-1 and 3BS-2 were all misidentified and requested an analysis to determine operability.

On July 17, Design Engineering determined that valve 2BS-2 was technically inoperable while valves 3BS-1 and 3BS-2 could be considered operable. The Unit 3 valves were deemed operable because, based on MOVATS data, the torque bypass switch would bypass the torque switch until the valve was completely off its seat.

Valve 2BS-2 had the same bypass; however it disengaged four milliseconds after the valve was off its seat. Design Engineering determined that four milliseconds was insufficient to assure operability. The 3BS valve time intervals were about 10 times higher. Design Engineering had determined how high the torque switch setting had to be for the valve to be operable. I&E personnel adjusted the 2BS-2 torque switch to the recommended setting on July 17; thereby making the valve operable.

The Licensee concluded that the root cause of this incident was the failure of Design Engineering to inform Nuclear Maintenance of errors in the thrust calculations. Design Engineering had the impression that the Limitorque-supplied data was for reference only and was not to be used for valve setup. This was in error, as Nuclear Maintenance forwarded the calculations to the plant after only verifying the calculations. It was also concluded that the vendor-supplied data contributed to the incident because it was inaccurate.

It was noted during the incident investigation that three opportunities existed that could have prevented or mitigated the incident:

1) The first occurred in 1972 when two approved B&W drawings erroneously showed that valves 3BS-1, 3BS-2 and 2BS-2 were gate valves. One of the drawings showed the outside dimensions of the Limitorque operator used on the valve while the other showed a wiring diagram for the operator. On both drawings, a table of valve data in the margin of the drawing listed the valve as a gate valve. Because Duke Power Company purchased the operators and valves from Limitorque through B&W, it was concluded that the errors on the drawings are related to the errors in the Limitorque files. Had this discrepancy been recognized and corrected on the drawings, the Limitorque files would have been corrected.

2) The second chance occurred when Nuclear Maintenance noted that the operator for 2BS-2 appeared to be oversized for the valve. Had the anomaly been investigated, the calculation errors may have been discovered. However, it was not considered significant at the time to warrant immediate investigation. The investigation noted other instances where Limitorque data initially appeared inconsistent (but later verified correct). Thus it cannot be concluded that Nuclear Maintenance acted in error by not performing an immediate investigation.

3) The third opportunity lay with the I&E Engineer who reviewed the data and completed the MOVATS procedure. Had he properly completed the procedure, he may have noticed that 2BS-2 was misidentified as a gate valve. However, when 2BS-2 was tested in September, he had not seen the equations for calculating thrust and was unaware that the

calculations were dependent on valve classification. When Nuclear Maintenance received the data sheets for 3BS-1 and 3BS-2, they included the equations. The I&E engineer could have recognized the error if he had noticed the mislabelling of the valve while filling in the MOVATS procedure and that there were different calculation factors for globe and gate valves.

Corrective actions included:

- Increasing torque switch setting on 2BS-2 to 3.0.

- Informing Limitorque that 2BS-2, 3BS-1 and 3BS-2 were globe valves.

- Reviewing bypass switch setting procedures on motor operated globe valves.

- performing MOVATS test on valves 3BS-1 and 3BS-2 and change torque switches to a setting of 3.0.

For post accident long-term cooling, the RBS system is designed to operate redundantly with the reactor building cooling units (RBCUs). Either system is capable of supplying 100% of the required heat removal calculated in the Final Safety Analysis Report (FSAR).

Under the most severe pressurization accident, the FSAR states that if both RBS spray trains are out of service, and all RBCUs are inoperable, the pressure in the reactor building would remain below design pressure. The cooling capacity of either train of RBS; the RBCUs; or a combination of the two is required to protect containment equipment under long term accident conditions.

It should be noted that valve 2BS-2 was rendered inoperable by a switch setting which was designed to prevent overstressing of the component. At no time was there a component failure associated with 2BS-2 inoperability. 2BS-2 is located outside containment building in a penetration room. In case of an accident, the penetration room could be entered to adjust the torque switch.

The Licensee concluded that the health and safety of the public were not affected by this event.

2.6 Possible Inadequate Containment Cooling After A Non-LOCA Event

Sequoyah Unit 1; Docket 50-327; LER 87-047; Westinghouse PWR

On July 22, 1987, with units 1 and 2 in cold shutdown, it was determined that long-term containment temperatures following a non-loss of coolant accident (LOCA) were developed without considering the reactor coolant system (RCS) as a major heat source.

For events inside containment, a LOCA was assumed to be the bounding condition for developing the long-term temperature profile. This assumption was used to develop the postaccident temperature profiles for environmental qualification (EQ) of components located inside containment. However, the LOCA analysis assumes that the plant will be taken to cold shutdown following an accident. For all other events, the safe shutdown condition of the plant is hot standby. This is because a single failure of the residual heat removal system could prevent entry into cooler operating modes. Thus, with the plant in hot standby above 350 °F, the RCS will act as a heat source. This could cause the long-term containment temperatures to rise above the present EQ temperatures.

