Reference 10

CURRENT EVENTS

POWER REACTORS

REGULATORY
COMMISSION

THIS COMPILATION OF SELECTED EVENTS IS PREPARED TO DISSEMINATE INFORMATION ON OPERATING EXPERIENCE AT NUCLEAR POWER PLANTS IN A TIMELY MANNER AND AS OF A FIXED DATE. THESE EVENTS ARE SELECTED FROM PUBLIC INFORMATION SOURCES. NRC HAS, OR IS TAKING CONTINUOUS ACTION ON THESE ISSUES AS APPLICABLE, FROM AN INSPECTION AND ENFORCEMENT, LICENSING AND GENERIC REVIEW STANDPOINT.

1 SEPTEMBER - 31 OCTOBER 1977

(PUBLISHED DECEMBER 1977)

OPERATOR ERROR

On January 11, 1977 while the Fort Calhoun Station Unit 1 was operating, water from the Refueling Water Storage Tank was pumped into the containment through the containment spray header due to an operator error.

During the performance of a quarterly test of the safety injection and containment spray pumps, the operator noticed an increase in the containment sump level approximately ten minutes after the low pressure safety injection pump had been started. Approximately 3300 gallons of water had been pumped to the containment. About one minute later the ventilation isolation actuation signal was received. At this time the operator realized he had failed to follow the surveillance procedures and had left the discharge valve of the low head safety injection pump open. He immediately secured the pump.

The Reactor Coolant System was checked for leakage and containment entry was made approximately one hour later. Inspection revealed that a discharge from the containment spray nozzles had occurred. A few minutes later power reduction was started. A second containment entry was made about an hour later, after containment air samples confirmed that a full face mask would provide adequate respiratory protection for the levels of radioactivity in the building. A detailed inspection revealed no serious deficiencies and no electrical grounds; the power reduction was terminated at a power level of 83%.

Although the operator had not followed the procedure and the discharge valve was open, the containment spray header isolation valve (HCV-345) and the low pressure safety injection to containment spray header cross-connect valve (HCV-335) should have prevented the event. The electric/pneumatic converter on HCV-345 had failed and both red and green position indication lights were on, indicating the valve was partially open. Prior to the event the auxiliary Building Equipment Operator had taken local control of the valve in an attempt to completely close the valve. After about 1/2 inch of stem travel, the operator removed the valve pin and the valve went back to its previous position as demanded by the valve positioner. The third valve (HCV-335) in the incident had a leakage problem that had been previously identified but no corrective action had been taken.

The pneumatic relay on valve HCV-345 was replaced and valve HCV-335 repaired. Valve HCV-344 and HCV-345 are now required to be placed in the test mode prior to operating the low pressure safety injection pump or contain spray pump for testing. This mode along with verification of an annunciator will ensure that both of these valves are in the fully closed position prior to pump operation.[1]

VALVE MALFUNCTIONS

1. Primary System Depressurization

On September 24, 1977, Davis Besse Nuclear Power Station Unit No. 1 experienced a depressurization when a pressurizer power relief valve failed in the open position. The Reactor Coolant System (RCS) pressure was reduced from 2255 psig to 875 psig in approximately twenty-one (21) minutes. At the beginning of this event, steam was being bypassed to the condenser and the reactor thermal power was at 263 MW, or 9.5%. Electricity was not being generated. The following systems malfunctioned during the transient:

a. Steam and Feedwater Rupture Control System (SFRCS).

b. Pressurizer Pilot Actuated Relief Valve.

c. No. 2 Steam Generator Auxiliary Feed Pump Turbine Governor.

The event was initiated at 2134 hours, when a spurious "half-trip" occurred in the SFRCS, resulting in closure of the No. 2 Feedwater Startup Valve and loss of flow to No. 2 Steam Generator. Approximately one minute later, low level in the No. 2 Steam Generator caused a full SFRCS trip, closing the Main Steam Isolation Valves

(MSIV). The loss of heat sink for the reactor caused the RCS temperature, pressure, and pressurizer level to rise.

The RCS pressure increased to the pilot actuated relief valve setpoint (2255 psig) and the valve cycled open and closed nine times in rapid succession, failing to close on the tenth opening. Meanwhile, the reactor operator observed the pressurizer level increase and manually tripped the reactor about one minute after MSIV closure (two minutes into the transient). At this point the RCS pressure was approximately 2000 psig and decreasing while the pressurizer level had reached its maximum initial rise of about 310 inches. The RCS pressure continued to decrease due to the open relief valve and upon reaching 1620 psig approximately three minutes into the transient, actuated Safety Features including high pressure (water) injection and containment isolation.

Approximately five minutes into the transient the rupture disc on the pressurizer quench tank, which was receiving the RCS blowdown, burst. Bursting of the rupture disc was aggravated by the actuation of containment isolation, which had isolated the quench tank cooling system, resulting in expedited pressurization of the quench tank.

The RCS continued to blow down through the open pressurizer power relief valve and the quench tank rupture disc opening until primary coolant saturation pressure was reached, about six minutes into the transient. The formation of steam in the RCS caused an insurge of water into the pressurizer. This insurge and the high pressure water injection then restored pressurizer level to about 310 inches after nine minutes into the transient.

Approximately thirteen minutes into the transient, the secondary side of the No. 2 Steam Generator went dry. About fourteen minutes into the transient, the operators noticed the low level condition and found that the auxiliary feed pump was operating at reduced speed. Manual control of the auxiliary feed pump was started and water level restored to the No. 2 Steam Generator.

At approximately 21 minutes into the transient, the operators discovered that the pressurizer power relief valve was stuck open. Blowdown via this valve was stopped by closing the block valve, thus terminating the reactor vessel depressurization. The RCS pressure recovered to normal and cooldown of the system followed.

The reason for the spurious "half-trip" of the SFRCS has not yet been determined. An extensive investigation revealed several loose connections at terminal boards, but nothing conclusive.

Investigation into the failure of the pressurizer pilot actuated relief valve revealed that a "close" relay was missing from the control circuit. This missing relay would normally provide a "seal-in" circuit which would hold the valve open until the pressure dropped to 2205 psig. Without the relay the power relief valve cycled open and closed each time the pressure of the RCS went above or below 2255 psig. The rapid cycling of the valve caused a failure of the pilot valve stem, and this failure caused the power relief valve to remain open.

It was determined that the auxiliary feed pump did not go to full speed because of "binding" in the turbine governor.

The transient was analyzed by the NSSS vendor and determined to be within the design parameters analyzed for a rapid depressurization.

With exception of the above noted malfunctions, the plant functioned as designed and there was no threat to the health and safety of the general public.[2-3]

2. Feedwater Isolation Valves

On two occasions in July, at the Trojan nuclear plant, a hydraulic feedwater isolation valve failed to close upon receipt of a close signal. All other equipment required to operate, functioned normally.

