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POWER REACTOR EVENTS

United States Nuclear Regulatory Commission

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Power Reactor Events is a bi-monthly newsletter that compiles operating experience information about commercial nuclear power plants. This includes summaries of noteworthy events and listings and/or abstracts of USNRC and other documents that discuss safety-related or possible generic issues. It is intended to feed back some of the lessons learned from operational experience to the various plant personnel, i.e., managers, licensed reactor operators, training coordinators, and support personnel. Referenced documents are available from the USNRC Public Document Room at 1717 H Street, Washington, D.C. 20555 for a copying fee. Subscriptions of Power Reactor Events may be requested from the Superintendent of Documents, U.S. Government Printing Office, Washington, D.C. 20402, or on (202) 783-3238.

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Period Covered: September-October 1986

1.0 SUMMARIES OF EVENTS

1.1 <u>Speed Setting Motor Problems in Auxiliary Feedwater Pump Turbine Governor at Davis-Besse</u>

On September 26, 1986 at Davis-Besse,* the auxiliary feedwater pump turbine (AFPT) 1-2 governor speed setting motor was found to be drawing abnormally high current. Arcing with accompanying current spikes and wisps of smoke were observed. Engineering and vendor evaluation determined that this may have indicated motor failure, and the speed setting motor was therefore considered inoperable. Loss of the speed setting motor prevents automatic or manual control from the control room of the AFPT speed, which is used to control feed flow to the steam generators. Following investigation of the inoperability, the vendor initially postulated that since the motor is a non-sealed design located in an oil mist environment, oil was entering the motor, producing motor degradation. The licensee has determined that this mechanism may possibly lead to failure of the motor. Testing conducted by the licensee also determined that oil may enter the motor during the governor oil fill process, since the motor is located in close proximity to the governor oil fill port. Since the AFPT 1-1 governor is identical, both auxiliary feedwater trains were affected. The event is detailed below.

On September 26, 1986, the licensee's Engineering Department determined that the auxiliary feedwater system (AFW) turbine governor, MK0031/32, speed setting motors should be considered inoperable. This was based on information supplied by the governor vendor. The AFPT governor is a Woodward Governor Company model PGG with speed setting motor part No. 36627-23, supplied by the Terry Corporation for use on the AFPTs. The plant was in cold shutdown with the AFW system not required and in a shutdown lineup. The motor problem was discovered during inspection of the AFPT 1-2 governor by a Woodward service representative and licensee Engineering staff. When the governor upper housing cover was removed and the speed setting motor was operated, light wisps of smoke were observed emitting from the vent holes in the motor casing. Current measurements taken showed amperage of 150 ma to 250 ma with intermittent higher spikes. Measurements taken on the spare governor for comparison were 70-80 ma with no spiking.

The AFPT 1-2 speed setting motor was removed and the no load current was measured at 150 ma. Arcing and associated current spikes were again observed. Woodward stated that 114 ma at no load is the maximum acceptable current and that continued operation of the motor should not be relied upon. The AFPT 1-1 governor is identical in design. Failure of the speed setting motor would result in loss of the ability to adjust AFPT speed in the automatic or manual modes from the control room. This results in the loss of the ability to control feedwater flow to the steam generator from the control room. Only local manual control of the AFPT would be available.

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*Davis-Besse is an 860 MWe (net) MDC Babcock & Wilcox PWR located 21 miles east of Toledo, Ohio, and is operated by Toledo Edison Company.

The root cause of the inoperability (degradation) was investigated. The speed setting motor is not a sealed design and is located in an oil mist environment. The Woodward Governor Company initially postulated that oil and/or contaminants may have been entering the motor through vent holes in the motor, causing premature degradation. The licensee determined that this mechanism may possibly lead to failure of the motor. Testing conducted by the licensee determined that when oil is added to the governor, the motor casings could be covered with oil. Since the casing is a non-sealed design, oil may enter through the seams between the motor case components. This oil is deposited on the commutator and serves as a bonding agent for normally generated commutator/brush wear particles. These particles could then form a bridge between the commutator segments, causing a short circuit in the motor. The short circuit leads to significant increase in the motor current draw. Testing demonstrated that after 5.5 hours with approximately 2 ml of entrapped oil, the current draw reached a nominal 800 ma, with peaks up to 2000 ma. Smoke was observed emanating from the motor and the operating test was terminated at 5 hours, 50 minutes.

The defect at Davis-Besse had no immediate safety consequence at the time of discovery, because the plant was in cold shutdown and the AFW system was not required to operate. Had the defect gone undetected, the increased current drawn by the shorted motor could have resulted in the power supply overcurrent protection device shutting the motor down. This failure of the speed setting motor during a higher plant mode could have resulted in a loss of AFW flow control. If this occurs in both trains, it could result in the creation of a substantial safety hazard during the hot standby, startup, or power operation modes. Operator action would be required to either minimize an overcooling transient or initiate feedwater flow to the steam generator for decay heat removal. At Davis-Besse, local manual control of the AFPT governor would be available, as would a newly installed motor driven feedwater pump to supply auxiliary feedwater to mitigate the consequences of the speed setting motor failure.

The Woodward Governor Company supplies speed change motors which are modified (sealed) to resist oil penetration and vibration. As a corrective action, these modified motors were qualified for use and installed in the AFPT governors. A review of all other governors at Davis-Besse was performed; it was found that no others have open speed setting motors in an oil mist/spray environment that could lead to failure.

The Terry Corporation was informed of the speed setting motor failure. Northeast Utilities also was informed of the problem on September 27, 1986, when the Terry Corporation notified the Davis-Besse licensee that Millstone Unit 3* has a PGG governor in that facility. (Ref. 1.)

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*Millstone Unit 3 is a 1149 MWe (net) MDC Westinghouse PWR located 3 miles southwest of New London, Connecticut, and is operated by Northeast Nuclear Energy.

1.2 Simultaneous Inoperability of One Diesel Generator and Another Diesel's Cooling Pump Due To Component Failures During Testing at Prairie Island Units 1 and 2

On September 7, 1986, with Prairie Island Unit 1 at 100% power and Unit 2* at 88% power, diesel generator (DG) D1 failed to start during an operability test after cranking for 10 seconds. The DG was declared inoperable. A few hours later, while running the No. 22 diesel cooling water pump (DCLP) to prove operability per technical specifications, a small oil line burst; the pump was shut down and declared inoperable. With these two components inoperable, a power decrease was begun on both units as required by technical specifications. Repair of the oil leak on the No. 22 DCLP was completed, and the pump was restarted and proven operable. The power decrease was halted and both units were returned to normal operation. The cause of the DCLP inoperability was the rupture of brass tubing, which was replaced with stainless steel. The cause of the inoperability of DG D1 was not immediately apparent, but further investigation and testing revealed that leakage through the fuel header pressure return orifice check valve allowed the fuel oil header to drain during idle periods. The events are detailed below.

On September 7, 1986, both units were at steady-state power, with Unit 1 at 100% and Unit 2 at 88% power. An operability test of DG D1 was to be done in preparation for taking the No. 22 DCLP out of service for preventive maintenance. At 11:55 p.m., DG D1 failed to start after cranking for 10 seconds, and the start failure annunciator and 86 Lockout were received. The DG was declared inoperable.

With DG D1 inoperable, testing in accordance with Technical Specification 3.7.B.2.(a) was begun. At 12:28 a.m. on September 8, DG D2 was started to prove operability. After DG D2 was proven operable, the No. 22 DCLP was started to prove operability. At 5:30 a.m., after running a short time, tubing to the lube oil low pressure alarm switch ruptured. Operators at the scene took local control and shut down the pump. At 3:34 a.m., with DG D1 inoperable and the No. 22 DCLP inoperable, a power decrease was begun on both units. Rather than test any more equipment, manpower was allocated to repair the oil leak on the No. 22 DCLP. Repair of the oil leak was completed and, at 4:06 a.m., the pump was restarted and proven operable. The power decrease was halted and both units were shortly returned to normal operation.

The cause of the inoperability of the No. 22 DCLP was the rupture of brass tubing on which a pressure switch was mounted in a cantilever fashion. Engine vibration caused work-hardening of the brass tubing and eventual brittle fracture.

