U.S. NUCLEAR REGULATORY COMMISSION

REGION III

AUGMENTED INSPECTION TEAM

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Licensee:	Commonwealth Edison Company
Facility:	Dresden Nuclear Station Unit 3
Location:	Opus West III 1400 Opus Place - Suite 300 Downers Grove, IL 60515
Dates:	May 16 through May 23, 1996
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EXECUTIVE SUMMARY

On May 15, 1996, the failure of a Unit 3 feedwater regulating valve (FRV) resulted in a complete loss of feedwater to the reactor. The reactor automatically tripped and emergency systems, such as the high pressure coolant injection (HPCI) and Group 1 primary containment isolation, actuated as designed. Following the initial transient, control room operators reset the Group 1 isolation signal in order to restore the main condenser as an alternate heat sink. When the Group 1 isolation signal was reset, an inboard main steam isolation valve (MSIV) and a recirculation sample isolation valve (220-45), unexpectedly opened due to a failed relay in each of the valves' control circuits. The operators manually reclosed the valves and reverified the other Group 1 primary containment isolation system (PCIS) valves had remained closed.

After the two Group 1 isolation valves unexpectedly opened, an Unusual Event was declared and the emergency plan was activated due to the potential degradation in the level of plant safety. The plant was cooled down using the isolation condenser and the shutdown cooling system. The Unusual Event was terminated after the plant was in Cold Shutdown and reactor coolant chemistry samples verified fuel integrity.

The AIT concluded that the control room operators performed the appropriate immediate actions, stabilized reactor water level and pressure, and placed the plant in a shutdown condition in accordance with plant procedures. Observations of control room activities during the event noted that operators monitored control room indications, supervisors maintained proper command and control, and 3-way communications were used.

The licensee formed a "Task Force" to review the event, to identify the root causes of the equipment malfunctions (FRV and the Group 1 relays), and to develop immediate and long term corrective actions for the failures. The Task Force initially appeared to be narrowly focused on repairing the failed equipment and correcting specific causes for the failures. Additionally, some members of the Task Force were initially involved with both the repair efforts and the root cause investigation. However, licensee management recognized that a larger team with broad and distinct responsibilities was needed and subsequently assigned additional resources to the Task Force.

The failure mechanism for the loss of feedwater transient was determined to be a stem to disk separation of the in-service feedwater regulating valve (FRV 3B) due to high-cycle, low-stress fatigue cracking due to flow induced vibration. The primary root cause was the flow induced vibrations which may not have been accounted for in the design of the stem.

The unexpected opening of the main steam isolation valve and the reactor recirculation sample isolation valve resulted from a failed relay in each of the valves' seal-in logic control circuit. The relays were mechanically bound due to an interference fit of the phenolic block at the armature support bracket pivot points. The dimensional variations could have occurred during the manufacturing process.

The licensee's engineering root cause determination teams were effective in investigating and identifying the technical problems related to the feedwater valve failure and the PCIS control relay failures. The licensee provided sufficient engineering resources and developed a multi-discipline team consisting of site and corporate engineering and technical specialists. Assembly and disassembly of the feedwater valve were well controlled and new information was methodically evaluated. Assumptions made by the feedwater valve failure investigative team were challenged and verified to be reasonable. In addition, a final independent review of the feedwater valve failure and the proposed corrective action was performed by two technical design engineering consultants. Throughout the PCIS relay testing process, an approved test plan was used and the instructions were written in a logical manner that preserved the as-found condition of the relays. The inspectors concluded that the failure mechanisms and the root causes were methodically determined and were technically founded.

Overall, the inspector's concluded the licensee's investigation was self critical and intensive. The root cause determinations were reasonable and technically sound. The systematic approach and depth of the investigation assured appropriate corrective actions were developed.

However, the inspectors also concluded that the engineering modification backlog contributed to the delays in completing planned modifications to the 3B FRV. In addition, the inspectors concluded the station's maintenance backlog contributed to the delays in repairing the isolated 3A FRV and in the missed opportunities to identify a generic trend in the failed PCIS control relays in 1994 and 1995.

The licensee's decision to isolate the 3A FRV two weeks prior to the event focused primarily on the existing steam leak and personnel protection and less on the relationship of the FRV to the reactor. The licensee placed the plant in a configuration that required ECCS initiation following the failure of the 3B FRV. The inspectors concluded that the decision to operate on a single FRV for an extended period of time was non-conservative and resulted from unresolved material condition issues.

REPORT DETAILS

1.0 Purpose of the Augmented Team Inspection

Following initial review of the May 15, 1996, loss of feedwater transient to the Dresden Unit 3 (U-3) reactor, the NRC formed an Augmented Inspection Team (AIT) to examine the circumstances surrounding the event. The AIT Charter included evaluations of plant equipment performance, operator response to the event, the effectiveness of the licensee's root cause investigation, and the effectiveness of the corrective actions. The AIT Charter is included as Attachment 1 to this report.

2.0 Event Description [Charter Item No. 1]

The Event Description and Sequence of Events were independently developed and validated by the inspectors using the following information:

- Review and evaluation of control room instrument chart recorders; plant alarm and data print outs; and log books from the nuclear station operators (NSO), unit supervisors (US), and shift manager.
- Interviews with personnel directly involved in the event.
- Observations by onsite NRC inspectors at the time of event occurrence.
- Review of the licensee's investigation and time line.