The first failure, July 6, 1977, had been attributed to an improperly assembled solenoid in the hydraulic actuator. Investigation of the second failure indicated that both events were due to a lack of sufficient hydraulic pressure.

Failure of the valve to close was caused by the pressure regulator leaking and failing to close down to regulate the pressure. This caused the hydraulic system on the valve to be drained down to a point that the valve would not operate. Inspection of the regulator revealed that a locking screw on the regulator adjusting knob was loose and would allow the knob to vibrate to any position. With the regulator improperly set it would not close down to regulate pressure and would allow the hydraulic fluid to drain before the hydraulic operator could function. A similar problem was discovered on two other valves, although the maladjustment was not sufficient to prevent these valves from operating.

All of the regulators were reset and the adjusting knobs were locked in place so that they could not vibrate loose. The isolation valves were tested satisfactorily following these adjustments.[4]

3. Off-Gas System Valves

At the Oyster Creek nuclear generating station on August 27, 1977, the reactor building ventilation system isolated and the standby gas treatment system (SGTS) automatically initiated.

Investigation revealed that at approximately 1850 hours a station employee performing housekeeping duties in the main control room accidently caused the augmented off gas (AOG) mode switch to move from "isolate and bypass" to the "isolate" position. This resulted in the off gas valve and the off gas drain valve going closed, and since the AOG was not in service the gas flow was stopped. The isolation of the reactor building ventilation system and initiation of the SGTS occurred at 1905. The two off gas valves were opened four minutes later and the SGTS was secured. The reactor building ventilation system was returned to normal at 2000 hours.

The off gas drain valve did not seat properly and was not leak tight. This condition allowed the gaseous radioactivity within the isolated off gas system piping to travel up through the stack sump in the stack base and fill the air space in the ventilation tunnel. When the radiation level in the reactor building ventilation duct reached a level of 17 mr/hr the monitors located next to this duct initiated the SGTS.

The safety concern associated with this event is the possibility of a submergence dose a person would have received from the radioactive gaseous atmosphere if they were in the tunnel area. The atmosphere in the tunnel area is processed through the radwaste ventilation system, which contains both roughing and absolute filters, prior to exhausting through to the stack which is monitored. The maximum radiation level sensed in the tunnel was 26 mr/hr.

No personnel exposures or releases to the environment resulted from this event. The licensee is investigating the feasibility of installing an alarm to alert operations personnel to the closure of the off gas valve when the AOG is out-of-service.[5]

SMALL PIPE BREAK ANALYSIS

On June 9, 1977, an orderly shutdown of the Yankee Nuclear Power Station (Yankee Rowe), a pressurized water reactor, was initiated by the licensee because of an error discovered in the Emergency Core Cooling System (ECCS) performance analysis.

Yankee Atomic Electric Company (YAEC), the licensee, notified the Nuclear Regulatory Commission (NRC) that an error had been discovered in a particular small break loss of coolant accident (LOCA) analysis, which permitted reactor operation with Core XII in a manner less conservative than assumed in the original analysis.

While performing a review of the analyzed small break accidents for the Core XIII reload, the YAEC Safety Analysis Group determined on June 7, 1977 that an incorrect fluid flow resistance calculation was made in the safety injection line break analysis. The fluid flow characteristics study had taken credit for the 2-1/4 inch safety injection line thermal sleeve to retard spillage from the accumulator -- a tank which supplies borated water to the reactor core in the event of a reactor coolant system pipe break. The flow resistance of the sleeve should not have been included in the flow calculation, as a new worst case pipe break was identified in a 4-inch diameter line section.

The recomputed decreased flow resistance allowed increased accumulator flow to be calculated for the break, and decreased the ECCS supply pressure to less than had been assumed, thus decreasing the core reflood capability of the ECCS. This corrected flow resistance assumption was used for the accident analysis of the present core, Core XII, which was operating at 79% of rated power in a coastdown program prior to the June 9, 1977 shutdown. Operation of the reactor with Core XII commenced in December 1975.

Upon discovering the error, the licensee reduced power level to 300 megawatts thermal (50% rated power), which was believed to conservatively accommodate the analysis error. During subsequent analysis, however, the licensee was unable to assure himself that the 10 CFR 50.46 limits on peak fuel cladding temperature could be maintained for the postulated small break. Therefore, the facility was shutdown pending resolution of this matter and to proceed with the Core XIII refueling outage which had been previously scheduled to commence on July 2, 1977.

The licensee subsequently performed an approximate best estimate analysis of the postulated worst case small pipe break, which included assumptions based on actual facility equipment availability during Core XII operation. The results of this analysis indicated that the calculated peak fuel cladding temperature was well below 10 CFR 50.46 limits. The more conservative 10 CFR 50 Appendix K reanalysis of Core XII operation, however, indicated that 10 CFR 50.46 limits might have been exceeded in the event that the safety injection pipe break had actually occurred.

Prior to returning the plant to operation after refueling of Core XIII the licensee: 1) performed flow measurements tests to determine the actual flow resistance through the safety injection piping; 2) changed the flow resistance in the safety injection lines, by an ECCS modification; and 3) analyzed appropriate pipe break accidents in accordance with 10 CFR 50 Appendix K criteria. The changes and results of tests and analysis were submitted to the NRC and were approved prior to restart of the plant after the refueling.[6-7]

DIESEL GENERATOR TRIP

During a loss-of-power test on August 26, 1977, the E-4 diesel of the Peach Bottom Atomic Power Station Unit 2 started properly as a result of the undervoltage condition, but tripped immediately. This trip was caused by the overspeed mechanism. The circuitry was reset, an adjustment was made to the mechanical governor to limit the diesel speed during a start and the unit was started successfully. Because the exact cause of the trip was not firmly established, surveillance testing of the diesel was increased from once a week to once per shift.

During one of these tests, on August 27, 1977, the diesel tripped again. Another adjustment was made to the mechanical governor, the load capability was checked and several successful starts were performed. Once per shift surveillance was continued.

On August 29, 1977, the diesel again tripped on overspeed and was declared inoperable. The diesel was then operated in excess of synchronous speed in order to determine the exact speed at which the overspeed mechanism would function. This test determined that the diesel would trip at 940 rpm instead of the desired setpoint of 990 rpm. The trip mechanism was adjusted to 985 rpm by a manufacturer's representative and diesel was started twice, successfully.

Investigation into the cause of the change in the trip setting determined that during the diesel maintenance in June 1977 a camshaft was replaced. In order to replace this camshaft the overspeed mechanism had been removed. When the overspeed mechanism was replaced, some necessary shims were not installed. Although this was the only diesel requiring this maintenance during the annual check, the other diesels were operated up to a speed of 945 rpm to verify proper operation. None of these diesels tripped on overspeed.