The cause of the inoperability of DG D1 was not immediately apparent. Further investigation and testing was done as follows:

- At 1:38 a.m. on September 8, the 86 Lockout was reset so that it could be determined if the governor shutdown solenoid plunger was stuck in the shutdown position. The plunger was found to be in the proper position.

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*Prairie Island Unit 1 is a 503 and Unit 2 is a 500 MWe (net) MDC Westinghouse PWR located 28 miles southeast of Minneapolis, Minnesota. They are operated by Northern States Power.

At 1:50 a.m., DG D1 was started from the control room. During this start, it was noted that the DG took an abnormally long time to start. It was suspected at this time that the failure of DG D1 to start was due to a fuel system problem. At 7:26 a.m., DG D1 was again started; this time no problems were observed.

- At about 8:10 a.m., work was begun to investigate potential problems with the fuel system. Leakage tests were performed on the fuel oil pump discharge check valve and the fuel oil pump suction piping back to the foot valve in the day tank. These tests revealed no problems. The packing of the fuel oil hand priming pump was replaced. The fuel oil pump discharge relief valve was removed and tested. The investigative work uncovered no problems which could have caused the failure of DG D1 to start.

- On the morning of September 9, DG D1 was successfully started three times from the DG room, while in local control. Prior to the second of these starts, the air supply to the governor oil booster was disconnected and capped to determine if this would adversely affect the ability of the diesel to start. It was found that without the oil boost, the governor was slower to respond, but the diesel still started within 10 seconds. At 12:03 p.m., DG D1 was started per its normal surveillance procedure to prove operability. At 3:01 p.m., the DG was declared operable.

- A schedule was developed for increased testing and further investigation of DG D1 to assure its reliability, since the cause of its failure to start had not been determined. It was started successfully on September 9 through 12, September 15, and September 18. A special test was developed to determine if the fuel oil header was draining down excessively between starts. The fuel header pressure was monitored immediately following the operation of the fuel oil hand priming pump. This revealed that the pressure decay rate was dependent on the amount of time the DG was idle.

- On the morning of September 19, DG D1 was removed from service and the fuel header pressure return orifice check valve was removed for inspection. The testing and inspection of the check valve revealed seat leakage which was caused by a nick in the rubber O-ring seat. The valve was replaced and, by 12:24 p.m., DG D1 was started and declared operable.

The apparent cause of the D1 inoperability was leakage through the fuel header pressure return orifice check valve, which allowed the fuel oil header to drain during idle periods. The purpose of this spring check valve is to allow excess fuel oil to return to the day tank while the engine is operating, and to prevent the fuel header from draining down while the engine is idle. Air is allowed to enter the fuel header from the clean fuel return line vents through the bodies of the injection pumps. This source of air, along with the leaky check valve, caused the fuel header to drain down.

Time between diesel starts also was a factor. The typical interval between starts is 2 to 3 weeks; on this occasion the interval was 25 days. This apparently allowed draining to continue to the point that it affected diesel operation.

The leaking check valve was a spring check valve supplied with the Model 38TD8-1/8 DG made by Fairbanks-Morse. Corrective action included replacing the valve. A similar check valve installed on DG D2 will be inspected at the next scheduled preventive maintenance outage. In the interim, the hand priming pump is being operated daily to assure that the fuel oil header remains filled.

A temporary repair to the ruptured oil line on the No. 22 DCLP was made quickly. The oil line was permanently repaired by replacing the brass tubing with stainless steel tubing. This repair will also be done on the No. 12 DCLP. (Ref. 2.)

Events related to the oil line rupture were studied in an NRC engineering evaluation (AEOD/E612) on "Emergency Diesel Generator Component Failures Due to Vibration," issued in December 1986. The evaluation concerned cracking of small bore piping that resulted in inoperability of DGs. The cracked lines were found in DG lube oil, fuel oil, and cooling water systems. The piping cracks, which were caused by cyclic fatigue that resulted from engine-induced vibration, were not detected by the inservice inspection or the preoperational testing program for the piping. The failures were only discovered after the cracks propagated completely through the tube wall, and fluid was observed leaking from the pipes. In the events reviewed, the associated DG became inoperable and the plant lost its required onsite emergency ac power redundancy. In one event, a fire occurred as lube oil spraying from a cracked lube line was ignited by the hot exhaust piping of the diesel engine.

The evaluation indicated that fatigue failures induced by steady-state operation, such as plant equipment or engine-induced vibration, are not normally analyzed in the original piping design. A more complete design review is typically done only after related problems are identified during plant operation. Often the problem is not detected until a leak occurs. Such leaks could result in sudden disabling of the DGs when needed, and could adversely affect a safe plant shutdown in the event of a loss of offsite power.

1.3 Minor Radioactive Release into Control Room Due to Control Room Relief Damper Installation Deficiency at Zion Units 1 and 2

At Zion Unit 1* on September 11, 1986, while Operating Department personnel were lowering the level in the spent resin storage tank (SRST), a vent path was established into the auxiliary building from the waste gas system. Unit 1 was in cold shutdown and Unit 2 was operating at 99% power at the time. Investigation showed incorrect SRST level indication leading to establishment of the vent path. Radiation Chemistry Technicians reported elevated background radiation readings in various rooms fed by the computer and miscellaneous rooms' heating, ventilating, and air conditioning (HVAC) system (OV), and in the control room, which is fed by the control room HVAC system (PV). At the same time, the auxiliary building stack and the Unit 2 purge room radiation monitors showed increased readings. Subsequently, Technical Staff Engineers reported that 4500 cubic feet of waste gas had been lost, and

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*Zion Units 1 and 2 are each 1040 MWe (net) MDC Westinghouse PWRs located 40 miles north of Chicago, Illinois, and are operated by Commonwealth Edison Company.

the flow path was identified as most likely via the SRST drain. The flow path allowed waste gas to be directed to auxiliary building areas below the OV and PV HVAC system relief dampers. Due to design/installation deficiencies, the systems pulled air from the auxiliary building into the OV and PV systems through the closed relief dampers. Subsequent to identifying this flow path, the PV relief dampers were failed closed and blanked off with sheet metal, and the OV airtight relief isolation damper was failed closed to eliminate the flow paths. A study is being conducted by the licensee and the architect engineer to develop long term corrective actions to these problems. The event is detailed below.

On September 11, 1986 while Operating Department personnel were lowering the level in the SRST, a vent path from the waste gas system was established, allowing waste gas into the auxiliary building. Radiation Chemistry Technicians reported elevated background radiation readings as high as 2200 cpm in the radiation chemistry offices, technical support center, labs, and various rooms, all fed by the OV and PV HVAC systems. At the same time, the auxiliary building stack and Unit 2 purge room radiation monitors showed increased readings.

Based on the elevated radiation monitor readings, SRST draining was terminated. Subsequently, Technical Staff Engineers reported that 4500 cubic feet of waste gas had been lost, with the flow path identified as most likely via the SRST drain. The flow path allowed waste gas to be discharged to auxiliary building areas below the OV and PV HVAC system relief dampers. These relief dampers do not seal airtight. Due to design/installation deficiencies, the sytems pulled air from the auxiliary building into the OV and PV systems through the systems' closed relief dampers, thus introducing waste gas into the systems.

Once this flowpath into the OV and PV systems was identified and verified by helium injection, the OV relief isolation damper (an airtight type damper downstream of the normal OV relief damper) was failed closed. The PV relief dampers were also failed closed and blanked off with sheet metal. Further helium injection tests verified that the original flowpath into PV and OV systems no longer existed.

Investigation into the cause of the event revealed that the SRST level indication system improperly showed level when the tank actually was completely drained, creating the vent path to the auxiliary building. The gas release into the PV and OV systems was caused by: (1) the design/installation deficiencies relating to the PV relief dampers, and (2) the OV system not being in its accident mode (i.e., its relief isolation damper was not closed). The OV system problem was due to a partially completed modification not being left in a state that would fulfill the design intent of the modification.

In 1980, a modification was written to install a makeup air unit and various airtight isolation dampers in the OV system to allow isolation of nonessential areas of the OV system if the OV system went into the accident mode. The areas remaining open to the OV system while in the accident mode would be the technical support center and the auxiliary electric rooms. By late 1982, the isolation dampers were installed but, through inadequate administrative control over partially completed modifications, the OV relief isolation damper was not failed closed. This potential path was not identified and the damper remained open, in its non-accident position, pending final completion of the modification.