On May 15, 1996, at 10:43 a.m. (CDT), a valve failure (the plug separated from the stem) on the U-3 3B feedwater regulating valve (FRV) resulted in a complete loss of feedwater to the reactor. The subsequent automatic reactor trip and emergency core cooling systems (ECCS) actuation occurred as designed. (See Section 3.1 for the root cause of the FRV failure.) Prior to the event, U-3 was operating at 82 percent of full power (677 megawatts electrical (MWe)) and had been on-line since November 11, 1995. Normal offsite power and all emergency equipment were operable. Routine surveillance testing on the U-3 containment cooling service water (CCSW) system was in progress. The 3A FRV and the associated inlet isolation valve (MO-3206A) had been closed since April 27, 1996, due to a body-to-bonnet leak on the 3A FRV. The 3B FRV was controlling reactor water level in single element control at the normal operating level (about +30 inches (in.)).

After the 3B FRV failed, all feedwater flow to the reactor was blocked and water level rapidly dropped to the automatic low level scram setpoint (+17 in.). All control rods fully inserted and all other equipment and isolation signals operated as designed. Reactor water level continued to decrease until the Low-Low water level setpoint was reached (-51 in.). At this point, the high pressure coolant injection (HPCI) system started, main steam isolation valves (MSIV) closed (Group 1), and other safety equipment automatically functioned as designed.

Reactor water level continued to decrease until the HPCI and the control rod drive (CRD) systems began to restore vessel level. The lowest level reached was about -59 in., which was 84 in. above the top of active fuel. As water level increased, control room operators reduced HPCI flow to control vessel water level and reactor pressure. The isolation condenser was manually placed in service to control reactor pressure and to commence a plant cooldown.

At 11:11 a.m., the Groups 1, 2, and 3 isolation signals were reset in order to restore the main condenser as an alternate heat sink (if needed) and the reactor water cleanup (RWCU) system for level control. When the signal was reset, the 1A MSIV (inboard) and the 220-45 recirculation sample isolation valve, both Group 1 valves, unexpectedly reopened. The cause for the valves to reopen was later determined to be failed relays in the valves' control circuits. The operators manually reclosed the two valves and reverified the other Groups 1, 2, and 3 isolation valves were closed. (See Section 4.1 for additional information on the relay failures.)

After the two Group 1 isolation valves unexpectedly reopened, the licensee declared an Unusual Event (11:22 a.m.) and activated the emergency plan due to the potential degradation in the level of plant safety. All notifications were performed as required. The licensee continued the plant cooldown using the isolation condenser and the shutdown cooling (SDC) system. The Unusual Event was terminated at 11:08 p.m. after the plant was in Cold Shutdown and reactor coolant chemistry samples verified fuel integrity.

A detailed Sequence of Events is included as Attachment 2 to this report.

3.0 Failure of 3B Feedwater Regulating Valve [Charter Item No. 7 and No. 8]

3.1 Root Cause Investigation

The inspectors' assessment of the licensee's root cause investigation and Engineering Department's response was based on the following:

- Observing portions of the 3B FRV valve and actuator disassembly.
- Inspecting the failed valve internals.
- Observing portions of the 3B FRV reassembly.
- Observing the licensee's root cause team discussions and meetings.
- Reviewing the material analysis failure report, the root cause investigation final report, the design documents, and applicable calculations evaluating stem fatigue for short term operation.

Based on the laboratory material analysis of the stem's fracture surface and the as-found condition of the valve, the licensee concluded that the failure mechanism was low-stress, high-cycle fatigue cracking that originated from bending loads. These loads initiated and propagated two cracks on the stem. The inspectors reviewed the material analysis with regional specialist and concluded the analysis was technically sound.

The primary root cause that initiated the stem cracks was flow induced vibrations that were not necessarily accounted for in the design of the stem. Although the valve plug was within vendor clearance tolerances, based on wear indications on the plug's outer circumference, the plug was moving within the cage in a translation and angular motion. This flow induced vibration and the loads imposed on the stem may have been aggravated when the 3A FRV was taken out of service two weeks prior to the event. With total system flow passing through the 3B FRV, the potential existed for excessive localized vibration of the valve plug. Another possible contributor was a previously unnoticed eccentricity between the stem and plug of approximately 0.006 inch (the stem was not perfectly concentric with the plug). Analytically, this eccentric connection contributed little to the bending moments; however, it contributed to the overall loads at the stem and plug interface.

3.2 Corrective Actions

The licensee performed an analysis and determined that a like-for-like stem replacement was acceptable for the 6 months of operation remaining in the fuel cycle. A liquid penetrant test was performed on the replacement stem and no indications were identified. The licensee imposed an operational limit of 25 percent open on the 3B FRV to minimize valve stresses. Also, vibration monitoring of the valve was planned to identify the flow level at which the greatest frequency levels were reached. Finally, the licensee planned to modify the 3B FRV during the upcoming refueling outage in September 1996.

The analysis performed was a stress calculation to determine the induced stresses by the applied loads from the plug and guide to the valve stem. Based on this stress level, the number of cycles needed to fatigue the stem material to failure was predicted from American Society of Mechanical Engineers (ASME) "Stress versus Number of Cycles" graphs for the stem material. Based on the number of cycles to failure and the expected maximum operational time of 6 months, a maximum allowable frequency was calculated to analytically demonstrate that the valve stem will not reach its fatigue life in 6 months. Overall, the inspectors concluded that the licensee's short term corrective actions provided reasonable assurance that the 3B FRV would operate as designed until the upcoming refueling outage.

3.3 Engineering Response

After the failure of the 3B FRV, the licensee quarantined the valve and formed a Task Force to review the event, to identify the root causes of the equipment malfunctions (such as the FRV and the Group 1 relays), and to develop immediate and long term corrective actions for the failures. Senior licensee managers were assigned to provide dedicated oversight of the Task Force.

The engineering root cause team was effective in investigating and identifying the technical problems related to the valve failure. The licensee provided sufficient engineering resources and developed a multi-discipline team consisting of site and corporate engineering and technical specialists. Assembly and disassembly of the valve were well controlled and new information was methodically evaluated. Assumptions made by the investigative team were challenged and included a final independent review of the evaluation and of the corrective actions by two technical design engineering consultants. The inspectors concluded that the failure mechanism and the root cause were methodically determined and were technically founded.