Analysis of this event revealed that a deficiency exists in the maintenance procedure associated with the diesel yearly inspection and the post-maintenance testing procedure. These procedures will be revised to correct the deficiencies.[8]

ELECTRICAL FAULT

On July 13, 1977 while the personnel at James A. Fitzpatrick nuclear power plant were conducting refueling operations a short in a cable caused 600 volts AC to be introduced into a 115 volt circuit. The 600 volt AC supply for the refueling bridge and the 115 volt AC circuit for refueling interlocks are both located in the same cable. Flexing of the cable with bridge motion over the core caused the cable to short internally. The introduction of the 600 volts into the 115 volt circuit caused nineteen relays in the rod manual control system to burn out. All of the refueling operations were halted until the interlocks were repaired. The rod worth minimizer and rod sequence control systems were also checked for damage.

A modification is being prepared that will remove the 115 volt AC interlock circuit from the cable carrying the 600 volt AC supply. This will prevent recurrence.[9]

PIPE CRACK

The Brunswick Steam Electric Plant Unit 2 was in hot shutdown and preparations were underway to startup the unit when the Shift Foreman noticed a small leak of the recirculation loop suction piping. This discovery was made during the closeout inspection of the drywell.

Investigation revealed the leak was from a crack in the socket weld on a three-quarter inch test connection 90° elbow that was nonisolable, and the plant was placed in the cold shutdown condition. The cracked pipe was cut out of the system and the connection was capped. Similar connections on both Units 1 and 2 were dye-penetrant checked with no other indications of cracks.

Further investigation revealed that the crack was contained in the weld metal and intergranular stress corrosion in the heat affected zone of the base metal was ruled out. A dye-penetrant inspection of the internal and external diameters of this section of pipe revealed no other cracks. The inspection of the internal diameter of the socket weld joints showed that a proper gap was present between the socket and the pipe end.

Based on a stress analysis and the observed condition of permanent deformation of the failed area, along with the location of the crack, it is concluded that the initial crack was caused by stress concentration in the weld fillet area. It is believed that this deformation was the result of workmen (during construction) using the pipe as a step. This use of the pipe for this purpose plus vibrational stress resulted in the failure.

A visual inspection of similar piping on the other loop of Unit 2 and both loops of Unit 1 revealed no deformation as was observed on the failed pipe. It was also noted that the location of the three remaining pipes is such that they are not likely to be used as a step or support because of physical interferences. These three pipes will be supported to protect them from experiencing excessive external loading and vibration, or will be removed and capped.[10-11]

Point of Contact:
Joseph I. McMillen
Office of Management Information
and Program Control
U.S. Nuclear Regulatory Commission

REFERENCES

1. LER 77-2, Docket No. 50-285, January 31, 1977.
2. LER 77-16, Docket No. 50-346, October 7, 1977.
3. Supplement to LER 77-16, Docket No. 50-346, November 14, 1977.
4. LER 77-23, Docket No. 50-344, July 29, 1977.
5. LER 77-21, Docket No. 50-219, September 23, 1977.
6. LER 77-30, Docket No. 50-29, August 3, 1977.
7. Summary of June 17 Meeting, NRC-YAEC, June 22, 1977.
8. LER 77-37A, Docket No. 50-277, September 9, 1977.
9. LER 77-43, Docket No. 50-333, August 11, 1977.
10. LER 77-7, Docket No. 50-324, February 28, 1977.
11. Supplement to LER 77-7, Docket No. 50-324, September 30, 1977.

Reference 11

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

DEC 1 6 1977

Those on Attached List

COMPUTER LISTINGS OF LICENSEE EVENT REPORTS SORTED BY FACILITY

The enclosed computer listing provides information concerning licensee event reports entered into the file during the month of November.

If you desire additional information or special searches, please do not hesitate to contact us.

T. A. Kirk, Acting Director
Regulatory Info. Systems Division
Office of Management Information
and Program Control

Enclosure:
As stated

DUPLICATE DOCUMENT

Entire document previously entered into system under:

ANO 7909240615

No. of pages:

Dupe of

7909240615

FACILITY/SYSTEM/COMPONENT/ COMPONENT SUBCODE/CAUSE CODE/ CAUSE SUBCODE/MANUFACTURER	DOCKET NO./ LER NO./ CONTROL NO.	EVENT DATE/ REPORT DATE/ REPORT TYPE	EVENT DESCRIPTION/ CAUSE DESCRIPTION
DAVIS-BESSE-1 COOLANT RECIRC SYS + CONTROLS PUMPS NO SUBCOMPONENT PROVIDED PERSONNEL ERROR CAUSE SUBCODE NOT PROVIDED ITEM NOT APPLICABLE	05000346 77 03L 019376	090177 100477 30-DAY	(NP-33-77-76) AT 1510 HRS ON 9/1/77, REACTOR COOLANT PUMP 1-2-1 TRIPPED DUE TO LOW SEAL INJECTION & COMPONENT COOLING WATER FLOW. IN ACTION STATEMENT OF T.S. 3.4.1, WHICH REQUIRES 4 RCPS IN MODE 1. REACTOR COOLANT PUMP 1-2-1 RE-STARTED AT 1524 HOURS ON 9/1/77. PERSONNEL ERROR. AN OPERATOR MISTAKENLY CLOSED VALVE IA 601 WHICH SUPPLIES INSTRUMENT AIR TO NORMAL MAKEUP FLOW CONTROL VALVE.
DAVIS-BESSE-1 COOLANT RECIRC SYS + CONTROLS VALVES NO SUBCOMPONENT PROVIDED DESIGN/FABRICATION ERROR CAUSE SUBCODE NOT PROVIDED ITEM NOT APPLICABLE	05000346 77 03L 019447	090777 100477 30-DAY	(NP-33-77-74) AT 0830 HRS ON 9/7/77, SWITCHING FROM NORMAL TO ALTERNATE POWER SUPPLY FOR DECAY HEAT SUCTION VALVE DH12, VALVE CLOSED. REACTOR OPERATOR IMMEDIATELY RE-OPENED VALVE & REESTABLISHED FLOW ABOVE 2800 GPM. DESIGN DEFICIENCY IN INTERLOCK/CONTROL CIRCUIT CAUSED THIS OCCURRENCE.
DAVIS-BESSE-1 REAC COOL CLEANUP SYS + CONT PUMPS NO SUBCOMPONENT PROVIDED DESIGN/FABRICATION ERROR CAUSE SUBCODE NOT PROVIDED BINGHAM PUMP CO	05000346 77 03L 019374	091777 101277 30-DAY	(NP-33-77-7[illegible]) AT 1800 HRS ON 9/17/77, MAKEUP PUMP 1-2 WAS REMOVED FROM SERVICE TO ALLOW MAINTENANCE TO REPAIR AN OIL LEAK ON OUTBOARD BEARING END PLATE. IN ACTION STATEMENT OF TECH SPEC 3.1.2.4, SINCE 2 MAKE UP PUMPS REQUIRED IN MODE 3. DESIGN DEFICIENCY. BUNA-N O-RING ON BEARING END PLATE DIDN'T FORM ADEQUATE SEAL AT BEARING HOUSING.
DAVIS-BESSE-1 OTHR INST SYS REQD FOR SAFETY INSTRUMENTATION + CONTROLS OTHER OTHER NOT APPLICABLE CONSOLIDATED CONTROLS CORP.	05000346 77-016/01T-0 019380	092477 100777 2-WEEK	HALF TRIP OF STEAM & FEEDWATER RUPTURE CONTROL SYSTEM CAUSED RISE IN REACTOR COOLANT SYSTEM TEMP & PRESSURE. CAUSED PRESSURIZER POWER RELIEF VALVE TO OPEN & VALVE FAILED TO CLOSE, CAUSING REDUCTION IN RCS PRESSURE. LCOS WERE EXCEEDED FOR 5 T.S., 3.4.1, 3.4.5, 3.4.6.2, 3.6.1.4 & 3.7.1.2 HALF TRIP CONDITION FROM SFRCS CHANNEL 2, WHICH CAUSED VALVE FWSP7A TO CLOSE. CAUSE OF THIS HALF TRIP HAS NOT BEEN POSITIVELY DETERMINED ALTHOUGH EXTENSIVE INVESTIGATION HAS REVEALED LOOSE CONNECTIONS AT TERMINAL BOARDS (POSSIBLE CAUSE).