The PV system relief damper problems are a matter of a system not being installed as designed. The original design called for one relief damper located in ductwork coming from the common discharge ductwork of the PV system return fans. However, the installation is such that each return fan has its own relief damper in its own separate discharge ductwork. Since, by design, only one PV return fan runs at a time (each is 100% capacity), the non-running return fan relief damper is under a suction pressure (greater than auxiliary building negative pressure) through the common suction ductwork of the return fans. Hence, even though the PV system was in the accident mode (isolated from outside air), a leakage path still existed from the auxiliary building into the PV system. Note that when the OV isolation damper modification is complete, the OV system will go into its accident mode any time the PV system goes into its accident mode.

A study is being conducted by the licensee and the architect engineer (Sargent & Lundy) to develop long term corrective actions to these problems. The study includes PV and OV system configuration verification, air flow modeling of the systems, release inleakage rates determination, and review of where more airtight isolation dampers are required. Relating to the original release, the operating procedures for draining the SRST are being changed, and the SRST level control indication system was recalibrated. Also, the response of radiation monitors relative to this event or more serious gas releases are being reviewed. Abnormal Operating Procedure AOP-5, "Radiation Monitor-High Activity Alarm," is being reviewed for possible clarification of responses to control room and technical support center high radiation events.

Since 1982, when the OV system modification work was done, the review process for incomplete modifications has been revised extensively. Status of incomplete modifications is better documented and is reviewed by more supervisory personnel than was the case in 1982. These improvements in the review system should prevent recurrence.

This event was reportable under 10 CFR 50.73(a)(2)(v), as a condition which could have prevented the fulfillment of the safety function of systems needed for the safe shutdown of the plant. However, due to the low activity reported during the radiation chemistry surveys that were conducted (maximum count rates reported were 2200 cpm), the safety significance of this gas release was minimal, and plant technical specification release rate limits were not exceeded. Since inleakage flow rates into the PV and OV systems are not known and are difficult to determine, the consequences of a major release in the auxiliary building are unknown. (Ref. 3.)

1.4 Broken Pipe Restraint Reveals Error in Piping Analysis at Crystal River Unit 3 - Update

This event was first reported in Power Reactor Events, Vol. 7, No. 5, pp. 10-12, issued in May 1986. It is updated based on information provided in a revised Licensee Event Report (Ref. 4).

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*Crystal River Unit 3 is an 821 MWe (net) MDC Babcock & Wilcox PWR located 7 miles northwest of Crystal River, Florida, and is operated by Florida Power Corporation.

On October 28, 1985, Crystal River Unit 3* was operating at 96% reactor power when a cracked concrete support pedestal for the seawater discharge piping from the A and B nuclear services closed cycle cooling water system heat exchangers (SWHE 1A and SWHE 1B) was discovered. Investigation into the cause of the crack revealed an error in the computer piping analysis; expansion joints in the nuclear services seawater system piping had been modeled incorrectly. While the piping reanalyses were being performed, an additional problem was discovered. A rigid seismic restraint used in the computer model for the nuclear services seawater system was not included in construction documentation and, therefore, was never installed. Piping analyses were rerun and preliminary results indicated that the damaged pedestal could not withstand the revised design loads (pressure, dead weight and seismic.) Further refinement of the piping analysis showed that the original (undamaged) pedestals were also not capable of withstanding the revised loads.

Repairs were made to reinforce all of the piping support pedestals for the nuclear services closed cycle cooling water heat exchangers. Tie rods were installed across the nuclear services seawater system piping expansion joints to eliminate the pressure on the pedestals, and a seismic restraint was fabricated and installed in the location that had been omitted in the original design.

An investigation has been completed by the architect/engineer (Gilbert Associates) to determine generic implications of the omission of the pipe support, and the necessity for tie rods on safety-related rubber expansion joints. The evaluation determined that this event does not present a generic concern. This determination was made after review of approximately 45 work packages in which the analyst who made the mistake at Crystal River Unit 3 had over 400 opportunities to make the same mistake again and did not. The evaluation also determined the integrity of the nuclear services seawater system supply and discharge piping to nuclear services closed cycle cooling water heat exchangers is not assured without the addition of tie rods to the rubber expansion joints. Those tie rods have been added.

Six expansion joints in systems other than the nuclear services seawater system have been identified as requiring tie rods. All of these joints are in the control complex chilled water system. A modification was prepared and tie rods were installed on these six joints. This modification was necessary to bring the piping into compliance with existing stress analyses and applicable code requirements. However, evaluation results show the system would have maintained structural integrity and performed its intended function during normal operation and a safe shutdown earthquake seismic event.

1.5 Inadvertent Engineered Safety Features Actuation and Subsequent Reactor Trip at Palo Verde Unit 1 - Update

This event was first reported in Power Reactor Events, Vol. 7, No. 6, pp. 4-8, issued June 1986. It is updated based on information provided in a revised Licensee Event Report (Ref.5).

On December 16, 1985, at about 6:12 p.m., a ventilation fan in the Palo Verde Unit 1* A train of the balance of plant engineered safety features actuation

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*Palo Verde Unit 1 is a 1270 MWe (net) MDC Combustion Engineering PWR located 36 miles west of Phoenix, Arizona, and is operated by Arizona Public Service. The unit was in startup testing at the time of the event.

system (BOP ESFAS) auxiliary relay cabinet tripped off and caused the cabinet to overheat. This resulted in the BOP ESFAS logic cards malfunctioning, and activated the A train of the BOP ESFAS systems. This included the loss-of-power sequencer which tripped open the normal feeder breaker to the Class 1E 4160 V bus, deenergizing the bus and shedding its electrical loads. The A diesel generator started; however, the output breaker did not close and reenergize the bus. Manual attempts to reenergize the loads on the bus were unsuccessful until the loss-of-power load shed signal was removed by pulling fuses in the BOP ESFAS cabinet. During this event, the B essential chiller tripped on low refrigerant temperature. With the A diesel generator and the B essential chiller declared inoperable, a reactor shutdown was begun from about 50% power in accordance with technical specifications.

At about 11:30 p.m., with reactor power at about 2%, the Control Room Operator was unable to maintain feedwater flow to both steam generators with the running main feedwater pump. The main feed pump was manually tripped, and the non-essential auxiliary feedwater (AFW) pump was started. Malfunctioning control room indications on motor amperage and pump flow caused the operator to trip the nonessential AFW pump and start the essential B AFW pump. Steam generator wide range level was approximately 50% when the B AFW pump was started; when the steam generators were fed with cold feedwater it apparently caused the water level to shrink below the 44% wide range reactor trip setpoint, and the reactor tripped on low level in steam generator No. 1.

As noted above, following the attempt to align the normal supply breaker for the A diesel generator to the bus, an attempt to manually align the diesel generator supply breaker was made. This attempt ultimately resulted in a trip of the diesel generator and opening of the diesel generator output breaker at 6:18 p.m. The indicated cause of the diesel generator trip was reverse power. In the previous summary, the diesel generator trip on reverse power that resulted when the operator attempted to close the diesel generator supply breaker remained unexplained, since neither of the predicted initiating causes for a reverse power trip appeared to have initiated the diesel generator trip. These predicted initiating causes are: bus voltage greater than the diesel generator output voltage and/or a manual trip of the diesel generator with the output breaker aligned to parallel the diesel generator with an offsite source.

Subsequent to the previous event summary, the licensee performed an engineering evaluation concerning the reverse power trip. During this evaluation, Protective Relaying and Control (PR&C) Technicians (utility nonlicensed) tested the under-frequency and reverse power relay. No abnormal condition was found that would have caused a spurious trip. However, it was found that the malfunction of the engineered safety features (ESF) load sequencer had started the diesel generator in the test mode by initiating a diesel generator start system (DGSS) (test) start and load shed of the bus. It is evident that the ESF load sequencer did not process a loss of power (LOP) signal, which would have put the DG in the emergency mode and sequenced the loads into the DG supplied bus. This failure was not a failure of the diesel generator but of the ESF load sequencer, which is not a part of the diesel generator system.