3.4 Licensee's Decision to Operate with the 3A FRV Closed

The inspector's assessment of the licensee's decision to operate U-3 with total system flow passing through the 3B FRV was based on the following reviews:

- Licensee's engineering evaluation to close the 3A FRV.
- Updated Final Safety Analysis Report (UFSAR).
- Plant operating procedures.
- Feedwater system modifications.
- Feedwater system lesson plans.
- Control room operation logs.
- Interviews with operations personnel.

The body-to-bonnet steam leak on the 3A FRV was initially identified in September 1995. Repair parts were ordered, but were not available, when the plant was shut down twice in October 1995. During November 1995, the plant implemented a temporary modification to inject sealant to control the leakage. This sealant controlled the leakage but was not fully successful. Since November 1995, six sealant injections were made in an attempt to further control the leakage. Further, during planned load reductions in March 1996, the licensee again decided to continue sealant injections instead of repairing the leak, even though the materials for the repair were on site.

On April 27, 1996, the 3A FRV was closed and removed from service due to increased body-to-bonnet leakage. The plant was licensed to operate in this configuration in accordance with the UFSAR and plant operating procedures. Both the UFSAR and the procedures identified that feedwater level control with only the 3B FRV may produce flow oscillations due to irregular feedwater piping configurations. Section 10.4.7.2.1 of the UFSAR stated that 100 percent rated flow through a single FRV was not recommended since flow induced vibrations increased to unacceptable levels above 700 MWe. This statement was considered during the licensee's decision to operate with the 3A FRV closed. The licensee confirmed that the 3B FRV was passing less than 100 percent rated flow with power initially at 712 MWe. Additionally, engineering monitored and evaluated the vibrations after the feedwater system was operated in this configuration.

The inspectors agreed with the licensee's conclusion that the decision to isolate the 3A FRV focused primarily on the leak and personnel protection and not enough on the relationship of the FRV to the reactor. The licensee placed the plant in a position that required ECCS initiation following a failure of the 3B FRV. The inspectors concluded that the decision was non-conservative and was influenced by the unresolved material condition issues and the maintenance backlog on the feedwater system. Further, the inspectors concluded that the decision to isolate 3A FRV did not fully consider the potential impact on risk as described in the licensee's individual plant evaluation. Specifically, the feedwater system was a "key system" in minimizing core damage frequency, and operating with a single FRV increased the probability of system failure.

3.5 Historical Review of the FRVs and the Feedwater System

The inspectors review of the history of the FRVs and the feedwater system was based on the following:

- Previous modifications.
- Valve manufacturer technical information.
- Valve and actuator corrective and preventive maintenance work request.
- Component failure history information and corrective action.
- Industry failure information.
- Valve design documents and applicable calculations.

3.5.1 Copes Vulcan FRV

The original design of the U-2 and U-3 FRVs was a Copes Vulcan series D-100 valve with Copes Vulcan internals (stem, plug, cage, and guides). Valve stem related problems were noted with Copes Vulcan valves throughout the nuclear industry especially during the 1980's. The failure mode for most reported failures was related to retaining roll-pin cracks or loosening of a holding nut that allowed the plug to work free. Various modifications recommended by Copes Vulcan appeared to have been effective since very few failures of these types were reported since the early 1980's.

In 1987, a Dresden Unit 2 FRV plug separated from the stem after being in service for approximately 30 months. (The valve stem separated at approximately the same location as the 3B FRV in 1996.) The 1987 failure mechanism was attributed to fatigue, but no further review was performed to identify the root cause. [Note that an AIT was formed to review the 1987 event (Inspection Report 50-237/249-87029).] The stem and plug of the 2A FRV were replaced and welded together. Other corrective action included replacement of the all of the original Copes Vulcan FRV's internals with a modified trim (cage and plug assembly) to minimize vibration and fatigue. The Dresden Unit 3 3B FRV internals were modified in 1988.

In late 1991, based on the failure of similar type of Copes Vulcan valve at a different utility, the licensee inspected the FRVs and found cracking on the 3B FRV plug adjacent to the retaining pin. The licensee replaced the stem and modified the stem-to-plug connection (completed in March 1992). A schedule to inspect the valve stem every second refueling outage was developed. The 3B FRV was scheduled to be inspected in the Fall 1996. The licensee could not determine the basis for choosing a two outage inspection interval. Since the repair, the 3B FRV had been in service approximately 32 months.

The inspectors concluded that the licensee had not utilized available information to fully evaluate the proper inspection interval for the modified 3B FRV stem. The history of Copes Vulcan FRVs at Dresden was well documented, including in the 1987 AIT report, and the 3B FRV vibration problems were clearly described in the station's FSAR. However, no detailed engineering analysis was performed to support the inspection interval determination.

3.5.2 Feedwater System

The review of the feedwater system identified concerns with flow induced vibrations believed to be caused by irregular piping configurations throughout the system. Interactions between the feedwater control system and the FRVs, and the system's hydraulic instabilities have historically been a concern. A part of the licensee's long term corrective actions for the 1987 failure of the 2A FRV was a comprehensive review of the feedwater system. The review identified the need for system-wide modifications. The modifications were done slowly until 1994. However, since 1994, the modifications were more comprehensive and included additional valve internal replacements, valve operator replacements, and control and process system improvements. At the time of the May 15 event occurrence, the licensee was in the final stages of these modifications. As noted earlier, the valve internals for the 3B FRV were scheduled to be replaced during the Fall 1996 outage.

While significant progress was made in improving the feedwater system since 1987, the modification to the 3B FRV was still outstanding 9 years later. The 3B FRV stem had not been inspected for cracks since 1992 due to extended outages. The inspectors concluded that the licensee's modification backlog contributed to the event initiation.