Reference 12

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
799 ROOSEVELT ROAD
GLEN ELLYN, ILLINOIS 60137

NOV 22 1977

Docket No. 50-346

Toledo Edison Company
ATTN: Mr. James S. Grant
Vice President - Energy Supply
Edison Plaza
300 Madison Avenue
Toledo, OH 43652

Gentlemen:

This refers to the inspection conducted by Messrs. T. N. Tambling and T. L. Harpster of this office on September 26-30; October 5-7, 18-21, and 27, 1977, of activities at Davis-Besse Nuclear Power Station, Unit 1, authorized by NRC Operating License No. NPF-3 and to the discussion of our findings with Mr. T. Murray and members of your staff at the conclusion of the inspection.

The enclosed copy of our inspection report identifies areas examined during the inspection. Within these areas, the inspection consisted of a selective examination of procedures and representative records, observations, and interviews with personnel.

During this inspection, certain of your activities appeared to be in noncompliance with NRC requirements, as described in the enclosed Appendix A.

This notice is sent to you pursuant to the provisions of Section 2.201 of the NRC's "Rules of Practice," Part 2, Title 10, Code of Federal Regulations. Section 2.201 requires you to submit to this office within twenty days of your receipt of this notice a written statement or explanation in reply, including for each item of noncompliance: (1) corrective action taken and the results achieved; (2) corrective action to be taken to avoid further noncompliance; and (3) the date when full compliance will be achieved.

As discussed during the exit interview, it is requested that you submit a final followup report on the September 24, 1977 event. This report should include the chronology of events, pertinment transient data, evaluation of the transients and any long term effects, results of any testing and short and long term corrective action. This report will serve as a basis for a generic review of unusual transients.

Dupe of
8001170301

In accordance with Section 2.790 of the NRC's "Rules of Practice," Part 2, Title 10, Code of Federal Regulations, a copy of this letter, the enclosures, and your response to this letter will be placed in the NRC's Public Document Room, except as follows. If the enclosures contain information that you or your contractors believe to be proprietary, you must apply in writing to this office, within twenty days of your receipt of this letter, to withhold such information from public disclosure. The application must include a full statement of the reasons for which the information is considered proprietary, and should be prepared so that proprietary information identified in the application is contained in an enclosure to the application.

We will gladly discuss any questions you have concerning this inspection.

Sincerely,

Gaston Fiorelli, Chief
Reactor Operations and
Nuclear Support Branch

Enclosures:
1. Appendix A, Notice of Violation
2. IE Inspection Report No. 50-346/77-32

cc w/encl:
Central Files
Reproduction Unit NRC 20b
PDR
Local PDR
NSIC
TIC
U. Young Park, Power Siting Commission

OFFICE	RIII	RIII	RIII	RIII	RIII
SURNAME	Tambling/ls	~~Foepster~~ UK	Knop RCK	Little	Fiorelli RCK for
DATE	11/14/77				

Appendix A

NOTICE OF VIOLATION

Toledo Edison Company Docket No. 50-346

Based on the inspection conducted September 26-30, October 5-7, 18-21, and 27, 1977, it appears that certain of your activities were in noncompliance with NRC requirements below. The item is a deficiency.

Contrary to the approved Quality Assurance Manual and Criterion V of 10 CFR 50, Appendix B, Administrative Procedure 1823.00 was not completely adhered to in the logging and review of jumper - lift wires.

Dupe of
8001170306
1P

U.S. NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT

REGION III

Report No. 50-346/77-32

Docket No. 50-346 License No. NPF-3

Licensee: Toledo Edison Company
Edison Plaza
300 Madison Avenue
Toledo, OH 43652

Facility name: Davis-Besse Nuclear Power Station, Unit 1

Inspection at: Davis-Besse Site, Oak Harbor, OH

Inspection conducted: September 26-30, October 5-7, 18-21, and 27, 1977

Inspectors: T. N. Tambling 11/15/77

T. L. Harpster 11/18/77

Other Accompanying Personnel:
W. Little, September 30, 1977
L. Engle, September 30, 1977
V. Leung, September 30, 1977
A. Szuklewicz, September 30, 1977
J. Mazetis, September 30, 1977
J. Rajan, September 30, 1977
J. Pittman, October 19-20, 1977
A. Plumber, October 19-20, 1977
R. Denning, October 19, 1977

Approved by: R. C. Knop, Chief 11/21/77
Reactor Projects Section 1

Dupe of
8001170344

19 pp

Inspection Summary

Inspection on September 26-30, October 5-7, 18-21, and 27, 1977 (Report No. 50-346/77-32)

Areas Inspected: Investigated the causes, evaluation and corrective action associated with the sudden depressurization of the reactor coolant system on September 24, 1977, routine, unannounced inspection of plant operation, tour of plant areas, followup of modification to electrical grid system to meet licensee commitment, and nonroutine event reports. The inspection involved 110 inspector-hours onsite by two NRC inspectors.

Results: Of the four areas inspected, no items of noncompliance or deviations were found in three areas; one apparent item of noncompliance and two unresolved items were found in one area (deficiency - failure to properly implement procedure for jumper-lifted wire - Paragraph 6.b, and unresolved - open water tight door, - Paragraph 7 - apparent defect in a cable penetration seal, Paragraph 7).

DETAILS

1. Persons Contacted

J. Evans, Station Superintendent
*T. Murray, Assistant Station Superintendent
*L. Stalter, Technical Engineer
*W. Green, Administrative Coordinator
*J. Buck, Operations QA Manager
*W. Derivan, Acting Operations Engineer
L. Grime, Reliability Engineer
D. Briden, Chemistry and Health Physicist
F. Faist, B&W Site Operations Manager

*Denotes those attending the exit interview.