On December 17, 1985, a troubleshooting LOP start was performed from the ESF load sequencer in the BOP ESFAS cabinet. The diesel generator and the ESF load sequencer functioned properly. Also, the PR&C Technicians actuated the reverse power relay to determine if it would trip the DG in the emergency mode. The diesel generator did not trip. This retest satisfactorily proved that the

DG failure documented by the engineering evaluation was not an actual failure of the DG, but was a failure of the ESF load sequencer.

1.6 References

(1.1) 1. Toledo Edison Company, Docket 50-346, License Event Report 86-38-01, December 5, 1986.

(1.2) 2. Northern States Power, Docket 50-282, Licensee Event Report 86-06, October 8, 1986.

(1.3) 3. Commonwealth Edison Company, Docket 50-295, Licensee Event Report 86-35, October 10, 1986.

(1.4) 4. Florida Power Corporation, Docket 50-302, Licensee Event Report 85-24-02, June 9, 1986.

(1.5) 5. Arizona Public Service, Docket 50-528, Licensee Event Report 85-83-01, October 7, 1986.

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

2.0 EXCERPTS OF SELECTED LICENSEE EVENT REPORTS

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

This section of Power Reactor Events includes direct excerpts from LERs. In general, the information describes conditions or events that are somewhat unusual or complex, or that demonstrate a problem or condition that may not be obvious. The plant name and docket number, the LER number, type of reactor, and nuclear steam supply system vendor are provided for each event. Further information may be obtained by contacting the Editor at 301-492-4493, or at U.S. Nuclear Regulatory Commission, EWS-263A, Washington, DC 20555.

2.1 Closed Main Steam Pressure Instrument Isolation Valves Result in Pressure Transient and Reactor Scram

Perry Unit 1; Docket 50-440; LER 86-55; General Electric BWR

On September 2, 1986, at 1102, a reactor scram occurred due to an upscale trip on the intermediate range neutron monitors (IRMs). At the time of the event, the plant was in startup operation, the reactor power was approximately 3%, reactor pressure was 92 psig, feedwater flow was being controlled manually using the low flow controller; steam bypass valves 1 and 2 were full open, and valve 3 was 20% open. The B steam bypass and pressure regulator was selected for pressure control.

The transient started at 1100 when steam bypass and pressure control pressure transmitter 1C85-N001B suddenly sensed an increase in pressure of approximately 35 psi. (This sensed pressure increase remained constant for the duration of the event.) All seven steam bypass valves went full open, causing reactor pressure to decrease at approximately 10 psi per minute. Reactor pressure reached a minimum of 66 psig. The reduction in pressure caused a void formation increase and a subsequent increase in indicated reactor vessel water level.

The Supervising Operator reacted to the increase in reactor level by attempting to control the level increase by shutting the feedwater low flow control valve. Reactor level reached a maximum of +215 inches (above the top of active fuel) as indicated on the upset range level instrument. Concurrently, a second operator attempted to shut the steam bypass valves using the bypass jack decrease. (The steam bypass valves had been controlled manually using the steam bypass valve opening jack.) The operator actions failed to shut the bypass valves because the increased sensed pressure created an overriding automatic pressure control signal. The maximum combined flow limiter (which controls total steam flow to the main turbine and steam bypass valves) was decreased and was also incapable of overcoming the pressure control signal. The operator then increased the pressure setpoint for the automatic pressure control. As a result of this action, steam bypass valves 6 and 7 went shut and steam bypass valve 5 partially shut.

Since reactor pressure was still decreasing, the operator increased the pressure setpoint, further attempting to shut the steam bypass valves. This resulted in all steam bypass valves rapidly closing. Reactor pressure subsequently increased from 66 psig to 69 psig, causing a void collapse and a subsequent neutron flux spike. Seven of the eight IRMs reached the trip setpoint of 120/125 scale (Range 9) and properly actuated the reactor protection system (RPS), causing a reactor scram.

Because of the increase in steam flow caused by the steam bypass valves opening and the operator actions shutting the feedwater low flow control valve, reactor water level had decreased rapidly. Reactor level reached level 3 (+177.7 inches) as indicated on narrow range level instruments. This low level caused a second RPS actuation less than one second after the neutron flux scram. Reactor vessel level reached a minimum of +191 inches as indicated on wide range level instruments (<+165 inches narrow range). Operators restored level by further opening the feedwater low flow control valve. Control Room Operators took additional actions in accordance with Off-Normal Instruction (ONI)-C71, "Reactor Scram," and Plant Emergency Instruction (PEI)-B13, "Reactor Pressure Vessel Control." The plant was stabilized in hot shutdown at 1118. During the transient, flow oscillations caused the reactor water cleanup (RWCU) pumps to trip on low suction flow. The RWCU pumps were restarted at 1126.

The cause of the event was a sudden increase in sensed pressure on pressure transmitters (1C85-N001A, B) for steam bypass valve control. The transmitter isolation valves were subsequently found shut. The reasons for the increase in sensed pressure and the mispositioned instrument isolation valves are indeterminate. Earlier in the morning, the Control Room Operators questioned the steam pressure indication. A technician had been sent to check the position of the transmitter isolation valves. He reported that he could not move the valves; however, the valves appeared to be open. A work order had been initiated to repair the valves, but had not been issued to the field.

All work which was performed during the past year on or in the area of the transmitter isolation valves was reviewed and did not reveal any reason the isolation valves would have been shut. These valves were verified open on three separate occasions, the last being August 19, 1986. A final independent verification was scheduled to be performed by September 15, 1986. Operator action to reclose the steam bypass valves was hindered by the isolation of the pressure transmitter. Since the feedback signal of sensed pressure did not change as reactor pressure decreased, the steam bypass and pressure regulator system did not respond as expected. Thus, a slight adjustment of the pressure setpoint caused the steam bypass valves to rapidly shut.

The corrective actions which have been or will be completed are as follows:

(1) The pressure transmitter isolation valves were opened and verified open on September 2, 1986. Additionally, valve lineups for 150 instruments were conducted September 4. The valve lineups included a first and second check. One test connection valve was found out of its normal position. However, in this case there is a second test connection valve in the line which was shut and a cap on the end of the line. No other discrepancies were identified.

(2) Subsequent to the reactor scram, a work order was issued to troubleshoot the pressure regulators. A failed oscillator card in the A pressure regulator was found and replaced. This card did not contribute to the event because the B regulator was selected for control. With the exception of the above oscillator card, the pressure regulators were tested and calibrated satisfactorily on September 3, 1986.

(3) The operating instructions which use or make reference to the steam bypass and pressure regulator system were reviewed and compared with the vendor manual to ensure the system would be operated properly. Integrated Operating Instruction (IOI)-1 "Cold Startup," IOI-2 "Hot Startup," IOI-4 "Shutdown," IOI-6 "Cooldown-Main Condenser Not Available," IOI-7 "Cooldown Following a Reactor Scram Main Condenser Available," and System Operating Instruction (SOI)-C85 "Steam Bypass and Pressure Regulator System" have been enhanced to add a caution to identify possible system anomalies and to ensure that the bypass jack is used for pressure control during surveillances to test the steam bypass and pressure regulator system. The Control Room Operators have been trained to the above changes with an emphasis placed on system operation and expected indications.

(4) A memorandum was issued from the Perry Plant Operations Department (PPOD) Manager to all project personnel reemphasizing that only PPOD Instrument and Controls Section personnel are to operate instrument-related valves. Additionally, Plant Administrative Procedure (PAP)-0205 "Operability of Plant Systems" and PAP-0905 "Work Order Process" will be revised to include a caution to reenforce the operation of instrument-related valves by proper individuals only.

2.2 Inconsistency Between Safety Analysis and Technical Specifications Regarding Reactor Coolant Pump Operability During Control Element Assembly Withdrawal from Subcriticality

Millstone Unit 2; Docket 50-336; LER 86-10; Combustion Engineering PWR

While in the refueling mode on October 6, 1986, at 0815, an investigation by the licensee and Westinghouse (the nuclear steam system supplier) identified an inconsistency between the number of reactor coolant pumps required to be operating in hot standby, hot shutdown, and cold shutdown (Modes 3, 4, and 5) and the assumptions used in the safety analysis for control element assembly (CEA) withdrawal from subcriticality.