4.0 Failure of the Group 1 Primary Containment Isolation System (PCIS) Valve Relays [Charter Item No. 5 and No. 9]

The inspector's assessment of the licensee's root cause investigation, corrective actions, and the Engineering Department's response was based on the following:

- Observing removal of two failed HGA relays.
- Observing the licensee's root cause testing performed by relay specialists.
- Reviewing the electrical schematics for all U-2 and U-3 Group 1 valves.
- Reviewing the U-2 relay operability evaluation.
- Reviewing the HGA relay dedication package.
- Reviewing the post maintenance verification test for the reinstalled relays.
- Reviewing the HGA relay failure history.

4.1 Design

The purpose of the PCIS was to provide automatic isolation of certain systems which penetrate the primary containment whenever setpoints were exceeded. The Group 1 isolation consisted of eight MSIVs, two main steam line drains, two isolation condenser steam line vents, and two recirculation loop sample valves. Whenever a setpoint was reached, the Group 1 isolation valves automatically closed. The circuit design used a control relay to provide a seal-in feature to prevent a valve from reopening following reset of the Group 1 isolation signal. When resetting the Group 1 isolation signal, these control relays should remain de-energized with the armature contacts "dropped-out" until the valves were manually reopened. The licensee determined that the seal-in relays for the two valves that unexpectedly reopened were de-energized but the armature contact had not "dropped out." With the armature contacts still closed, the two valves automatically reopened when the Group 1 isolation signal was reset.

4.2 Root Cause Investigation

When the Group 1 isolation signal was reset, the 1A MSIV and the 220-45 recirculation sample isolation valve unexpectedly reopened due to failed relays in these two valves' control circuits. The operators manually reclosed the two valves and reverified the other Groups 1 isolation valves were closed. The licensee quarantined the two control relay cabinets to preserve the as-found condition of the relays. The safety consequences of the valves reopening were minimal because redundant valves remained closed.

The relays used to perform the seal-in function for the Group 1 alternating current (AC) operated solenoid valves were General Electric (GE) model number 12HGA17S63. The HGA relays were "commercial grade" products that had been dedicated for safety related applications. At Dresden, model 12HGA17S63 relays were only used in the PCIS application. Twelve relays of this type were used in each Unit. Both of the failed relays had been in service since 1991.

One failed relay from the 1A MSIV and one relay from a valve circuit that had operated properly were removed and taken to Commonwealth Edison's Central Receiving, Inspection and Testing Facility (CRIT) for root cause analysis. The CRIT team identified the failed relay had mechanical binding of the moveable phenolic contact finger carrier block at the armature support bracket pivot points. The balanced armature was hinged at the support bracket pivot points and was supposed to freely move at this point to insure good contact wipe. The good relay's armature freely pivoted when mechanically manipulated. Disassembly of the failed relay required a screwdriver to pry the phenolic block from the armature plate and armature support bracket. The hinged armature plate freely pivoted around the pivot points once the phenolic block had been removed.

Critical relay part dimensions were measured by the CRIT team. Inside dimensional measurements of the failed relay phenolic block were found to be smaller than the good relay. In addition, the armature support bracket pivot point dimensions of the failed relay were larger than the good relay. The CRIT team concluded that manufacturing tolerances may have caused an interference fit at the pivot points. The CRIT team reassembled the failed relay and was able to recreate the mechanical binding.

The licensee concluded that the two Group 1 relays were mechanically bound due to an interference fit of the phenolic block at the armature support bracket pivot points. The dimensional variations could have occurred during manufacturing, such as the mold used to manufacture the phenolic block and/or stamping of the armature support bracket. The inspectors concluded that the licensee's cause determination was reasonable.

4.3 Corrective Actions

The licensee initiated prompt corrective actions to prevent unexpected valve repositioning upon resetting a Group 1 isolation signal. Caution tags were placed on each unit's Group 1 Main Steam Isolation Reset switches with instructions to manually close all Group 1 isolation valves prior to resetting a Group 1 signal. The inspectors reviewed the operability evaluation for the Unit 2 HGA relays and the electrical schematics for all Unit 2 and Unit 3 Group 1 valves and concluded that these actions would prevent spurious opening of the valves if other Group 1 seal-in relays were mechanically bound.

The CRIT team "dedicated" 12 HGA relays to be reinstalled in U-3. This included seven new relays and five relays originally installed since 1991. The inspectors reviewed the relay "dedication" package and post maintenance verification tests and concluded that the relays and the contacts operated satisfactorily. Other actions included preparation of a preliminary industry notification letter and review of the potential generic binding problems by the Station's 10 CFR Part 21 committee.

4.4 Engineering Response

Overall, the inspectors concluded that the licensee's root cause determination team was effective in investigating and identifying the technical problems with the relays. There was a good mix of station and corporate engineering and relay specialists to perform the root cause analysis. The analysis was conducted in a controlled, careful manner. Throughout the testing process, an approved test plan was used and the instructions were written in a logical manner that preserved the as-found condition of the relays.

4.5 Historical Review of the HGA Relays

The model 12HGA17S63 relays were installed in 1991 by Modification Package M12-3-88-060. Similar relays were installed in U-2 around the same time frame. The relays were dedicated for safety related applications. The inspectors reviewed the 1991 U-3 post modification test and concluded that the relays had been satisfactorily tested. At Dresden, the 12HGA17S63 model relay was only used in the PCIS application. Twelve relays of this type were used in each Unit. The relays were fully tested during each refueling outage during PCIS logic functional testing. Unit 3 Group 1 HGA relays were last tested on July 25, 1994, and U-2 relays were last tested on March 18, 1996. All relays operated as designed during the tests.