The inspector also talked with and interviewed other licensee employees including members of the technical and engineering staffs, reactor shift crews, and startup test leaders. The inspector also participated in a meeting on September 30, 1977 at Davis-Besse that included representatives of NRR, TECo Engineering, TECo Corporate Management, Babcox-Wilcox Company and Bechtel Corporation.

2. Licensee Action on Previous Inspection Findings

(Closed) Noncompliance (50-346/77-16): Failure to properly document a review of a reportable occurrence and proper adherence to the administrative procedures for processing deviation reports. The inspector found that Administrative Procedure AD 1807.00 was revised to clarify the apparent awkwardness in the procedure and that the procedure is being implemented to insure required review of reportable and nonreportable occurrences tracked by the deviation report system. (Paragraph 6.a)

3. Loss of Steam Generator Feedwater Supply and Depressurization of Reactor Coolant System 1/

On September 25, 1977, the licensee reported to Region III that a spurious trip signal in the Steam Feedwater Rupture Control System (SFRCS) on September 24, 1977 initiated a series of events that resulted in the loss of feedwater supply to the No. 2 Steam Generator, depressurization of the Reactor Coolant System (RCS) and

1/ Licensee submitted 14 day Licensee Event Report NP-32-77-16 on October 7, 1977.

rupture of the rupture disc on the pressurizer quench tank that resulted in damage to the mirror insulation on the No. 2 steam generator. An NRC Region III inspector was dispatched to the site September 26, 1977 to investigate the results of the incident, the action being taken by the licensee and corrective action planned.

Based upon the inspectors review and upon telephone conversations between Region III and representatives of Toledo Edison Company, an immediate action letter was issued to the licensee on September 30, 1977. This letter designated the corrective action required before the reactor could be returned to operation.

In the initial review of the incident, the inspector reviewed current status of the plant, proposed corrective action, details of the event, its safety significance, operation of engineered safety features during the event, conformance of the limiting conditions of operations, possible generic aspects, and possible radioactive releases or contaminations.

In followup, the inspectors reviewed the licensee evaluations of the incident, the results of testing and completed and/or planned corrective action.

The findings are as follows:

a. Transient Chronology

Initial Conditions

The reactor was at the 15% plateau in the startup test program and had accumulated approximately one effective full power day (EFPD) history. A high pressure turbine pressure tap between the turbine and the governor valve was found to be cracked. Power was reduced to approximately 9% and the turbine was shutdown to repair the leak. Main feed pump turbine 1-2 was receiving steam from steam generator (OTSG) No. 2, and feeding both OTSG's through their respective startup feed control valves.

Sequence of Events

21:34:20 - A spurious half trip actuated the Steam-Feedwater Rupture Control System (SFRCS). The half trip closed the startup feed control valve to OTSG No. 2. The operator has only valve position demand signal indication and thus was unaware of the feed isolation. Other valves that would move on the half trip were already in the tripped position and thus gave no alarm. The alarms received by the operator were main steam lines 1 and 2 isolation valve (MSIV) solenoid trouble alarms which alarm only on the computer. (This was a partial arming of the control circuit that actuates the MSIV to close on a full SFRCS trip).

21:34:44 - Low level alarm OTSG No. 2. (Setpoint 24" startup range). MFP turbine 1-2 is still steaming off the generator but the feed is isolated causing the level to decrease rapidly.

21:34:56 - High temperature alarm loop 2. (Setpoint 560.6° F wide range cold leg). Decreasing OTSG No. 2 level reduces heat transfer capability.

21:35:16 - High pressurizer level alarm. (Setpoint 220"). Coolant is expanding into pressurizer from increasing loop temperature.

21:35:18 - OTSG No. 2 low level trip alarm. (Setpoint 17" startup range). This signal combined with the spurious half trip completes the logic for a full SFRCS trip. The full trip closed the MSIV's and lined up both OTSG's to the auxiliary feed system.

21:35:26-:49 - A reconstruction of data indicates that the pressurizer power relief valve actuated and cycled nine times before failing in the open position. The relief valve cycled about the setpoint (2255 psig) because a close relay which provides a 50 psi deadband was physically missing from the system. The rapid cycling apparently caused some deformation of the pilot valve stem. However, pilot valve failed open due to galling of the stem. This resulted in the electromatic relief valve failing open and led to a continued depressurization of the reactor coolant system (RCS).

21:35:36-:38 - AFPT's 1 and 2 discharge valves were open. AFPT 2 only came up to 2600 RPM (normal is 3600 RPM) because of binding in the woodward governor linkage. This corresponds to a shutoff head of approximately 700 psid. Thus, no water was fed into OTSG No. 2 as this pressure was considerably below OTSG No. 2 steam pressure until 11 to 15 minutes into the transient.

21:35:55 - Pressurizer power relief temperature high. (Setpoint 200^{o}F). Control room indication that relief valve had opened.

21:36:04 - AFP's 1 and 2 discharge valves open and water is being fed into OTSG No. 1.

21:36:07 - The operator manually tripped the reactor because pressurizer level was approximately 300" and rising. About two seconds after the trip, level reached 303" and started decreasing. Loop 2 hot leg temperature reached a maximum of approximately 584^{o}F six seconds after the trip and started decreasing. Loop 2 cold leg temperature reached a maximum of approximately 579^{o}F 14 seconds after the trip. RCS pressure continued to blow down and various Reactor Protection System (RPS) trips occurred from low pressure as designed.

21:37:17 - The Safety Features Actuation System (SFAS), incident level 1 initiated at 1600 psi. The pressurizer quench tank vent isolation valves closed on containment isolation due to SFAS actuation.

21:37:49 - At this time it was noted that HPI flow indicator FYIHP3A was not indicating flow into the RCS, however, it was later determined that the initial flow was blocked by two higher head makeup pumps injecting 140 GPM through this line.

21:40:22 - The containment normal sump pump came on indicating the quench tank rupture disc had blown. HPI pumps were shutdown at this time as pressurizer level was normal.

21:41:50 - Saturation pressure was reached in the reactor coolant system. Steam formation was probably occurring in the Reactor Coolant Pump (RCP) suctions.

21:43:41 - RCP's 1-1 and 2-2 were tripped. At this time the transient was essentially terminated with the exception of the subsequent recovery actions. The block valve for the failed electromatic pressurizer relief valve was closed approximately 20 minutes after the start of the incident.

b. Analysis of the Failures and Corrective Action

(1) SFRCS Half Trip

The half trip logic in the SFRCS is used on certain valves in the steam and feedwater systems to meet the single failure criteria for isolation of the atmospheric steam line power vent, the MSIV bypass, main steam warmup drain and startup feed control valves. A one of four input will close these valves. (It should be noted that all except the main steam atmospheric power vent valve are normally in the closed position when operating above 15% power). A two of four logic is used on other valves in the Steam-Feedwater System.