The cause of the inconsistency between the safety analysis and the technical specifications was the assumption that the hot zero power results for CEA withdrawal from a subcritical accident bounded Modes 3, 4, and 5. At hot zero power, all four reactor coolant pumps are required to be operating, while in Mode 3 only one reactor coolant pump is required to be operating, and in Modes 4 and 5 as little as one shutdown cooling loop is required to be operating. In addition, in Mode 3 at below 500 degrees F, plant procedures do not allow for the operation of all four reactor coolant pumps due to core uplift considerations.

The safety implication of the inconsistency between the safety analysis assumptions and the technical specification requirements for pump operability in Modes 3, 4, and 5 is that the design basis limit for the departure from nuclear boiling ratio (DNBR)(minimum DNBR $\geq$1.3) could be violated in the event of CEA withdrawal from subcriticality.

Administrative controls were installed to ensure that the control element drive mechanisms are deenergized with less than four reactor coolant pumps operating, thereby eliminating the potential for a CEA withdrawal accident for Modes 3 (when less than four reactor coolant pumps are operating), 4, and 5. In addition, Westinghouse re-performed the safety analysis for the CEA withdrawal from subcriticality to support a change to the technical specifications. On February 6, 1987, the licensee submitted a requested change to the technical specifications to incorporate the administrative control in a new limiting condition for operation and surveillance requirement. Westinghouse also reviewed the steam line break and CEA ejection accident analyses for Modes 3, 4, and 5, and determined that the hot zero power results for these accidents do bound Modes 3, 4, and 5.

2.3 Service Water Capability Less than Specified in FSAR Due to Inadequate System Design

Palisades; Docket 50-255; LER 86-36; Combustion Engineering PWR

On September 30, 1986, with the plant in cold shutdown condition, flow testing of the service water pumps (P-7A, P-7B and P-7C) revealed that the pumps were incapable of meeting flow/head values of 8000 gpm at 140 feet of head, per pump, as described in the plant's Final Safety Analysis Report (FSAR). The values attained during testing were 7330 gpm at 135 feet of head for P-7A, 7323 gpm at 134 feet of head for P-7B, and 7503 gpm at 136 feet of head for P-7C.

The three service water pumps are divided among two trains of safeguards equipment, with each train powered from a separate emergency diesel generator. When considering a postulated loss-of-coolant accident (LOCA), with a concurrent loss of offsite power and the failure of a single emergency diesel generator, the corresponding loss of either one or two service water pumps (depending on which train is assumed to fail) results in insufficient service water capability to the critical service water loads. Evaluation of the impact of the reduced flow on the ability of critical loads (containment air coolers VHX-1, 2, 3, and 4, component cooling water heat exchangers E-54A and B, engineered safeguards room coolers VHX-27A and B, control room HVAC VC-10 and 11, and emergency diesel generators 1-1 and 1-2) to fulfill their intended safety function is incomplete.

Additionally, during review of the service water system, the temperature of the service water was noted to have occasionally been higher than the 75 degrees F value assumed in the Palisades FSAR. Review of temperature data showed that it was not uncommon for service water temperatures to exceed 75 degrees F by several degrees during the summer months. On October 10, 1986, review of the data confirmed at least one occasion of previous plant operation (July 19, 1983 through August 5, 1983) with elevated service water temperature. The effect of elevated service water temperature reduces the cooling capability in a similar manner to that of reduced flow, and is being considered in the evaluation of the overall impact on critical components.

The original pump impellers supplied by the vendor (Layne-Bowler; service water pump model 67H-5605) had been modified by "backfiling" to improve performance. Subsequent replacement of the pump impellers (F-7A in 1980, P-7B in 1983 and P-7C in 1982) with impellers which were not similarly modified by the vendor was the primary cause of the reduced performance. Following replacement of the impellers, the testing which was performed was not sufficient to disclose the discrepancy. The cause of the error in the procurement process is not fully understood at this time.

During evaluation of the service water system, it was determined that without system modifications, anything less than a full compliment of three service water pumps results in insufficient service water capacity to satisfy design basis accident (DBA) loads, and is an apparent original plant design deficiency.

The assumption of 75 degrees F service water has been shown to be nonconservative for brief periods of time. While service water temperature was monitored, the potential significance of elevated service water temperature relative to the operability of critical loads was not previously recognized or addressed.

System flow testing and evaluation have resulted in a number of corrective actions to ensure that adequate cooling is available for critical components following a postulated DBA. Short term corrective actions completed include: (1) the isolation of containment air cooler VHX-4 upon a safety injection signal, (2) providing backup nitrogen supply to allow closing of the service water isolation valves to containment, (3) service water system flow balancing after backfiling the service water pump impellers, and (4) establishing a service water temperature limitation at a value below the currently assumed 75 degrees F value. Potential longer term corrective actions include: performing a more detailed analysis of heat load requirements for service water, automating isolation of service water to containment, insulating piping to reduce heat load, and increasing the capacity of engineered safeguards room cooler fans.

Periodic performance testing of the service water pumps to ensure that FSAR requirements continue to be satisfied will be evaluated for implementation.

Corrective action addressing the procurement process may be warranted pending evaluation of the errors involved.

The subject deficiencies discovered in the service water system, when combined with other discovered deficiencies in the component coolant water system, containment air cooling system, and low pressure safety injection system, constitute unanalyzed condition which compromised the plant's ability to adequately respond to a DBA.

2.4 Feedwater Pump Trip Due to Pressure Switch Out of Calibration

Catawba Unit 2; Docket 50-414; LER 86-38; Westinghouse PWR

On September 1, 1986, at 8:20 a.m., a generator zone A lockout occurred which was caused by a phase-to-phase short in the generator. Generator breakers A and B tripped and the turbine stop valves closed automatically. Main feedwater (MFW) flows to the steam generators (SGs) began to fluctuate. Rod control was placed in automatic to run back reactor power. MFW pump turbine (PT) B control was put in manual in an attempt to dampen the feedwater swings. At 8:30 a.m., a turbine trip signal occurred on loss of both MFW pumps, and an auxiliary feedwater (AFW) pump auto-start signal also occurred. Both motor driven AFW pumps were already running at this time to cool leaking check valves. The B MFW PT low flow alarm returned to normal; the SG D hi-hi level turbine trip alarm occurred; and MFW isolation occurred automatically on hi-hi level in SG D. At 8:32 a.m., the SG A hi-hi level turbine trip alarm occurred. By 8:35 a.m., the SG D and A hi-hi level turbine trip alarms returned to normal. At 8:36 a.m., MFWPT B was reset and then was started. At 8:42 a.m., the MFW isolation was reset and the valves were realigned to restore normal feedwater flow to the SGs.

The MFW system at Catawba provides condensate flow to the SG through four main feedwater lines. This flow is provided by two turbine driven pumps, each capable of providing at least 50% of required flow for the unit to operate at full power. Each of the four feedwater lines contains a feedwater control valve and a feedwater control bypass valve, which are modulated by the feedwater control system to maintain proper SG water level. The MFW control bypass valves normally control flow up to approximately 15% power, and the MFW control valves control flow from 15% to 100% power. These valves close on an MFW isolation signal, which is initiated by a hi-hi SG level of 78% narrow range. An MFW pump will trip on low suction flow of 3,000 gpm. A nuclear station modification (NSM) was implemented on May 14, 1986, to modify the MFW pump controls to open the MFW pump recirculation control valves, 2CF-6 and 2CF-13, on low MFW suction flows. This would prevent MFW pump trips on reactor trips and MFW isolations.

The feedwater swings which resulted in the MFWPT B trip on September 1 were initiated by the generator failure. However, per the NSM, MFW pump recirculation control valve 2CF-13 should have opened at 4500 gpm (decreasing) MFW pump suction flow to prevent MFWPT B from tripping. There is no evidence that 2CF-13 opened before MFWPT B tripped. Subsequent investigation revealed that the pressure switch (2CMPS5944) that reads suction flow and sends a signal to 2CF-13 was out of calibration. This resulted in 2CF-13 not opening to prevent the MFWPT B trip. The pressure switch was calibrated in May 1986, when the NSM was implemented. The pressure switch was subsequently recalibrated.