The plant is also designed to be maintained in hot standby for events occurring outside containment. No analysis had been performed to verify that temperatures inside containment remain within the present EQ temperature profile for events occurring outside containment. Previously, it was assumed that normal containment cooling would be available. However, the cooling equipment that is assumed to function is not safety-grade. Therefore, it cannot be assumed to provide a safety-related function.

The cause of this condition was identified as a design deficiency in the development of long-term containment temperatures following a non-LOCA event. Previously, it was assumed that a LOCA was bounding for developing the long-term temperature profile of the containment. However, for non-LOCA events, a computer code determined that after several hours, the temperature could rise above that for the LOCA case. Thus, the EQ temperature profiles for equipment inside containment could be potentially nonconservative.

Sequoyah was shut down in August 1985; therefore there has been no violation of environmental qualification of equipment. If the plant had experienced a non-LOCA event at power, the postulated conditions could have resulted. The postaccident temperatures inside containment could rise above the present EQ temperature profile. However, the present normal containment cooling equipment is assumed not to function in the accident analysis.

The lower containment coolers were originally qualified as safety class 2B coolers. The quality of this equipment is such it could be upgraded to safety-related requirements. The probability exists that even though the normal containment cooling components were not relied upon for the accident analysis, sufficient cooling would have been available to prevent temperatures from rising above the present EQ temperature profile.

To resolve the potential problem, TVA decided to upgrade the lower compartment coolers to meet safety grade requirements. The lower compartment coolers have sufficient heat removal capability to remain within the present EQ temperature profiles for events both inside and outside containment.

2.7 Inadequate Communication Between Design Organizations Results in Unanalyzed Conditions

Sequoyah Unit 1; Docket 50-327; LER 87-044; Westinghouse PWR

Flooding effects of moderate energy line breaks (MELB)[*] were not adequately analyzed due to inadequate communication between the pipe break analyst and the system engineers responsible for performing the analysis. The requirement for an evaluation for flooding effects was not specifically identified in the pipe break analysis report. As a result, the lead civil design organization only evaluated jet and temperature affects of MELBs. The omission of MELB flooding analysis was not recognized until efforts involved with upgrading documentation associated with 10 CFR 50.49 (Environmental Qualification) discovered the oversight.

Accordingly, TVA contracted with Sargent and Lundy to perform a study of MELBs. Sargent and Lundy determined that flooding associated with MELBs could potentially submerge and impair components required for safe shutdown and threaten integrity of certain structures due to increased loading.

The identified concerns resulting from the MELB flooding study have been addressed by TVA. In order to comply with TVA internal design standards, certain actions (such as sealing building walls) were taken to minimize the impact of potential MELBs. Other actions (such as protecting cables from water) were to be implemented before restart of either unit.

Additional actions have been taken to improve communication across the engineering disciplines. In addition, probabilistic risk assessments (PRAs) typically yield estimates of reactor core damage from internal flooding events of 1E-05 to 1E-06 per year. Estimates of internal flooding having an impact on public risk are approximately 1E-08 or lower per year. The low probability for public health risk is because a flooding event must satisfy a fairly large set of conditions in order to be significant.

2.8 Reactor Scram Due to Air Leak From Incorrect Mounting Cap Screw in Air Test Pilot Valve

Oyster Creek; Docket 50-219; LER 87-029; General Electric BWR

On July 30, 1987, at about 4:45 a.m., operators were in the process of performing the daily main steam isolation valve (MSIV) five percent closure test. After completing the test on the inboard MSIV (NS03A), the operator proceeded to test the outboard MSIV (NS04A).

The operator depressed the test pushbutton and noticed that the red (open) indicating lamp promptly de-energized. Within about three seconds, a half scram signal due to MSIV closure (one of four MSIVs less than 90% open) was received. The operator immediately released the test pushbutton. However, the valve did not reopen fully, but remained in an intermediate position. The operator then gave the valve an open signal but no change was observed. At

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[*]MELBs are breaks in process piping whose operating temperature is below 200 °F 99% of plant operating time. Examples of such systems are the high pressure fire protection (HPFP) system, condenser circulating water (CCW), and component cooling system (CSS).

about the same time, a low control air pressure alarm was received. The instrument air pressure fell to about 75 psig. A second air compressor automatically started on low pressure and the operators quickly started a third air compressor.

The problem was diagnosed as an air leak which decreased the ability of MSIV NS04A to remain open. An attempt was made to reduce plant power to the point where one steam header is sufficient to maintain reactor pressure and steam flow. The operators rapidly reduced plant load using a combination of recirculation flow and control rods.