Failure to see this spurious trip that initiated the incident was due to two reasons. The logic circuit requires only a signal duration of 25-35 milliseconds to lock in. The computer which is used to show the alarm condition is scanning at a one second interval. Therefore, trip signals of less than one second may not be seen on the computer. Other visual or alarm indications (such as annunicators) were not available in the control room.

Corrective action by the licensee was divided into two phases to rectify this problem. The first and immediate action was to connect six channel Brush Recorders on SFRCS input channels to provide detection of short term spurious signals. Followup action involves the installation of annunicator windows for half trips on steam generator low level, loss of reactor coolant pumps and steam-feedwater delta pressure. An annunicator presently exists on low steamline pressure. A feasibility study will be made to determine whether a time delay circuit can be used on the trip signal to make sure that the computer will also see short term signals (i.e. less than one second)

(2) Auxiliary Feedwater Pump

On a full SFRCS trip the two auxiliary feedwater pumps (AFP) are aligned and started to feed the two steam generators. The alignment is one AFP to one steam generator except for the main steamline break accident. For the steamline break (detected by low steamline pressure) the AFP to the affected steam generator is aligned to receive steam and feed the unaffected steam generator (the one without the line break).

When the spurious half trip isolated feedwater flow to No. 2 steam generator, a full SFRCS trip was initiated on low steam generator level (see Transient Chronology). The AFP's were properly aligned and started. However, No. 2 AFP only reached approximately 2600 rpm (vs desired 3600 rpm) due to a binding in the Woodward governor on the Terry Turbine driving the AFP. At 2600 rpm the maximum pump discharge pressure is approximately 700 psig. This head was not adequate to provide feedwater to the No. 2 steam generator until pressure in the steam generator decreased to this pressure (approximately 11 to 15 minutes into the event).

The loss of one steam generator for a controlled cooldown of the reactor is within the accident analysis which assumes only one steam generator available. However, the failure of the governor on the AFP turbine presents a generic or common mode failure problem. (This was reported by the licensee in a letter from L. E. Roe to J. G. Keppler dated October 11, 1977 in accordance with 10 CFR, Part 21.21(b)).

The licensee through the manufacturer analyzed the failure mechanism of the governor. It was concluded that under certain conditions the servomotor control driving the turbine speed control against the high speed stop places a misalignment force on the T-bar of the governor linkage. This misalignment force creates a potential for the governor to bind at a speed position less than design speed upon turbine startup. The governors for both AFP's were modified to correct this problem.

The failure of the No. 2 AFP to come up to speed and feed the No. 2 steam generator also resulted in the steam generator "boiling dry." This was concluded based upon the rapid rate of pressure decay inside the steam generator. Although this condition is not desirable, the incident is within the design analysis for the steam generator as supplied by the manufacturer. The analysis placed a 20 cycle limitation on the generator over its lifetime. The licensee has an administrative system for tracking operational transients over the lifetime of the plant to insure cycle limitations are not exceeded.

(3) Reactor Coolant System Depressurization

The transient on the secondary side caused a corresponding operational transient in the Reactor Coolant System (RCS). This transient, while not desirable, would normally be within the design capability of the syten without damage to equipment. However, due to the failure of the electromatic relief valve on the pressurizer, to properly reset after relieving there was damage to the mirror insulations on the No. 2 steam generator, minor damage to a ventilating duct and spillage of reactor coolant inside the containment vessel.

The licensee's investigation into the failure of the electromatic relief valve revealed that the close relay was missing from its control circuit. The missing relay caused the relief valve to cycle around its set point of 2255 psig until the pilot valve steam stuck in the open position. This failure of the pilot valve caused the relief valve to remain open continuously relieving the pressurizer to the Quench Tank. The relief valve remained until approximately 20 minutes into the event when the operator closed the block valve to the relief valve. Lack of earlier recognition that the relief valve had failed open was due to the fact that the operator did not have positive indications of the valve position on the control board. To correct this problem, the licensee installed a position light on the control board to indicate the position of the pilot valve solenoid. (Usual indications that the relief valve opens initially is by a temperature monitor in the valve line).

The licensee's inspection of the pilot valve revealed that the stem stuck in the open position due to galling.

There is no explanation as to why the reset relay was missing from the control circuit. A review of the preoperational test procedure performed prior to and during hot functional testing shows that the electromatic valve functioned properly. Prior to the preoperational test, the licensee performed a yellow line (circuit checkout) of the control scheme. Both of these items indicate that the control relay had been in the circuit. It should be noted that the electromatic relief valve control circuits are not classified safety related and therefore do not fall within the normal quality control purview.

After inspection of the relief valve and replacement of the pilot valve, the licensee tested the valve by manually cycling the valve six times with the RCS at approximately 600 psig. The pilot valve stuck in the open position again after the sixth cycle.

Inspection of the pilot valve stem revealed some scratches on the stem and that the outside diameter of the stem was .0005 inches oversize. (Normal annulus clearance is .001 inches). At the recommendation of the valve manufacturer, the stroke of the solenoid for the pilot valve was reduced from 3/8 inches to 1/8 inches. This change in stroke still allows the pilot to function as designed and considerably reduces the stem surface area exposed to the steam, dirt, boric acid, etc. when the valve operates.

Reduction in surface area exposed to the steam flow prevents possible accumulation of contaminates on the bearing surface of the stem.

After the correction to the stroke travel and stem diameter, the electromatic relief valve was retested. The valve was manually cycled ten times at approximately 600 psig RCS pressure and once at approximately 2200 psig. The valve functioned as designed.

The RCS components are designed for forty cycles of a generalized depressurization transient in which the pressure drops 1400 psi and the temperature drops $62^{\circ}F$ in fifteen minutes. In the actual transient on the RCS side, the pressure dropped approximately

1300 psi in eight minutes and the cold and hot leg temperature in loop 2 dropped approximately 41.5 and 45°F respectively in 7.5 minutes.

An analysis of the transient was performed by B&W for the licensee. Based upon this analysis, B&W concluded that this transient was within the scope of the generalized depressurization transient previously analyzed.

(4) Reactor Coolant Pumps

Because the Reactor Coolant pumps (RCP) operated at or near the saturation pressure during portions of the transient, there was some concern of possible damage to pump shaft seal bearings and impellers. The operating condition was reviewed by the pump manufacturer. The manufacturer concluded that there was small risk of any damage. To provide assurance, the licensee performed instrumented tests in Mode 5 and 3 to verify normal operating parameters.

(5) Reactor Fuel

B&W also evaluated the possible effects on fuel performance as a result of the transient and concluded that there were no safety concerns with respect to the reactor fuel. This conclusion was based upon:

- Core burnup on September 24 was approximately 1 EFPD (no significant fission product inventory).

- Because of the low operating power history (15% and less) there was no significant decay heat source as compared to the source from the RCP's.