The inspectors reviewed industry notifications pertaining to the HGA relays. No problems associated with armature binding at the pivot points were identified. In addition, a search of industry failure records identified 1 out of 43 entries that involved a binding HGA relay. The binding relay was not a model 12HGA17S63. No binding problems were identified during a review of the failure history of the other model HGA relays used in safety related applications at Dresden.

The inspectors identified a concern with several missed opportunities to identify the relay binding problem. During 1994 and 1995, three corrective work requests (WRs) were written to repair sticking Group 1 HGA relays on U-2. A total of six relays were repaired or replaced as needed. These failures were not captured by the licensee's trending or generic corrective action programs. The two 1994 work requests had a job step for the system engineer or work analyst to determine if a generic problem existed. In both WRs, this job step was marked "NR" (not required). The work packages were reviewed by the Quality Control organization; however, the reviewer had not identified a concern that the generic problem review step was not completed. In addition, the WRs lacked sufficient detail to determine what corrective work was performed and that all contacts of the repaired or replaced relays had been thoroughly tested. The work packages focused on the MSIV white indicating lights not going out rather than the safety related drop-out of the seal-in contact following a Group 1 isolation signal. The inspectors concluded that the three U-2 corrective WRs were an indicator of potential binding problems that subsequently effected U-3 Group 1 HGA relays.

5.0 Isolation Condenser Performance and Radiological Impact of Event [Charter Item No. 10]

The inspector's assessment of the isolation condenser's (IsoCondenser) performance and the subsequent radiological impact were based on the following reviews:

- Radiological surveys.
- Offsite dose calculations.
- Chemistry sample results.
- Interviews with Radiation Protection (RP) and Chemistry personnel.
- Direct field observations.

Due to historical uses of contaminated condensate water to provide makeup water to the shell side of the IsoCondenser, residual low levels of radioactivity resided within the condenser. When the IsoCondenser was placed in operation, low levels of radioactivity were exhausted into the environment through the IsoCondenser steam vents. The RP and Chemistry departments dispatched technicians to isolate the area where the IsoCondenser steam was being released. This action mitigated any unnecessary exposures (even though small) to plant personnel.

Chemistry technicians collected water samples from various locations near the steam release point. Analytical results indicated that 10 of the samples contained detectable amounts of cobalt-60. The highest sample concentration reported was 1.4 E-06 μcuries/cm^3. This concentration was used to quantify the total activity and resultant dose associated with the release.

Calculations were performed to determine a conservative value of the volume of water exhausted from the IsoCondenser as steam. This volume was multiplied by the highest sample concentration and resulted in a total activity release of 447 μcuries of cobalt-60. This total was used to quantify an offsite release through airborne and liquid pathways. The calculated offsite dose equivalent for the airborne pathway to an adult was 7.12 E-03 mrem and for the liquid pathway for a child was 4.65 E-07 mrem. These offsite doses were below the limits specified in 10 CFR Part 50, Appendix I (3 mrem/year whole body).

The inspectors independently verified the calculations and methodology for determining the offsite doses. The NRC PCDOSE program was used during the verification process. The NRC calculations indicated that the licensee's methods were reasonable for the quantity of radioactivity considered released.

6.0 Performance of Plant Equipment [Charter Item No. 4]

In general, plant equipment performed as designed during the event and through the point of achieving Cold Shutdown. Based on interviews with the operators, there were no work-arounds, degraded equipment, out-of-service equipment, or malfunctioning equipment other than the PCIS relays, which interfered with the operators' ability to respond to the event. There were some unexpected alarms which the licensee determined were indicative of normal wear or were caused by the changing state (Start/Stop) of equipment. The following equipment anomalies were identified:

- Two Group 1 PCIS valves unexpectedly reopened when the Group 1 isolation signal was reset. The cause was a stuck relay in each of the valves' control circuits. There were no consequences because redundant Group 1 valves remained closed. These failed relays are discussed in Section 4.2.

- The 3B FRV stem failure resulted in complete loss of feedwater to the reactor. The cause was fatigue cracking. This issue is discussed in Section 3.1.

- One control rod display lost indication during the automatic reactor trip. There were no consequences because alternate indication was available on the Rod Worth Minimizer. The display returned to normal and functioned correctly during subsequent troubleshooting.

7.0 Operators' Responses and Procedure Adequacy [Charter Item No. 2]

The inspectors' assessment of the operators' responses to the event and of the procedural adequacy was based on a review of the following:

- Plant procedures (normal, abnormal, annunciator response, emergency).
- Control room logs - nuclear station operators (NSO), unit supervisors (US), and shift manager.
- Control room instrument chart recorders.
- Plant alarm and data print outs.
- Interviews with control room personnel.

- Licensed operator training lesson plans.
- Simulator scenarios.
- Field observations during the event.

7.1 Control Room Operators' Responses to the Event

The inspectors reviewed the information above to determine if the operators' initial responses and subsequent actions to control room indications were timely and in accordance with plant procedures.

- The NSOs' (licensed reactor operators) and US [unit supervisor (licensed senior reactor operator)] initial responses to the control room alarms were to evaluate all of the other indications and alarms on the main control board. Reactor water level dropped to the automatic reactor trip setpoint 7 seconds after the first alarms.

- After the reactor trip, the NSOs and US performed the immediate actions for a reactor trip, continued to monitor reactor water level, assessed the condition of the feedwater system, and entered multiple abnormal and annunciator response procedures. The NSOs were reviewing the HPCI initiation procedure when HPCI automatically started on Low-Low water level.

- After water level was restored to the normal band and HPCI injection had been reduced to minimum, HPCI was used to control reactor pressure. Level continued to increase until the HPCI turbine automatically tripped on high water level. The operators were hesitant to trip the HPCI turbine before the automatic setpoint because HPCI was a functioning source for pressure control and high pressure water injection.