The Group Shift Supervisor (GSS) concluded that the valve was in an intermediate position because the difference in steam flow between the two headers remained constant. He then directed the operators to continue decreasing plant load. After about 15 minutes, the operators had decreased power to about 70%. Suddenly, the MSIV went fully closed. This caused a rapid pressure increase which resulted in a reactor scram. Peak reactor pressure, as indicated by the plant computer, reached about 1050 psig - the high pressure scram setpoint.

An inspection of the MSIV following the event revealed that a three-way air pilot valve had dislodged from the main valve block and developed an air leak. This caused the MSIV to close faster than normal during the slow closure test. When the operator released the test button, opening air pressure was reapplied, resulting in the valve remaining at an intermediate position. (MSIVs use air pressure to open; spring and air pressure to close). Later, the pilot valve fully dislodged, all supply air was lost, and the MSIV went fully closed.

Subsequent investigation revealed that there was insufficient thread engagement of the 1-inch mounting cap screws that secure the three-way pilot valve to the main valve block. The valve manufacturer was contacted and specified that the cap screw length should be 1-1/4 inches. The valve vendor approved the use of 1-1/2-inch cap screws. The root cause of this transient was attributed to insufficient thread engagement of the three-way air pilot valve mounting cap screws on MSIV NS04A.

The wrong length cap screws were used because the utility did not have a vendor manual which specified mounting cap screw length for these air valves. The plant drawings and procedures used for installation of these valves did not specify mounting cap screw length. In 1982 all the MSIV air valve mounting cap screws were replaced with 1-inch screws to standardize mounting cap screw length for these valves. It was the judgment of maintenance personnel at that time that 1-inch screws were best for this application.

All the air pilot valves on MSIVs were examined and found to have the same incorrect mounting cap screws. All MSIV air pilot valves were remounted with vendor approved cap screws. The MSIV closure and inservice test was performed on all MSIVs to assure proper operation of the newly mounted air pilot valves. The utility revised the MSIV air pilot valve maintenance procedure and specified the correct length mounting cap screws to avoid any misunderstanding in future maintenance. A vendor manual which specifies the proper cap screw length was ordered. Current work practices and procedures were reviewed to confirm that changes to installed equipment are not permitted without a proper engineering review.

2.9 Reactor Trip Due to Lightning Strike

Point Beach Unit 2; Docket 50-301; LER 87-002; Westinghouse PWR

On August 16, 1987, at 6:55 p.m., a lightning strike near Point Beach Nuclear Plant Unit 2 caused a reactor trip from 100% power. The reactor protection system (RPS) initiated a turbine trip. The turbine alarm sequence indicated a lockout on the 2X01 B and C phase transformers. The computer printout of the sequence of events showed a possible lightning strike prior to the trip sequence.

After the turbine trip, the automatic bus transfer for non-vital 4160 volt failed to take place. However, there was no loss of safeguards power supplies during this event. The emergency diesels were not required to start. Because non-vital power was interrupted, the reactor coolant pumps, turbine auxiliaries, circulating water pumps, steam generator main feed pumps, condensate pumps, and heater drain tank pumps tripped. As a result, main condenser vacuum was lost.

Rupture discs in the turbine blew out, indicating positive pressure in the main condenser after loss of vacuum. All primary system equipment functioned as designed. There was no actuation of safety injection. Pressure, level and temperature in the steam generators, reactor coolant system (RCS), and pressurizer remained within expected limits during the transient. Adequate natural circulation was indicated by differential temperatures between the hot and cold legs.

Data transmission from the 10-meter level on the primary meteorological tower was interrupted due to a lightning strike. The remaining levels on that tower and the other two towers on the system remained operational.

During the recovery of the plant, a decision was made to shut the main steam isolation valves (MSIVs) to isolate steam from turbine hall equipment. The A MSIV closed fully. The B MSIV closed to within one inch of its fully closed position. During a subsequent test, both valves closed normally. Past experience has shown that whenever there is a small amount of steam flow through these valves, they will fully close if initially closed as far as the B MSIV closed.

At about 7:15 p.m., the decision was made to declare an Unusual Event according to emergency plan procedures. Notification was initiated at about 7:30 p.m. At 8:05 p.m., after power had been restored and systems had stabilized, the Unusual Event was terminated.

The cause of this event appears to have been a lightning strike to a transmission line associated with 2X01 or to the ground near 2X01. The resulting voltage transient caused the B phase and possibly the C phase on

2X01 to arc to ground. This created a fault resulting in a generator breaker lockout. The lockout caused a turbine trip followed by a reactor trip.