- Conservative estimate that the maximum ΔP between the internal fuel rod pressure and RCS pressure was 300 psi and a maximum clad temperature of 550°F at this ΔP.

(6) Containment Contamination from RCS

The spillage of RCS water did not constitute an airborne release problem inside containment. This was due in part because of the short operating history of the fuel assemblies. No detectable fission gases were present in the RCS. There was low level contaminates due to normal activation products in the RCS (activation of normal corrosion products). This contamination was controlled and cleaned up by the licensee using standard radiation control procedures.

(7) Training and Retraining

To insure that operating personnel understood the sequence of events, the licensee conducted retraining on the SFRCS. This training involved two four hour sessions. The first session involved a description and analysis of the event. The second session covered a detailed description of SFRCS. The training of the various shift teams plus other personnel was completed October 22, 1977.

4. Second Loss of Feedwater Transient

On October 22, 1977, a spurious half trip from SFRCS closed the startup feedwater valve to the steam generator. During this transient, all plant operating equipment performed as designed. Both AFP's started and reached 3600 rpm. The pressurizer electromatic relief valve actuated twice and reset as designed.

Although the 6 channel Brush recorders installed to record the source of the spurious signal did not record the event, the licensee was able by a process of elimination to isolate the possible sources. Two buffer amplifiers and three integrated circuit clips were replaced as probable causes for the spurious signal. The licensee is continuing his efforts to positively identify the source of spurious signal.

5. Electrical Grid Stability Modification

Per Condition 2.C.(3)(q) of Operating License NPF-3, the licensee submitted an evaluation and proposed modifications to electrical grid protective system to NRR for review. The purpose of these modifications is to insure adequate breaker coordination, alarm and isolation of the onsite electrical system in sufficient time to permit the required Class 1E equipment to operate in the event of offsite grid degradation.

The inspector reviewed and examined the implementation of the subject modification as designated by the licensee's letter of July 18, 1977 (Serial No. 293) to J. E. Stoltz from L. E. Roe and Facility Change Request 77-217 (original and supplement No. 1). No deficiencies were identified by this review.

The review effort included review and examination of procurement records, certification for Class 1E equipment, work orders used for installation, setpoint changes and setting, safety review, SRB review of the facility change and procedures used, and discussions with members of the engineering staff and operating staff involved in the design and installation of the modifications.

6. Plant Operations - General

The inspector reviewed general plant operations including an examination of selected operating logs, jumper-lift wire logs, deviation reports for the period of July 1977 through October, 1977. This review was made to determine compliance with technical specifications and administrative procedure requirements.

a. Deviation Reports

While reviewing the deviation reports, the inspector noted that 38 reports (for the period July 11, 1977 to August 16, 1977) had not been filed in the master file. Seven of these were on the SRB agenda for final review and closeout. The others were still outstanding for final resolution. It was noted that although copies of these reports were not in the master file, the reports are logged and are being tracked by the technical section. For the reports found in the master file, many still remain open and require final closeout.

In response to a previous item of noncompliance (Inspection Report 77-16), the licensee initially revised Administrative Procedure AD 1807.00 on July 12, 1977 and approved it for implementation on September 9, 1977 to improve and clarify the review process for deviation reports. It was noted there has been an apparent improvement in the tracking and review of DVR's issued since the procedure revision.

However, even though the DVR's are used by the licensee as a control document that does not get closed out until all corrective action is completed (including corrective action covered by facility change request or action item record), there appears to be a large number of open DVR's in the files. Many of these can and should be closed in a more orderly matter. This need to reduce the large backlog of open DVR's was discussed with the licensee during an exit interview.

b. Jumpers and Lift Wire Log

The inspector reviewed the jumper and lift wire log and the implementation of Administrative Procedure AD 1823.00, Jumper and Lift Wire Control. From a previous inspection, (Inspection Report 77-16), it had been noted that a large number of jumper and lift wire tags were outstanding. The status of the licensee's effort to reevaluate the need of these jumpers and lift wires was reviewed. Considerable progress had been made and the effort is still in progress as noted by the internal review presently being conducted by the operations section.

The inspector selected several jumper-lift wire - tags numbers at random and verified that they do exist.

The need to expedite this effort was discussed in the exit interview.

AD 1823.00 jumper-lift wire log sheets requires the persons placing the tag to reference the work order request number and the reason for the tag on the log sheets. A review of the log sheets indicated that this was not being consistently done. Examples were:

- Tag No. 4073 through 4084, no reason was given for tags.
- Tag No. 4163 through 4166, no work order number was referenced.
- Tag No. 4123 through 4126, no reason was given for tags.

In the exit interview the inspector discussed how failure to provide this information is considered an inadequate review by the tagging supervisor (DBTS), the Shift Foreman who is suppose to review the current status each shift and the Operations Engineer (or his representative) monthly review. This failure to properly implement AD 1823.00 is considered an item of noncompliance.

Also discussed in the exit interview was a possible inconsistency in how individual DBTS handled critical tags (tags with safety implications). The current procedure does not require documentation to show how and what the DBTS considered in the placement of critical tags.

7. Plant Tour

The inspector toured various areas of the plant to observe operations and activities in progress. This included general state of housekeeping, proper alignment of valves in the high pressure injection of SFAS, status of EVS boundary, leaks, pipe vibrations, radiation controls, shift manning, discussion with operating personnel concerning lighted annunciators, and review of a startup procedure currently being implemented.

No items of noncompliance were specifically identified. However, two items were left unresolved and there was one item of major concern.

As discussed in an exit interview, the plant is currently operating with a large number of lighted annunciators. The inspector stated that there appears to be a need for the licensee to review the current status of lighted annunciators for the purpose of eliminating nuisance alarms, alarms that apparently have logic problems or in which the setpoint span may be too tight. Examples are:

- Panel 1, window 2-8, Emerg D/G FOS T 1/2, Hi/Low. If tank is overfilled, light is lit (alarmed condition). The operators concern is low level since he has no other means to determine what the level is. A sudden change in the status of tank could go undetected (from Hi alarm to Low alarm).

- Panel 1, window 1-5 and 1-6, ESSEN Bus E-1 and F-1, Breaker not normal. Window always lit because there is no normal position.

- Panel 5, windows 5-1, SFAS CTMT Rad Low- ail. Window remains always lit because of detector location. There is not sufficient background radiation to make the meter read above zero.

On October 27, 1977, at approximately 1500 hours, the water tight door separating the two auxiliary feedwater pumps was found open during a tour. The door was immediately closed. This item is unresolved pending further investigation.

On October 27, 1977, a black oily material was found dripping from a ceiling cable penetration in the cable spreading room. This item is unresolved pending further investigation by the licensee.

8. Onsite Review of Inspection Process

The inspector was accompanied by two people from Battelle-Columbus and one person from the Office of Nuclear Regulatory Research on October 19 and 20, 1977. Battelle is currently under contract to the NRC to evaluate methods for applying WASH-1400 methodologies to the inspection process. Observations were made of the current inspection process.