- The Groups 1, 2, and 3 isolation signals were reset in order to restore the main condenser as an alternate heat sink (if needed) and the RWCU system for level control. When the signal was reset, two Group 1 valves unexpectedly reopened due to failed relays in the valves' control circuits. (See Section 7.2 for information on procedural inadequacy.)

- The plant was taken to Cold Shutdown using the IsoCondenser and the shutdown cooling (SDC) system. The cooldown was performed in a controlled fashion and no technical specification (TS) or administrative limits were exceeded.

- After the two Group 1 isolation valves unexpectedly reopened, the licensee declared an Unusual Event and activated the emergency plan due to the potential degradation in the level of plant safety. All notifications were performed as required.

The inspectors concluded that the operators performed the appropriate immediate actions, stabilized reactor water level and pressure, and placed the plant in a shutdown condition in accordance with plant procedures. The inspectors observed that NSOs monitored control room indications, supervisors maintained proper command and control, and 3-way communications were used throughout the event.

7.2 Procedure Adequacy

The inspector's identified minor discrepancies in four procedures that were used during the event.

- Dresden Annunciator Procedure (DAN) 903-5 D-4 "GROUP 1 ISOLATION INITIATED," Revision 5.

  Procedure DAN 903-5 D-4 was unclear regarding the actions necessary to reset a Group 1 isolation signal. Section A, "Automatic Actions," of the DAN listed the Group 1 valves which were expected to close on an isolation signal and had an asterisk (*) beside 12 of the 14 valves (e.g., AO 2(3)-203-1A*). There was a "Note" in the section B, "Operator Actions," ~~which~~ stated, "Control switches for asterisked (*) Group 1 valves must be in CLOSE before the isolation signal can be reset." The intent of the "Note," was to direct the operator to place the individual valve control switches to "close" prior to resetting the isolation signal. There were no interlocks, devices, or administrative aids to prevent resetting the isolation signal. Additionally, "Notes" in procedures were for information only and were not used to direct operator action. There was no specific step to reset the isolation signal. The licensee revised the DAN on May 22, 1996, to correct the deficiency.

- Dresden General Procedure (DGP) 02-03, "Reactor Scram Procedure," Revision 24.

  After the scram, two control rods did not indicate "00" on the full core display. The NSOs used the Rod Worth Minimizer (RWM) to verify that one control rod was fully inserted after the scram. Step D.2 of the scram procedure stated to check that all rods were inserted using OD-7 or the full core display. The RWM was not mentioned in the procedure. However, use of the RWM was consistent with the guidance in Lesson Plan (LP) 295L-S1, "DEOP 100 Reactor Control," Revision 1, which stated to look at the full core display, RWM, and/or run an OD-7 to obtain the control rod position. The licensee revised the procedure to incorporate the use of the RWM for verification of rod positions. The inspectors concluded that the use of the RWM was acceptable. The second control rod was verified fully inserted using an approved operator aid.

  As discussed above, two Group 1 valves reopened because relays in the control circuits failed. Based on additional reviews, the inspectors concluded that no specific guidance was provided on how to reset the Group 1 isolation signal or if any prerequisites were needed. The status of the relays could have been verified by checking the MSIV Pilot Solenoid Lights in the auxiliary electric equipment room. The licensee revised DGP 02-03 to place Group 1 valve switches to close and to check all MSIV Pilot Solenoid Lights prior to resetting the Group 1 isolation signal.

- Dresden Annunciator Procedure (DAN) 902(3)-3 A-10, "HPCI THRUST BRG WEAR ACTIVE FACE," Revision 3.

  During the HPCI start, the HPCI Thrust Bearing Wear Alarm momentary actuated. The DAN stated that the probable causes for this alarm were thrust bearing failure, abnormal shaft movement, or switch failure. Additionally this alarm indicated abnormal turbine rotor movement and may indicate impending turbine failure. The licensee determined that this was an expected alarm for sudden HPCI start. The licensee planned to revise the DAN.

- Dresden Operating Procedure (DOP) 2300-04, "HPCI System Shutdown," Revision 5.

  The steps in DOP 2300-04 were inadequate to correctly realign the HPCI auxiliary cooling water subsystem. By performing the steps in DOP 2300-04, the auxiliary cooling pump's flow path was isolated. The licensee revised the procedure to include the correct valve line up.

The inspectors concluded that the procedural deficiencies had not prevented the operators from placing the plant in a safe condition.

8.0 <u>Evaluation of the Licensee's Response to the Event</u> [Charter Item No. 3]

Prior to the NRC's decision to conduct an AIT, the licensee formed a 10-person Task Force to review the event, to identify the root causes of the equipment failures, and to develop immediate and long term corrective actions for the failures. Senior licensee managers were assigned to provide dedicated oversight of the Task Force. The licensee added personnel to the Team and formed separate groups to investigate the failures of the FRV, HGA relays, and other equipment; to assess the control room operators response to the event; and to evaluate the plant's overall response to the event. The inspectors' evaluations of the licensee's specific investigations were discussed earlier the report.

As part of the licensee's evaluation of the plant's overall response to the event, the condensate and feedwater systems were inspected and the licensee determined that no external damage existed. However, the licensee identified that the condensate booster pumps were operating warmer than usual. Subsequent borescope inspection of the inboard and outboard wear rings and pump internals found no problems. Design Engineering personnel evaluated the feedwater and condensate piping and various components and confirmed that the event's pressure transient was within the design basis of the system. The inspectors independently walked down portions of the condensate and feedwater system's piping, supports, and equipment. No visible external damage was identified.