When the arc occurred, a fault was created on the 4.16 KV non-vital buses (2A01 and 2A02). This fault prevented the synchrocheck relay from allowing a non-vital 4.16 KV automatic bus transfer to occur. The voltage on the non-vital buses (2A01 and 2A02) decayed rapidly after the breaker opened. It fell to less than 80% of the minimum required for operation of the synchrocheck relay; thus the automatic bus transfer did not function.

The health and safety of the utility employees involved and the general public were not affected during this event. The plant Final Safety Analysis Report discusses a loss of external electrical load as one of its analyzed accidents. In that analysis the assumed initial power level is 102% power and no credit is taken for the turbine trip of the reactor. The results of the analysis show that no fuel would be damaged. All systems responded as expected and no evidence of fuel damage was found.

2.10 Loss of Normal Power During Shutdown Due to Routing All Offsite Power Sources Through One Breaker

Vermont Yankee; Docket 50-271; LER 87-008; General Electric BWR

At about 2:00 p.m. on August 17,1987, the plant suffered a loss of normal power (LNP). At that time the facility was shut down for a refueling outage. The startup transformers and one of the two main output breakers had been taken out of service for testing. This action caused all sources of off-site power to be routed through one set of breakers.

At that time, a line fault, external to the plant, was transmitted down one of the lines supplying plant power. This fault, which also caused trips at other facilities in the area, caused the second main output breaker to open. The plant was now isolated from all sources of outside power.

When the second main breaker opened, a scram signal and all containment isolation signals were generated, as expected. All pumps stopped and the emergency diesel generators (EDGs) received a start signal. The EDGs started, and within 13 seconds of the LNP, power was available for automatic start of the following equipment:

a) the RHR pumps and the service water pumps (being used for shutdown cooling), and

b) the electric fire pump (which started due to low pressure in the service water and fire protection headers).

A temporary piping connection made from 2" schedule 80 polyvinyl chloride (PVC) piping connecting the service water system and the fire protection system burst shortly after the EDGs started. As a result of the break, about 2000 gallons of service water spilled onto the refueling floor of the reactor building. The water entered the floor drain system which contains several lengths of contaminated pipe, which in turn contaminated the service water. The flow rate exceeded the capacity of the floor drain system, causing the floor drain sump on the lowest level of the reactor building to overflow. Water also issued from several floor drains on two other floors of the building. Water pooled on the refueling floor and seeped through the gap between the reactor building refueling floor paneling and the reactor building exterior walls.

The cause of the pipe break was believed to be the result of near simultaneous starting of the service water pumps and the electric fire pump. The service water system was also partially drained at the time.

The temporary piping had been designed for normal system operating pressure. A review of the temporary piping for pressure surge was not required; therefore, no such review was performed. The temporary piping was designed for about 150 psig, but it was subjected to a larger than normal pressure surge when the pumps restarted after the emergency diesel generators started.

A test of the secondary containment was conducted as part of the cleanup and investigation after the event and the containment was found intact. An inspection of the various levels of the reactor building revealed no damage to equipment as a result of the spill.

Operators were able to isolate the pipe break in about ten minutes. Cleanup of the spill commenced about 30 minutes after the pipe break and was completed in about 14 hours.

If both emergency diesels had failed to start, power would still have been available to operate essential plant equipment through a tie line to Vernon Dam. This power source would have been available to the plant within two minutes.

2.11 Inoperability of Nuclear Service Water System Due to Incorrect Design Recommendation

Catawba Unit 1; Docket 50-413; LER 87-036; Westinghouse PWR

On October 12, 1987, Duke Power personnel determined that a violation of Technical Specifications (TS) occurred from 10:30 p.m. August 30, 1986, to 8:30 a.m. September 4, 1986. On August 22, 1986, Unit 1 was in cold shutdown in preparation for refueling. Unit 2 was at power. Diesel generator (D/G) 1A was removed from service for maintenance. While the D/G was out of service, nuclear service water (NSW) train A was entered as inoperable in the Technical Specification Action Item logbook for both unit 1 and unit 2. NSW flow was realigned per procedure to accommodate D/G 1A being out of service. However, in order to drain the reactor coolant loops in preparation for Unit 1 refueling, it was necessary to establish the operability of both trains of RHR on that unit. This required reestablishing NSW flow to the two component cooling heat exchangers, each of which cools one train of RHR.

To accomplish this, on August 29, Design Engineering provided instructions for throttling NSW flow to the component cooling heat exchanger on the NSW loop serving the inoperable D/G. This throttling established a configuration which allowed a single NSW pump to provide flow for postulated LOCA heat loads on Unit 2 while continuing to provide shutdown cooling on Unit 1.