9. Review of Nonroutine Events Reported by the Licensee

The inspector reviewed licensee actions with respect to the following listed nonroutine events reports to verify that the events were reviewed and evaluated by the licensee as required by Technical Specifications, that corrective action was taken by the licensee, and that safety limits, limiting safety system settings, and limiting conditions for operation were not exceeded. The inspector examined selected Operations Committee minutes, licensee investigation reports, logs, and records, and inspected equipment and interviewed selected personnel.

Two inoperable relative position indicators in Group 6 of CRD System (NP-32-77-15).

Loss of Reactor Coolant pressure due to failure of pressurizer power operated relief valve (NP-32-77-16). (See Paragraph 3 for details)

No items of noncompliance or deviations were identified.

The following licensee event reports were reviewed and closed out on the basis of an in-office review and evaluation:

a. Hydro test on High Pressure Injection line (NP-33-77-28).

b. Steam generator level limit exceeded (NP-33-77-30).

c. Chlorine detector AE 5358A inoperable (NP-33-77-31).

d. Loss of Shield Building integrity for H_2 Purge System 18 month test (NP-33-77-33).

e. Planned replacement of overload heaters in Control Room Emergency Vent condensing unit (NP-33-77-37).

f. Loss of DC power to speed control switches for SS 815 and SS 816 for testing (NP-33-77-39).

g. Removal of Auxiliary Feedwater pump 1-2 from service to implement wiring change (NP-33-77-41).

h. Main steam supply line check valve bonnet leak (NP-33-77-42).

i. Loss of shield building integrity due to unlatched door (NP-33-77-47).

j. Containment normal sump total flow instrument string inoperable (NP-33-77-49).

k. AFP turbine 1-2 inoperable due to loss of speed control (NP-33-77-51).

l. AFP turbine 1-1 inoperable due to loss of speed control (NP-33-77-52).

m. AFP 1-2 inoperable due to ground in speed control switch (NP-33-77-53).

n. Flow path from boric acid storage system operable (NP-33-77-54).

o. Main steam isolation valve M 5100 failed closed due to loss of control air (NP-33-77-55).

p. NI-3 inoperable to connect to reactimeter (NP-33-77-59).

q. API for control rod 4 of group 4 inoperable (NP-33-77-63).

r. DH pump 1-2 made inoperable to install union in cooling water line (NP-33-77-66).

s. Channel 3 of RPS inoperable (NP-33-77-67).

t. Hydraulic snubber HBD-19-H144 inoperable (NP-33-77-69).

u. Main steam line hydraulic snubber SR 17 and SR 11 inoperable (NP-33-77-70).

v. AFP 1-1 steam supply isolated for maintenance (NP-33-77-71).

w. Reactor coolant system T avg less than 525°F (NP-33-77-75).

10. Unresolved Item

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, items of noncompliance, or deviations. Two unresolved items disclosed during the inspection are discussed in Paragraph 7.

11. Exit Interview

The inspectors met with licensee representatives (denoted in Paragraph 1) on October 7, 21 and briefly on October 27, 1977 to summarize the findings of the inspection. The licensee representatives made the following remarks in response to certain of the items discussed by the inspector.

October 7, 1977

Stated that in addition to the corrective action taken to date on the September 24, 1977 incident they would (Paragraph 3):

a. Instrument SFRCS inputs to help detect spurious signals.

b. Add SFRCS annunciator windows.

c. Study the feasibility of a time delay mechanism so that the computer can log short term spurious signals.

d. Complete training on the SFRCS by October 22, 1977.

e. Test the modified AFP turbine governors in place in Mode 3.

f. Test the electromatic pressurizer relief valve cold and hot (at approximately 600 psig). During a telecon on October 14, 1977, when the relief valve failed on the sixth hot cycle test, the licensee stated that they would retest the valve ten times at 600 psig and once at approximately 2200 psig.

g. Complete the testing of the reactor coolant pumps at a pressure equal to or above 1300 psig.

Acknowledge that the return to power operation was predicated upon the successfull completion of the above tests. Also stated that they would keep the inspector informed of the progress of the testing.

Acknowledge the inspectors request for a detailed followup report on the September 24, 1977 incident including a detailed analysis of the long term effect of the transients.

<u>October 21, 1977</u>

Acknowledge the inspectors concern about the jumper-lift wire logs and acknowledged the inspectors statement with respect to the apparent item of noncompliance (Paragraph 6.b.).

Acknowledge the inspectors concern about the status of control room annunciators and stated that they have been pursuing the problem. (Paragraph 7)

Acknowledge the inspectors statements about the number of outstanding deviation reports. (Paragraph 6.a.)

<u>October 27, 1977</u>

Acknowledge the inspectors review of the modification of the electrical grid system. (Paragraph 5)

Acknowledge the inspectors findings concerning the open water tight door and stated that they would check their procedures to determine why the door was left open. (Paragraph 7)

Acknowledge the inspectors findings concerning the black oily material dripping from a penetration in the cable spreading room and that they would immediately investigate and determine the extent of the problem. Informed the inspector on October 28, via telephone that the problem appeared to be confined to the one penetration and that they were pursuing it further with both Dow Chemical Company and BISCO. (Paragraph 7)

TOLEDO
EDISON

JAMES S. GRANT
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Docket No. 50-346

December 14, 1977

Serial No. 1-6

Mr. Gaston Fiorelli, Chief
Reactor Operations Branch, Region III
U. S. Nuclear Regulatory Commission
799 Roosevelt Road
Glen Ellyn, Illinois 60137

Dear Mr. Fiorelli:

Toledo Edison acknowledges receipt of your November 22, 1977, letter and report enclosure 77-32 referencing an apparent deviation from Davis-Besse Nuclear Power Station Unit No. 1 commitments to the NRC, listed as a "Deficiency" under the heading "Notice of Violations".

Following a thorough examination of the item of concern, Toledo Edison herein offers information regarding this item, including corrective actions and the dates of corrective actions.

Item b Deficiency: Contrary to the approved Quality Assurance Manual and Criterion V of 10CFR50 Appendix B, Administrative Procedure AD 1823.00 was not completely adhered to in the logging and review of jumper-lift wires.

Response: The corrective action taken and the results achieved and the corrective action taken to avoid further non-compliance are as follows:

1. Administrative Procedure AD 1823.00, Jumper and Lifted Wire Control, was revised November 10, 1977, to insure the jumper and lifted wire log sheets are filled out consistently.

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2. The Davis-Besse Tagging Supervisors (DBTS) have been informed of the importance of filling out the jumper and lifted wire log sheets correctly and consistently.

Full compliance will be achieved when all of the outstanding jumper and lifted wire log sheets are updated, which will be accomplished by December 20, 1977.

Very truly yours,

J. S. Grant

JSG/WHG/daw