In addition to the investigations described above, the licensee performed fuel integrity assessments to determine what effect the pressure and temperature transients had on an existing leaking fuel pin (identified in April 1995). Reactor coolant samples collected following the reactor trip indicated that dose equivalent iodine levels remained consistent with pre-trip levels and were below TS limits. However, a spike indicating increased concentrations of neptunium-239 (Np-239) was noted. Analysis of prior reactor coolant samples collected during power reductions confirmed that similar spikes had occurred in the past. Evaluation of the spike observed during this shutdown determined that the Np-239 increase was proportional to the magnitude of the power reduction. Based on reviews and analyses performed by a qualified nuclear engineer and by corporate fuel integrity engineers, the licensee determined that the reactor trip had no detrimental effect on the leaking fuel pin. Region based specialists reviewed the licensee's assessment and concluded the licensee's determination was reasonable.

The inspector's concluded that overall, the licensee's investigation was self critical and intensive. The root cause determinations were reasonable and technically sound. The systematic approach and depth of the investigation assured appropriate corrective actions were developed. The inspectors concluded that the existing engineering modification backlog contributed to the delays in completing the modifications on the 3B FRV. In addition, the station's maintenance backlog contributed to the delays in repairing the 3A FRV and in the missed opportunities to identify a possible trend in the failed HGA relays in 1994 and 1995.

9.0 Potential Generic Implications [Charter Item No. 6]

One of the line items of the AIT Charter was to determine if there were any generic issues identified as a result of this event. The inspectors identified three issues with potential generic implications.

9.1 GE Model 12HGA17S63 Relays

The HGA relays were "commercial grade" products that had been "dedicated" for safety related applications. At Dresden, this model was only used in the PCIS application. The licensee prepared a preliminary industry notification letter and the mechanical binding problem was being reviewed by the Station's 10 CFR Part 21 committee.

9.2 Procedure to Reset Group 1 Isolation Signal

The procedures to reset a Group 1 Isolation signal from two other ComEd boiling water reactors (BWRs) and from one non-ComEd utility were reviewed. One of the ComEd BWR procedures specifically directed taking the individual valves' control switches to close BEFORE resetting the Group 1 signal. The procedures from the other two sites directed that the individual valve control switches be closed AFTER resetting the Group 1 signal.

9.3 Copes Vulcan FRV Failure

The licensee reviewed equipment history to determine if other Copes Vulcan valves were used at Dresden which incorporated a similar design to the 3B FRV. No additional valves were identified; however, Copes Vulcan indicated to the licensee that four other nuclear power plants had similar valves and those plants were informed of the event through the "Nuclear Network."

10.0 Assessment of Licensee's Management Oversight of Followup to Event and Reaction to Issues and Problems. [Charter Item No. 11]

As stated above in Section 8.0, the licensee immediately formed a 10-person Task Force to review the event, to identify the root causes of the equipment failures, and to develop immediate and long term corrective actions for the failures. Senior licensee managers were assigned to provide dedicated oversight of the Task Force. The Task Force initially appeared to be narrowly focused on identifying and correcting the causes of the FRV and Group 1 isolation relay failures. Additionally, some members of the Task Force were involved with both the repair efforts and the root cause investigation. Licensee management recognized that a larger team with broad and distinct responsibilities was needed and subsequently assigned additional resources to the Task Force.

During the Task Force review of the transient, 37 "issues" (such as equipment failures, unexpected alarms, or other abnormal indications) were identified that required a more thorough investigation. The licensee identified 29 of the issues and the inspectors identified 8. The inspectors concluded that the licensee had adequately addressed each of the issues both in scope and in depth.

The inspector's also concluded that management's oversight of the Task Force resulted in a thorough investigation with a broad review that looked for generic implications.

11.0 Exit Interview

The team met with licensee representatives (identified below) during a public meeting on May 23, 1996, and summarized the purpose of the AIT, AIT charter items, and inspection findings. The team discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the team during the inspection.

PERSONNEL CONTACTED

Commonwealth Edison Company (ComEd)

T. Maiman, Senior Vice President-Nuclear Division
S. Perry, Dresden Site Vice President
M. Heffley, Dresden Station Manager
T. O'Conner, Operations Manager
R. Freeman, Plant Engineering Superintendent
P. Swafford, Maintenance Superintendent
P. Planing, Shift Operations supervisor
R. Fisher, Work Control Superintendent
R. Whalen, Staff Assistant-Station Manager
C. Howland, Radiation Protection Manager
Other members of ComEd Corporate and Dresden Site personnel.

U. S. Nuclear Regulatory Commission

H. Miller, Regional Administrator, RIII
G. Grant, Director, Division of Reactor Safety (DRS), RIII
C. Pederson, Director, Division of Nuclear Materials Safety, RIII
P. Hiland, Chief, Division of Reactor Projects (DRP), Branch 1, RIII
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J. Stang, Licensing Project Manager - Dresden, Office of Nuclear Reactor Regulation (NRR)
J. Strasma, Public Affairs Officer, RIII

Attachments:
1. Augmented Inspection Team Charter
2. Sequence of Events

Attachment 1

Augmented Inspection Team Charter - Dresden Unit 3 5/16/96

Examine the circumstances surrounding the May 15, 1996, Dresden Unit 3 reactor trip event including but not limited to the following:

1. Develop and validate the sequence of events and activities occurring just before and after the event.

2. Interview plant personnel and evaluate operator's response to the event and their ability to stabilize the plant and place it in a shutdown condition. Determine if personnel actions and procedural guidance were adequate.

3. Evaluate the licensee's actions during and following the event; include initial indicators, their response to the initial indicators, system operations that may have contributed to the event, management's response and the root cause determination.

4. Evaluate the performance of plant equipment during the event and following recovery from initial transient up to the point of achieving COLD SHUTDOWN.

5. Determine the cause for the Main Steam Isolation valve and the Reactor Recirculation Sample valve reopening following reset of the Group 1 isolation logic.