Immediately prior to the MFWPT B trip, MFWPT B discharge pressure reached approximately 1440 psig. The pump should have tripped at a discharge pressure of 1385 psig. A work request has been initiated to check and recalibrate as necessary all pressure switches in the high discharge pressure trip logic for both MFWPTs. Also, a work request has been initiated to check and recalibrate as necessary all pressure switches in the low suction flow logic for both MFWPTs.

2.5 Licensee Discovery of Discrepancy in Bounding Power Shape

Maine Yankee; Docket 50-309; NRC/NRR Safety Evaluation (1/6/87); Combustion Engineering PWR

On September 2, 1986, the NRC was informed by the licensee for Maine Yankee that, during reload analyses, it had been discovered that the highly peaked axial power shape used in the plant's large break loss-of-coolant accident (LOCA) analyses since 1977 is not the bounding shape. Appendix K to 10 CFR Part 50 requires that the axial shape which results in the most severe consequences should be used in the emergency core cooling system (ECCS) evaluation model LOCA calculations. It was determined that at Maine Yankee the bounding shape is a flattened shape which results in higher peak cladding temperatures, especially later in the life of the reload. For the balance of Cycle 9, administrative limits on power peaking factors are being implemented to assure that results of LOCA analyses done with the current model comply with the limits of 10 CFR 50.46. For Cycle 10, the licensee has proposed changes in their approved ECCS evaluation model to recover the margin lost by utilizing the more severe flattened axial shape. The modifications, review, and analysis will be a two-step process. The changes involve the selection of appropriate power shapes, and modification of the injection ΔP penalty.

The licensee has proposed a method for selecting appropriate radial and axial power distributions to be used in LOCA analyses to assure compliance with paragraph I.A. of Appendix K, 10 CFR Part 50, which states:

> A range of power distribution shapes and peaking factors representing power distributions that may occur over the core lifetime shall be studied and the one selected should be that which results in the most severe calculated consequences, for the spectrum of postulated breaks and single failures analyzed.

Power shapes must also be selected so as not to violate specified acceptable fuel design limits (SAFDLs), and they must also be calculated based on nuclear design parameters and possible operating conditions for the particular cycles under consideration. The radial power distribution (maximum pin power) is determined for a variety of cycle conditions for thermal margin considerations. The maximum value is selected for the hot-test pin in the LOCA analysis. The corresponding radial power for the hot assembly is selected, and all uncertainties are included to maximize hot pin, hot assembly, and average core power which are used in LOCA analysis.

With the pin power established for all LOCA analyses as a single maximum value, several axial shapes are next selected for thermal margin based on core power and symmetric offset considerations. This results in a symmetric offset curve of linear heat generation rate (LHGR) versus core height. This curve results in fairly limiting kW/ft values at elevations below the mid plane.

Using a representative selection of axial power shapes determined for the thermal analysis, several large break LOCA analyses are performed to assure compliance with 10 CFR 50.46 and Appendix K. It is verified that these shapes include flatter, more symmetric shapes than were previously considered. LOCA analyses performed with this set of axial power shapes result in a LOCA limit curve which is more limiting than the thermal margin curve at higher elevations. At lower elevations the thermal margin curve is so clearly limiting that bottom peaked LOCA analyses are not required. This is particularly true since periods of core uncovery for both large and small breaks are much longer at higher elevations, thus making top skewed or symmetric power shapes more limiting than bottom skewed for LOCA analysis.

Appropriate monitoring is performed to verify that the radial and axial components of power distribution are maintained below the limiting values as described above.

Section I.D.4 of Appendix K to 10 CFR Part 50 requires that the thermal-hydraulic interaction between steam and all emergency core cooling water shall be taken into account when calculating core reflooding rates. The currently approved emergency core cooling system (ECCS) evaluation model for Maine Yankee utilizes an additional frictional pressure drop (ΔP penalty) to account for the steam-water interaction effect. A ΔP penalty of 1.5 psid is utilized during the accumulator injection period; a penalty of 0.8 psid is used during the pumped injection phase. The licensee has proposed to modify the ECCS evaluation model for Maine Yankee by reducing the ΔP penalty from 0.8 psid to 0.15 psid during the pumped injection phase.

2.6 Corrosion-Induced Failure of Containment Relief Line Isolation Valve

Fermi Unit 2; Docket 50-341; LER 86-27; General Electric BWR

At 1115 hours on August 31, 1986, Fermi Unit 2 was in startup operation at 510 degrees F, 715 psig, and 1.4% reactor power. During performance of a monthly technical specification operability check for the suppression pool relief line isolation valves, a butterfly isolation valve (Jamesbury, Model No. 8922EX-A, 20" dia.) in the relief line was closed and could not be reopened.

The operability check measured valve stroke times, and verified operation of the valve position status lights in the main control room. The inability of the isolation valve to be reopened was immediately recognized by control room personnel (utility, licensed) based on control room status light indication of valve position.

There are two suppression pool vacuum relief lines. Each of these lines consists of a normally closed, fail open, air-operated butterfly isolation valve, and a downstream self-actuating vacuum breaker valve. Each vacuum relief line is sized to provide adequate suppression pool venting without requiring use of the opposite relief line.

The suppression pool vacuum relief lines are designed to prevent an excessive negative pressure condition in the suppression pool, relative to reactor building (secondary containment) pressure. The relief line isolation and vacuum breaker valves will automatically open on a high suppression pool vacuum condition, or can be manually opened from the main control room to allow air from the reactor building into the suppression pool.

Technical Specifications require that the suppression pool vacuum relief lines be operable, and closed when operating at, or above, hot shutdown. In addition, the lines also must be capable of being opened. When the lines are not capable of being opened, they must either be restored within 72 hours, or a plant shutdown must be initiated.

Failure of the isolation butterfly valve in the closed position made the associated vacuum breaker relief line incapable of being opened. Since the failed valve was not anticipated to be restored to an OPERABLE status within the allowed 72-hour action statement interval, a plant shutdown was initiated prior to action statement expiration at 1800 hours on September 2, 1986. Hot shutdown was achieved at 0923 hours on September 3, 1986, and cold shutdown was achieved on September 3, 1986. The NRC Operations Center was notified of the plant shutdown on September 3.

In addition to performing a vacuum relief function when in the open position, the failed valve also performs a primary containment isolation function when closed. Although the butterfly valve had failed in the closed position, no isolation capabilities could be credited for the valve because it was inoperable. In response to the loss of operability for the butterfly valve, the affected containment penetration was closed at 1512 hours on August 31, 1986 by deactivating the suppression pool to reactor building relief line check valve.

After verifying that the air operator for the failed isolation valve was operating satisfactorily, the operator was removed and an unsuccessful attempt to open the valve with a wrench was made. The valve was then disassembled for inspection, and repaired.

During valve disassembly, force was required to remove the seized valve shaft. Once the shaft was removed, the NOMEX bottom shaft bearing was observed to have failed. The bearing was galled and distorted, and the carbon steel valve disc and shaft were noted to be corroded. The carbon steel disc and shaft were replaced with stainless steel components, and the shaft bearing was replaced on September 5, 1986.

The failed valve is located immediately outside the suppression pool, and is in direct contact with the high humidity environment of the suppression pool. This service environment resulted in corrosion of the carbon steel internal valve components.

Corrosion-related problems had previously been noted on the similarly manufactured butterfly valve in the opposite suppression pool vacuum breaker relief line, and in a similarly manufactured butterfly valve in a containment purge isolation line. At the time that these two valves were repaired, the corrosion was not realized to be a potential concern for other valves. Both of the affected valves are isolation valves, and were exposed to a high humidity environment.

The purge isolation valve was repaired with stainless steel components. However, the suppression pool vacuum breaker isolation valve associated with the opposite suppression pool vacuum relief line was repaired with carbon steel internals. With the exception of the vacuum breaker isolation valve, no other isolation valves of similar design and manufacture have been identified which are directly exposed to the humid suppression pool environment, and which still have carbon steel internals.

Immediately prior to the isolation valve seizure, the valve was stroke timed with unsatisfactory results. The valve was then restroked, again with unsatisfactory results. The valve seized during the third attempt to stroke the valve.