However, the instructions were in error. They directed the crossover supply valve associated with the out-of-service D/G to be closed, rather than the crossover supply valve which isolates the degraded NSW loop from the non-essential header (as the previous procedure required). Therefore, only a single pump was available to supply flow to the non-essential header on the shutdown unit and to the essential headers. The NSW operating procedure was revised to incorporate the (erroneous) Design Engineering instructions.

The procedure was implemented and crossover valve 1RN48B was opened at about 10:30 p.m. on August 30. At this time, NSW train A became inoperable with respect to Unit 2, since NSW pump 2A would have been aligned to supply the Unit 1 non-essential header, which would have diminished flow to the 2A essential header. NSW train B was fully operable and capable of supplying post LOCA and shutdown cooling for both units during the period that NSW train A was unknowingly inoperable. The action statement associated with the TS applied to this situation, but it was not entered since station personnel were unaware of NSW train A inoperability.

On August 31, 1986, at 1:30 a.m., Unit 1 entered refueling mode. On September 1, at 8:20 a.m., Unit 2 went to hot standby due to a failure of the main turbine generator. However, on September 4, at 8:30 a.m., Unit 2 was (unknowingly) required to be in cold shutdown due to the inoperable NSW Loop A. On September 8, at 4:40 a.m., Unit 2 entered cold shutdown. This satisfied the applicable TS requirement, although about 92 hours had elapsed. This violated the TS requirement to achieve cold shutdown within the appropriate time interval. In cold shutdown, the TS requires one NSW Loop to be operable for the unit (NSW Loop B was operable).

The Licensee reported that heat load analysis and system testing have shown that the NSW system has adequate capacity to supply the LOCA demands of one unit and the shutdown cooling demands of the other unit. Therefore, the NSW system was being operated in a configuration believed to support the safety analysis for the station. Only one loop of NSW was available from August 30, 1986, to September 8, 1986, to supply post-LOCA flow requirements on one unit and shutdown cooling requirements on the other unit. The time period exceeded that allowed by Technical Specifications.

Revised heat load analysis and subsequent NSW flow balance has shown that a single NSW pump is sufficient to supply the post-LOCA loads on one unit and the shutdown loads on the other unit without isolating or throttling of NSW flows on the shutdown unit.

Operations personnel reviewed all NSW associated procedures to ensure appropriate actions were included in the event of an NSW malfunction. The emergency procedure for transferring to cold leg recirculation was revised to more clearly define the realignment of NSW.

Subsequent corrective action included:

1) Technical Specification changes were made which describe the shared aspects of the NSW system and provide corresponding actions to be taken when it is not fully operable.

2) Operations personnel reviewed all NSW associated procedures to ensure appropriate actions were included in the event of an NSW malfunction.

3) The operating procedure for the NSW system was revised to require an alternate cooling source when removing a D/G from service for an extended period.

4) The emergency procedures for the transfer to cold leg recirculation were revised to better ensure adequate NSW flow to necessary equipment.

5) NSW flow balance was performed to confirm the ability of one NSW pump to supply adequate NSW flow to both units.

3.0 ABSTRACTS/LISTINGS OF OTHER NRC OPERATING EXPERIENCE DOCUMENTS

3.1 Abnormal Occurrence Reports (NUREG-0090) Issued in July-Aug 1987

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. Copies and subscriptions of this document are available from the Superintendent of Documents, U.S. Government Printing Office, P.O. Box 37082, Washington, DC 20013-7982.

Date Issued	Report
7/87	REPORT TO CONGRESS ON ABNORMAL OCCURRENCES, OCTOBER-DECEMBER 1986, VOL. 9, NO. 4

There were nine abnormal occurrences during the period. Three occurred at NRC-licensed nuclear power plants, six occurred at other NRC licensees (industrial radiographers, medical institutions, industrial users, etc.), and none occurred at a Agreement State licensee.

The occurrences at the plants involved: (1) a loss of low pressure service water at Oconee, (2) degraded safety systems due to incorrect torque switch settings on Rotork motor Operators at Catawba and McGuire Nuclear Stations, and (3) a secondary system pipe break at Surry Unit 2 resulting in the death of four persons.

The other NRC licensee occurrences involved: (1) a release of Americium-241 at Wright-Patterson Air Force Base, (2) a therapeutic medical misadministration at the Cleveland Clinic Foundation, Cleveland, Ohio, (3) a suspension of License for Servicing teletherapy and radiography units of Advanced Medical Systems, Geneva, Ohio, (4) a therapeutic medical misadministration at St. Luke's Hospital, Racine, Wisconsin, (5) a therapeutic medical misadministration at Toledo Hospital, Toledo, Ohio, and (6) an immediately effective order modifying License and Order to Show Cause issued to an Industrial Radiography Company, Met-Chem Testing Laboratories of Utah, Inc., of Salt Lake City, Utah.