6. Determine generic implications of the event, if any.

7. Assess engineering organization effectiveness to investigate and identify the event's technical problems and their control of the investigation and root cause determination.

8. Determine if appropriate attention had been given to the Feedwater Regulating valves (FRVs) including corrective and preventive maintenance, prior to the event. Determine the problems associated with the FRVs and how long they have existed.

9. Determine if appropriate attention had been given to the Main Steam and Reactor Recirculation valve relays and other isolation logic relays including corrective and preventive maintenance.

10. Evaluate operation of the Isolation Condenser and assess significance of any radioactive release.

11. Assess licensee management oversight of the followup to the event and their reaction to the issues and problems identified.

Sequence of Events

NOTE: The time is listed using a 24 hour clock.
The units are hours:minutes:seconds, unless otherwise noted.
Information in Italics indicates an unexpected response.

Plant conditions on May 15, 1996, prior to the event.

Unit 3:
About 82 percent power (677 MWe) in coastdown.
Unit 3 had been on-line since November 15, 1995.
Normal offsite power and all ECCS available (for both units).
Routine quarterly surveillance testing of the containment cooling service water (CCSW) in progress.

The 3A FRV and its associated inlet isolation valve, MO-3206A, had been closed since April 27, 1996, due to a body-to-bonnet leak on the 3A FRV. The 3B FRV was controlling reactor water level in automatic at the normal operating level (about +30 in.). [Note that the top of active fuel (TAF) is -143 in.]

Unit 2:
About 55 percent power (457 MWe). Unit 2 had been on-line since April 20, 1996. Routine surveillance testing was in progress.

10:43:24
T= 00:00
First Indications of a Problem were Alarms on the U-3 Main Control Board.
- Feedwater Regulating Station Vibration High.
- 3B Feedwater Regulating Valve Actuator Low Oil Level.

10:43:28
T= 00:04
Reactor Vessel Water Low Level Alarm (+20 in.)

10:43:31
T= 00:07
Automatic reactor trip on low reactor level (+17 in.). All rods fully inserted.
Group 2 Isolations: drywell, reactor building, and turbine building ventilation systems isolated; standby gas treatment system automatically started.
Group 3 Isolations: RWCU and SDC systems.
All other equipment operated as designed.

10:43:33
T= 00:09
Operators performed the immediate actions of reactor scram procedure. Two control rods had not indicated position "00." The two rods were verified fully inserted using alternate indications.

10:44:43
T= 01:19
Reactor water Low-Low level trip signal (-51 in.).
Automatic initiation of HPCI and auto-start of the U-2 and U-2/3 EDGs. The EDGs were not required to supply power to the emergency busses.
Group 1 Isolations: 14 valves closed - 8 MSIVs, 2 Isolation Condenser vent valves, 2 reactor recirculation sample valves, and 2 main steam line drain valves.
The A and B reactor recirculation pumps tripped.
All other equipment operated as designed.

10:44:53
Lowest indicated vessel water level: -59 in.

T= 01:29	
10:45:02 T= 01:38	The HPCI system was injecting at full flow (about 6000 gpm) about 19 seconds after the start signal which was within UFSAR assumptions (UFSAR Table 6.3-7). Reactor vessel water level begins to increase due to HPCI and CRD systems injection.
10:45:05 T= 01:42	Reactor vessel water level Low-Low trip signal reset. As level increased, control room operators reduced HPCI injection flow to control vessel level.
10:45:08	Main turbine generator tripped as designed.
10:47:00	Reactor vessel water level was at +7 in.
10:47:35	Reactor Vessel Water Low Level Alarm cleared.
10:47:50 T= 04:36	The HPCI flow reduced to minimum. The HPCI system remained in service for reactor pressure control. Level was +28 in. Total volume of HPCI Injection was about 14,800 gallons.
10:51	Reactor pressure was at the lowest point prior to initiating a controlled cooldown: about 845 psig.
10:56	Torus cooling was placed in service. Torus temperature rise during entire event was about 4°F (71 to 75 °F).
10:57:18 T= 13:55	The HPCI turbine tripped on high vessel water level (+48 in). The CRD pump continued to inject water into the reactor.
11:01:05	Condensate and Feedwater pumps secured because sump pumps for the 3A and 3B turbine building equipment drains sumps and 3B turbine building floor drain sump were continuously running. (The 3C3 feedwater heater relief valve and a condensate/condensate booster pump suction relief valve had lifted.) *The 3C3 feedwater relief valve had not reseated quickly.*
11:01:37 T= 18:13	Isolation Condenser manually placed in service for reactor pressure control and cooldown.
11:02	Reactor pressure was at the highest level during event: about 1000 psig.
11:11:44 T= 28:20	Groups 1, 2, and 3 Isolation signals were reset. *The 1A MSIV and recirculation sample valve 220-45 unexpectedly reopened when the Group 1 signal was reset. The U-2 US identified that the 1A MSIV was open. The positions of the remaining Groups 1, 2, and 3 valves were re-verified closed.*
11:15:12	The 1A MSIV was closed by a NSO.
11:16	*Recirculation sample valve 220-45 was found open during the re-verification and closed by a NSO.*
11:22 T= 39:00	An Unusual Event was declared due to the potential degradation in the level of plant safety. All notifications were performed in a timely manner.

17:43	Secured Isolation Condenser. (T = 7 hours.)
17:48	Started 3B SDC Loop to continue cooldown.
18:55	Torus Cooling secured.
19:30	Reactor at Cold Shutdown. (T = 8 hours and 43 minutes.)
19:52	Started 3C SDC Loop for mixing. Maintaining reactor coolant temperature between 160 - 170 F.
20:03	Reset reactor trip in accordance with procedure.
23:08	Terminated Unusual Event. (T = 12 hours and 25 minutes.)