Stroke time data for the failed isolation valve had been recorded and periodically reviewed prior to the failure. This review ensured that there was not an increase in stroke time of 25% or greater over the last previously measured stroke time.

The stroke time data from previous performances never exceeded the criteria for allowable increase in stroke time. However, when the previous stroke time data for the valve was plotted and reviewed after the event, it was noted that there had been a progressive degradation in stroke time performance over a period of several months.

As corrective actions, the carbon steel disc and shaft were replaced with stainless steel components, and the shaft bearing was replaced. In addition, plotting and review of the stroke time data for similarly designed and manufactured valves which are directly exposed to high humidity environments has been performed, and will continue to be performed to detect negative stroke time trends prior to valve failure.

2.7 High Pressure Coolant Injection System Valve Failure Due to Procedural Inadequacy

FitzPatrick; Docket 50-333; LER 86-14; General Electric BWR

At 2200 on September 3, 1986, while the plant was operating at full power, the reactor core isolation cooling (RCIC) system was declared inoperable due to oscillating readings from a RCIC high steam flow sensor. As a result, the surveillance test, "High Pressure Coolant Injection (HPCI) Flow Rate/HPCI Pump Operability/HPCI Valve Operability Test F-ST-4B," was initiated to verify HPCI operability. At 2205, the circuit breaker for the valve HPCI torus suction to HPCI, 23MOV-58, tripped when given an open signal from the control room. A second attempt to open the valve, after resetting the breaker, was unsuccessful. The HPCI system was declared inoperable and the plant entered a 24-hour limiting condition of operation (LCO) due to the inoperability of the HPCI and RCIC systems.

An investigation into the valve inoperability was commenced by the Maintenance Department. Concurrently, the RCIC system high steam flow sensor was replaced. RCIC operability tests were completed at 0916 on September 4, 1986, and RCIC was declared operable. The plant was now in a 7-day LCO due to the HPCI inoperability.

Disassembly of the valve actuator and motor revealed a motor insulation failure due to overheating. There was no evidence of other mechanical or electrical problems in either the motor or actuator.

The motor was replaced and tested satisfactorily. HPCI operability testing was completed at 0415 on September 5, 1986, and HPCI declared operable. The modification format was utilized because the replacement motor had a slightly higher output torque, and an engineering review was judged necessary. An investigation into the root cause of the motor failure was initiated.

Earlier on September 3, 1986, at 1355, a semi-annual surveillance test, "HPCI Subsystem Logic System Functional Test," had been completed. Valve 23MOV-58 had been cycled as part of this test. Examination of the procedure details revealed that, due to a combination of direct stroking and stroking due to the operation of associated relaying, the valve stroked eight times within a 20- to 30-minute period. The surveillance test requires three close operations and three open operations during its performance, for a total of six strokes. During the last valve stroking of the surveillance test, the breaker tripped. The valve was then cycled, after resetting the breaker, to verify operability. This breaker trip is now judged to have been an indication of motor degradation.

The failed motor was a 125 V, 7.5 foot-lb torque, 0.5 horsepower dc motor with a 5-minute (intermittent) duty rating. The stroke time for this valve is approximately 60 seconds. Discussions with the actuator's manufacturer, Limitorque, revealed that this type of motor can be continuously stroked three to four times without danger of overheating. Stroking beyond this would lead to insulation degradation, and eventual failure of the motor. It was judged, based on these discussions, that a direct correlation between the number of excess strokes that the valve was subjected to, and the actual time of motor failure, could not be made. However, insulation degradation, once begun, would lead to premature motor failure.

A review of this valve's maintenance history revealed three previous motor failures of a cyclic nature (approximately 18 months apart) that can be attributed to overheating. These previous failures and the current one are believed to have the same root cause, that is, the number of cycling operations conducted in a short time.

It is noted that these motors have not failed every time surveillance test F-ST-4E, has been performed. This is evidence that the number of strokes performed do not lead to a catastrophic motor failure, but rather a long term insulation degradation leading to motor failure. It is also noted that the valve duty while performing this surveillance test is more severe than the duty required while performing its safety function. The normal source of water to the HPCI pump is from the condensate storage tanks. Upon low level in these tanks, the source of water to the HPCI pump is taken from the suppression pool. Valve 23MOV-58, closed when the condensate storage tanks are being utilized, would open when using the suppression pool as a supply. This service is considerably less severe than during the surveillance test, and it is judged that a motor design problem does not exist.

The following corrective actions are being performed:

(1) An engineering analysis is being made to confirm that the operator's size, configuration and switch settings are adequate.

(2) Operations is reviewing surveillance tests to identify other dc motor-operated valves subject to similar excessive stroking. Potential problems identified by this review will be resolved by procedural change or engineering review, as appropriate.

(3) Valve 23MOV-57, another similar HPCI system valve/actuator, was also subject to surveillance test F-ST-4E. The valve was stroked several times to verify operability; however, the actuator shall be disassembled and examined during the next scheduled outage.

3.0 ABSTRACTS/LISTINGS OF OTHER NRC OPERATING EXPERIENCE DOCUMENTS

3.1 Abnormal Occurrence Reports (NUREG-0090) Issued in September-October 1986

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

Date Issued	Report
9/86	REPORT TO CONGRESS ON ABNORMAL OCCURRENCES, JANUARY-MARCH 1986, VOL. 9, NO. 1

There were seven abnormal occurrences at NRC licensees during the period. Two occurred at licensed nuclear power plants, one occurred at a fuel cycle facility other than a power plant, and four occurred at other licensees (industrial radiographers, medical institutions, industrial users, etc.).

The occurrences at the plants involved: (1) the loss of power and water hammer event at San Onofre Unit 1, and (2) the loss of integrated control system power and overcooling transient at Rancho Seco.

The occurrences at the fuel cycle facility involved the rupture of a uranium hexaflouride cylinder and release of gases at the Sequoyah Fuels Corporation's Sequoyah Facility near Gore, Oklahoma.

The occurrences at other licensees involved: (1) a therapeutic medical misadministration at Washington Hospital Center, Washington, DC; (2) the overexposure to a member of the public from an industrial guage which had been licensed to C-E Glass, Inc., a Division of Combustion Engineering, Inc.; (3) a breakdown of management controls at an irradiator facility (Radiation Technology, Inc., of Rockaway, New Jersey); and (4) a tritium overexposure and laboratory contamination at Ferris State College, Big Rapids, Michigan.

In addition to the occurrences at NRC licensees, the following occurred at Agreement State licensees: (1) the radiation injury of an industrial radiographer employed by BF Inspection Services, Texas; (2) the contamination of a scrap steel facility (Tamco Steel Company, Ontario, California; (3) the radiation injury of an industrial radiographer employed by Boothe-Twining, Inc., at a field site in the Kern River oil field in Bakersfield, California; and (4) the radiation injury of an industrial assistant radiographer employed by Basin Industrial X-Ray, Odessa, Texas.

Also, the report updated information on: (1) the nuclear accident at Three Mile Island (79-3), first reported in Vol. 2, No. 1, January-March 1979; (2) loss of the main and auxiliary feedwater systems at Davis-Besse (85-7), first reported in Vol. 8, No. 2, April-June 1985; (3) a breakdown in management controls at the Pittsburgh Testing Laboratory's Cleveland, Ohio Facility (85-10), first reported in Vol. 8, No. 2, April-June 1985; (4) management control deficiencies at LaSalle (85-12), first reported in Vol. 8, No. 3, July-September 1985; (5) inoperable steam generator low pressure trip at Maine Yankee (85-13), first reported in Vol. 8, No. 3, July-September 1985; (6) management deficiencies at Tennessee Valley Authority (85-14), first reported in Vol. 8, No. 3, July-September 1985; and (7) management deficiencies at the Fermi Station (85-20), first reported in Vol. 8, No. 4, October-December 1985.

In addition, items of interest that did not meet abnormal occurrence criteria but may be considered significant by the public involved: (1) the failure of a lifting rig attachment while lifting an upper guide structure at St. Lucie Unit 1; (2) degraded reactor coolant pump shafts at Crystal River Unit 3; (3) an earthquake in the vicinity of the Perry Nuclear Plant; and (4) inoperability of the standby liquid control system at Vermont Yankee.