Also, the report updated information on: (1) the environmental qualification of safety-related electrical equipment inside containment (77-9), first reported in NUREG-0900-10 (October-December 1978); (2) the nuclear accident at Three Mile Island (79-3), first reported in Vol. 2, No. 1 (January-March, 1979); (3) differential pressure switch problem in safety systems at LaSalle, first reported in Vol. 9, No. 3 (July-September, 1986); (4) rupture of uranium hexafluoride cylinder and release of gases (86-3), first reported in Vol. 9, No. 1 (January-March, 1986); and (5) willful failure to report a diagnostic medical misadministration, first reported in Vol. 9, No. 2 (April-June, 1986).

In addition, items of interest that did not meet abnormal occurrence criteria but may be considered significant by the public involved: (1) emergency diesel generator problems at various nuclear power plants, (2) NRC Augmented Inspection Team sent to Hope Creek, (3) conviction of International Nutronics, Inc., and one employee in Federal District Court, and (4) NRC Augmented Inspection Team sent to Hatch facility.

3.2 Bulletins and Information Notices Issued in July-August 1987

NRC Bulletins are used primarily to communicate with the industry on matters of generic importance or serious safety significance (i.e., if an event at one reactor raises the possibility of a serious generic problem, an NRC bulletin may be issued requesting licensees to take specific actions, and requiring them to submit a written report describing actions taken and other information NRC should have to assess the need for further actions). A prompt response by affected licensees is required and failure to respond appropriately may result in an enforcement action. When appropriate, prior to issuing a bulletin, the NRC may seek comments on the matter from the industry (Nuclear Management and Resources Council, 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. The following Bulletin was issued during July-August 1987:

Bulletin	Date Issued	Title
87-01	7/9/87	THINNING OF PIPE WALLS IN NUCLEAR POWER PLANTS (Issued to all power reactor facilities holding an operating license or construction permit)

Information Notices are rapid transmittals of information which may not have been completely analyzed by the 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. The following Information Notices were issued during July-August 1987:

Information Notice	Date Issued	Title
87-30	7/2/87	CRACKING OF SURGE RING BRACKETS IN LARGE GENERAL ELECTRIC COMPANY ELECTRIC MOTORS. (Issued to all power reactor facilities holding an operating license or construction permit)
87-31	7/10/87	BLOCKING, BRACING, AND SECURING OF RADIOACTIVE MATERIALS PACKAGES IN TRANSPORTATION (Issued to all NRC licensees)
87-32	7/10/87	DEFICIENCIES IN THE TESTING OF NUCLEAR-GRADE ACTIVATED CHARCOAL. (Issued to all power reactor facilities holding an operating license or construction permit)

Information Notice	Date Issued	Title
87-33	7/24/87	APPLICABILITY OF 10 CFR PART 21 TO NONLICENSEES (Issued to all NRC licensees)
87-34	7/24/87	SINGLE FAILURES IN AUXILIARY FEEDWATER SYSTEMS (Issued to all holders of an operating license or a construction permit for pressurized water reactor facilities)
87-35	7/30/87	REACTOR TRIP BREAKER, WESTINGHOUSE MODEL DS-416, FAILED TO OPEN ON MANUAL INITIATION FROM THE CONTROL ROOM (Issued to all nuclear power facilities holding an operating license or a construction permit employing W DS-416 reactor trip breakers)
87-36	8/4/87	SIGNIFICANT UNEXPECTED EROSION OF FEEDWATER LINES (Issued to all power reactor facilities holding an operating license or construction permit)
87-37	8/10/87	COMPLIANCE WITH THE GENERAL LICENSE PROVISIONS OF 10 CFR PART 31. (Issued to all persons specifically licensed to manufacture or to initially transfer devices containing radioactive material to general licensees, as defined in 10 CFR Part 31)
87-38	8/17/87	INADEQUATE OR INADVERTENT BLOCKING OF VALVE MOVEMENT (Issued to all power reactor facilities holding an operating license or construction permit)
87-39	8/21/87	CONTROL OF HOT PARTICLE CONTAMINATION AT NUCLEAR POWER PLANTS (Issued to all power reactor facilities and spent fuel facilities holding an NRC license or construction permit)
87-40	8/31/87	BACKSEATING VALVES ROUTINELY TO PREVENT PACKING LEAKAGE (Issued to all power reactor facilities holding an operating license or construction permit)
87-41	8/31/87	FAILURES OF CERTAIN BROWN BOVERI ELECTRIC CIRCUIT BREAKERS (Issued to all power reactor facilities holding an operating license or construction permit)

3.3 Case Studies and Engineering Evaluations Issued in May-June 1987

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 safety interest for further review as either an engineering evaluation or a case study. An engineering evaluation is usually an immediate, general assessment to determine 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 staff weeks of investigation time.

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

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

Engineering Evaluation	Date Issued	Subject
AEOD/E708	8/87	DEPRESSURIZATION OF REACTOR COOLANT SYSTEMS IN PWRS An inadvertent reactor trip at Salem Unit 2 on August 26, 1986, resulted in a loss of normal pressurizer spray, loss of auxiliary spray, and loss of one of the power operated relief valves (PORVs). Repeated PORV actuations were caused by continued operation of high pressure safety injection. Quick operator action restored the plant to a stable condition. Extrapolation of this sequence of events to a steam generator tube rupture accident or a forced natural circulation cooldown highlights areas of safety analyses, plant operation, and emergency procedures that could be improved.

Engineering Evaluation	Date Issued	Subject
AEOD/E708 (cont'd)		The likelihood of severe core damage from steam generator tube rupture accidents was previously estimated to be small. Still actions to facilitate the operator's recovery from this event may be prudent because of the potential for bypassing containment during this accident. The principal conclusions and findings from the study are:

(1) There are several systems available for primary system pressure control. All plants have a normal pressurizer spray system and an auxiliary spray system. Most plants have PORVs that can be used to depressurize the primary system.

(2) Generally, none of the systems identified in Item (1) above are controlled by limiting conditions for operation in the technical specifications. Experience has shown that one or portions of all these equipment/systems can be out of service for extended times while the plant is operating.

(3) Operating procedures for utilizing the above mentioned equipment/systems are not consistent at Westinghouse plants. For all events, the procedure guidelines use the auxiliary spray as a backup to the normal spray, except for steam generator tube rupture accidents which use the PORVs as a backup o the normal spray. PORVs have a tendency to stick open and cause a small loss of coolant accident which complicates recovery from a tube rupture.

(4) Of primary concern from a pressure control standpoint, is a steam generator tube rupture accident because of the potential for bypassing the containment.

(5) In the past, systems evaluation criteria for mitigating a steam generator tube rupture accident are not as stringent as those used for reviewing other design basis accidents. However, a recent staff evaluation of a Westinghouse Owners Group topical report on SGTR indicates that single failure and equipment operability will be considered in future evaluations.

Engineering Evaluation	Date Issued	Subject
AEOD/E708 (Cont'd)		(6) The upper head temperature may adversely influence plant response characteristics in a tube rupture accident. Many plants operate with upper head temperatures close to core exit temperatures that correspond to saturation pressures above the setpoint on the steam generator safety valves. The upper head would act as a pressurizer and maintain primary system pressures above the pressure in the faulted steam generator and potentially challenge the steam generator safety valves.
		(7) The likelihood of severe core damage and offsite doses from steam generator tube rupture accidents is proportional to human error probabilities associated with recovery from the accident. Continuous operator attention is required to stabilize the plant after a tube rupture, in contrast to automatic system actuations and simple on/off manual actions used for mitigating other design basis accidents
		(8) Several hours may be available to preclude a steam generator tube rupture accident from evolving into a severe core damage event due to depletion of the refueling water storage tank. However, loss of pressure control early in the event may result in prolonged discharge of coolant into the faulted steam generator and subsequent failures in the secondary system (or the pressurizer PORV) that exacerbate the situation and significantly complicate the operator's ability to recover.

Engineering Evaluation	Date Issued	Subject
AEOD/E708 (Cont'd)		(9) The circumstances of the Salem event, as they relate to a potential tube rupture event, are not unique. Multiple pieces of equipment out of service are within allowable practice. Multiple coincidental failures have been observed during other operational events. The Salem event raises an issue: Do circumstances that prevailed during the event facilitate appropriate operator action or detract from it? On one hand, there appears to be ample time and acceptable emergency procedures for the operator to successfully respond to a steam generator tube rupture accident. On the other, control of the design, operability, and availability of the mitigating systems appears lacking. The evidence clearly indicates that primary pressure control capability could be enhanced.
AEOD/E709	8/24/87	AUXILIARY FEEDWATER PUMP TRIPS CAUSED BY LOW SUCTION PRESSURE On January 27 and 29, 1987, Millstone 3 experienced an event in which each of the unit's two motor-driven auxiliary feedwater (MDAFW) pumps A and B tripped immediately after being started during quarterly surveillance testings. Pump A tripped three times which pump B tripped once. All trips occurred several seconds after pump starts. The trips were determined to be caused by suction pressure oscillations that resulted in spurious low suction pressure trip signals. This spurious low pressure trip is a common mode failure for the two MDAFW pumps. Three additional events found in this review had similar spurious low-suction pressure trips that resulted in a partial loss of the AFW system.