3.2 Bulletins and Information Notices Issued in September-October 1986

The Office of Inspection and Enforcement periodically issues bulletins and information notices to licensees and holders of construction permits. During the period, two bulletins, 13 information notices, and two information notice supplements were issued.

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 (Atomic Industrial Forum, Institute of Nuclear Power Operations, nuclear steam suppliers, vendors, etc.), a technique which has proven effective in bringing faster and better responses from licensees. Bulletins generally require one-time action and reporting. They are not intended as substitutes for revised license conditions or new requirements.

Information Notices are rapid transmittals of information which may not have been completely analyzed by 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.

Bulletin	Date Issued	Title
86-03	10/8/86	POTENTIAL FAILURE OF MULTIPLE ECCS PUMPS DUE TO SINGLE FAILURE OF AIR-OPERATED VALVE IN MINIMUM FLOW RECIRCULATION LINE (Issued to all facilities holding an operating license or construction permit)
86-04	10/29/86	DEFECTIVE TELETHERAPY TIMER THAT MAY NOT TERMINATE TREATMENT DOSE (Issued to all NRC licensees authorized to use cobalt-60 teletherapy units)
86-05 Sup. 1	10/16/86	MAIN STEAM SAFETY VALVE TEST FAILURES AND RING SETTING ADJUSTMENTS (Issued to all power reactor facilities holding an operating license or construction permit)
86-25 Sup. 1	10/15/86	TRACEABILITY AND MATERIAL CONTROLS OF MATERIAL AND EQUIPMENT, PARTICULARLY FASTNERS (Issued to all power reactor facilities holding an operating license or construction permit)
86-78	9/2/86	SCRAM SOLENOID PILOT VALVE (SSPV) REBUILD KIT PROBLEMS (Issued to all BWR facilities holding an operating license or construction permit)

Information Notice	Date Issued	Title
86-79	9/2/86	DEGRADATION OR LOSS OF CHARGING SYSTEMS AT PWR NUCLEAR POWER PLANTS USING SWING-PUMP DESIGNS (Issued to all power reactor facilities holding an operating license or construction permit)
86-80	9/12/86	UNIT STARTUP WITH DEGRADED HIGH PRESSURE SAFETY INJECTION SYSTEM (Issued to all power reactor facilities holding an operating license or construction permit)
86-81	9/15/86	BROKEN INNER-EXTERNAL CLOSURE SPRINGS ON ATWOOD & MORRILL MAIN STEAM ISOLATION VALVES (Issued to all power reactor facilities holding an operating license or construction permit)
86-82	9/16/86	FAILURES OF SCRAM DISCHARGE VOLUME VENT AND DRAIN VALVES (Issued to all power reactor facilities holding an operating license or construction permit)
86-83	9/19/86	UNDERGROUND PATHWAYS INTO PROTECTED AREAS, VITAL AREAS, MATERIAL ACCESS AREAS, AND CONTROLLED ACCESS AREAS (Issued to all power reactor facilities holding an operating license or construction permit, and fuel fabrication and processing facilities)
86-84	9/30/86	RUPTURE OF A NOMINAL 40-MILLICURIE IODINE-125 BRACHYTHERAPY SEED CAUSING SIGNIFICANT SPREAD OF RADIOACTIVE CONTAMINATION (Issued to all NRC medical institution licensees)
86-85	10/3/86	ENFORCEMENT ACTIONS AGAINST MEDICAL LICENSEES FOR WILLFUL FAILURE TO REPORT MISADMINISTRATIONS (Issued to all medical licensees)
86-86	10/10/86	CLARIFICATION OF REQUIREMENTS FOR FABRICATION AND EXPORT OF CERTAIN PREVIOUSLY APPROVED TYPE B PACKAGES (Issued to all registered users of NRC certified packages)
86-87	10/10/86	LOSS OF OFFSITE POWER UPON AN AUTOMATIC BUS TRANSFER (Issued to all power reactor facilities holding an operating license or construction permit)
86-88	10/15/86	COMPENSATORY MEASURES FOR PROLONGED PERIODS OF SECURITY SYSTEM FAILURES (Issued to all power reactor facilities holding an operating license or construction permit)
86-89	10/16/86	UNCONTROLLED ROD WITHDRAWAL BECAUSE OF A SINGLE FAILURE (Issued to all BWR facilities holding an operating license or construction permit)

3.3 Case Studies and Engineering Evaluations Issued in September-October 1986

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 investigative 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
E611	10/16/86	DEFICIENCIES IN SEISMIC ANCHORAGE FOR ELECTRICAL AND CONTROL PANELS

This engineering evaluation report concerned events involving inadequate anchorage of electrical and control panels. The report specifically addresses recent events at Cooper, Dresden Units 2 and 3, and Davis-Besse. The initial case was at Davis-Besse, where cabinet doors on Cyberex class 1E equipment for essential instrument 120 V ac power were found to lack the required door bolts. The second event concerned emergency diesel generator switchgear cabinets at Cooper that were not fastened to embedded channels beneath the cabinets. The third and most extensive deficiency was found at Dresden Unit 2, where it was determined that the control room control panels did not have positive anchorage to the floor. In each instance, the deficiency had existed since plant construction and was the result of installation errors, since the design drawings had specified seismic anchorage.

As a consequence of these events, this engineering evaluation was initiated to determine the extent of other similar deficiencies, regulatory requirements,

Engineering Evaluation	Date Issued	Subject
E611 (Cont'd)		history of addressing the question of seismic anchorage for electrical equipment, and the safety considerations of the deficiencies.

It was found that the problem has been a generic regulatory concern since 1980, when Information Notice (IN) 80-21 was published, and the issue was designated Unresolved Safety Issue (USI) A-46, "Seismic Qualification of Equipment in Operating Nuclear Power Plants." The 1980 Information Notice specifically suggested that licensees should perform walk-through inspections of the anchorage systems of certain specified categories of equipment, including electrical cabinets and control panels. In spite of IN 80-21 and independent walk-through inspections related to seismic anchorage of equipment at certain plants by different groups, the lack of seismic anchorage for electrical and control panels continues to be identified, including in some cases gross inadequacies. The near-term resolution of USI A-46 is aimed in part at remedying these residual defects.

A generic letter is to be issued requiring walk-through inspections of operating nuclear plants using detailed generic checklists and procedures to verify the adequacy of seismic anchorage for all equipment necessary to accomplish and maintain safe, hot shutdown. Consequently, that solution appears to be adequate to assure that the issue is thoroughly addressed. However, in light of the evidence of continuing deficiencies, this evaluation suggested that: (1) the Office of Inspection and Enforcement issue an updated IN characterizing recently identified deficiencies in order to emphasize the need to respond expeditiously to the generic letter to complete the reinspections, and to correct the deficiencies thus identified; and (2) the Office of Nuclear Reactor Regulation modify the generic letter to require near-term walkdown of critical equipment to verify the absence of gross deficiencies before the planned detailed inspections.

3.4 Generic Letters Issued in September-October 1986

Generic letters are issued by the Office of Nuclear Reactor Regulation, Division of Licensing. They are similar to IE Bulletins (see Section 3.2) in that they transmit information to, and obtain information from, reactor licensees, applicants, and/or equipment suppliers regarding matters of safety, safeguards, or environmental significance. During September and October 1986, three letters were issued.

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

Generic Letter	Date Issued	Title
86-15	9/22/86	INFORMATION RELATING TO COMPLIANCE WITH 10 CFR 50.49, "EQ OF ELECTRICAL EQUIPMENT IMPORTANT TO SAFETY" (Issued to all licensees and applicants for an operating license)
86-16	10/22/86	WESTINGHOUSE ECCS EVALUATION MODELS (Issued to all PWR licensees and applicants)
86-17	10/17/86	AVAILABILITY OF NUREG-1169, "TECHNICAL FINDINGS RELATED TO GENERIC ISSUE C-8; BOILING WATER REACTOR MAIN STEAM ISOLATION VALVE LEAKAGE AND LEAKAGE TREATMENT METHODS" (Issued to all BWR licensees and applicants)

3.5 Operating Reactor Event Memoranda Issued in September-October 1986

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

No OREMs were issued during September-October 1986.

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

The monthly 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.

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