Engineering Evaluation	Date Issued	Subject
AEOD/E709 (Cont'd)		The additional events occurred at Trojan, D.C. Cook 1 Zion 2. The low pressure condition causing the AFW pump trips in these three events were also generated by pressure oscillation or fluctuation in the suction lines during pump startup transient or in the middle of operation. The pump fluctuation at Trojan and Zion 2 was the result of excessive suction flow, while that at D.C. Cook 1 was induced by turbine speed oscillations due to a faulty governor.

Low suction pressure trips are generally provided for protection of the pumps against loss of suction head and cavitation. The events show that low suction pressure trips constitute a common mode failure that can potentially render the AFW system inoperable and the plant would lose its redundancy in core heat removal capability. Although the trips may be removable in a relatively short period and the pump can be manually restarted, the potential exists that system response time may increase beyond the time limit required by the technical specifications, and the reliability and capability of the AFW system would be compromised. Without some sort of low suction pressure trip, either automatic or manual, pump protection may not be adequate. The findings and conclusions from this study are:

(1) Low-suction pressure trips have occurred to the AFW pumps of different system configurations at four plants, even though sufficient suction head was available. The spurious low pressure trips were attributed to pressure oscillations or fluctuations in the suction lines, which created a momentary pressure drop. The momentary low pressure was sensed and actuated the pressure trips of the pumps.

(2) The pressure oscillation or fluctuation was a result of hydraulic hammering, excessive suction flow or turbine speed oscillation.

Engineering Evaluation	Date Issued	Subject
AEOD/E709 (Cont'd)		(3) The flow path and pump alignment combinations, which appeared to contribute to the occurrence of pressure oscillation upon pump operation, were not the normal operational configuration for the system and had not been fully specified or considered in the operational conditions for the design of the pump low pressure protection system.
		(4) Although the pressure oscillation or fluctuation dampened very rapidly, they were initially quite severe and were of sufficient magnitude that the pump suction pressure dropped below the trip setpoints for a brief period and actuated the low pressure trips.
		(5) The low pressure condition only existed momentarily. To prevent spurious low pressure pump trips from occurring, the licensee of Zion has installed a time delay relay in the control circuitry of the MDAFW pumps. The relay momentarily bypasses the low suction pressure trip during pump start. The existing time relays for the AFW pumps at Trojan were also adjusted to provide sufficient time for suction flow to stabilize before actuation of the low pressure trips, without degrading the pump protection from cavitation.
		(6) The corrective actions taken by the other two plants where the trip problem occurred are different. The licensee of Millstone 3 removed xthe low suction pressure trip from both MDAFW pumps since it was not part of safety analysis and was an operational feature provided for equipment protection. The low suction pressure trip was replaced with an alarm/operator action combination at D.C. Cook 1. The alarm will actuate when the water level in the CST drops to the point where there is still 14 minutes to reach the center line of the suction pipe for the AFW pumps. The time is sufficient for the operator to take appropriate actions.

Engineering Evaluation	Date Issued	Subject
AEOD/E709 (Cont'd)		(7) Low suction pressure trip function is provided to protect centrifugal pumps from cavitation and subsequent damage. It trips the pump within a desirable time upon a loss of adequate pressure to provide the necessary net positive suction head (NPSH) at the suction of the pump. Without low pressure trip or using alarm/operator action combination, as in the cases of Millstone 3 and D.C. Cook 1, the automatic pump protection may not be adequate. There are conditions other than inadequate available suction head that can cause cavitation and damage the pump, such as air or vapor binding of the suction line, or inadvertent closure of the suction valve. An alarm/operator action combination based on available suction head, such as water level in CST, by itself would not provide protection against vapor binding or suction valve closure.

3.4 Generic Letters issued in July-August 1987

Generic letters are issued by the Office of Nuclear Reactor Regulation, Division of Licensing. They are similar to NRC Bulletins (see Sect. 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.

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

Generic Letter	Date Issued	Title
87-12	7/9/87	50.54(f) LETTER REGARDING LOSS OF RESIDUAL HEAT REMOVAL (RHR) DURING MID-LOOP OPERATION (Issued to all holders of an operating license or a construction permit for pressurized water reactor facilities)
87-13	7/10/87	INTEGRITY OF REQUALIFICATION EXAMINATIONS AT NON-POWER REACTORS (Issued to all non-power reactor licensees)
87-14	8/4/87	REQUEST FOR OPERATOR LICENSE SCHEDULES (Issued to all power reactor licensees)

3.5 NRC Documentation Compilations

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

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 users of radioactive materials, and (2) non-docketed material received and generated by NRC pertinent to its role as a regulatory agency. This series of documents is indexed by Personal Author, Corporate Source, and Report Number.

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

Copies and subscriptions of these three documents are available from the Superintendent of Documents, U.S. Government Printing Office, P.O. Box 37082, Washington, DC 20013-7982.

* U.S. GOVERNMENT PRINTING OFFICE:1988-202-292:80167

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