August 8, 2005

Rejane Spiegelberg-Planer
Operational Safety Experience Specialist
IAEA IRS Coordinator
International Atomic Energy Agency
Division of Nuclear Installation Safety
International Atomic Energy Agency
Wagramer Strasse 5
P.O. Box 100
A-1400 Wien
AUTRICHE

Dear Ms. Spiegelberg-Planer:

The following operating experience reports from United States reactors are enclosed for your consideration for including in the Advanced Incident Reporting System (AIRS) database:

NRC Information Notice 2005-11: Internal Flooding/Spray-Down of Safety-Related Equipment Due to Unsealed Equipment Hatch Floor Plugs and/or Blocked Floor Drains

NRC Information Notice 2005-14: Fire Protection Findings on Loss of Seal Cooling to Westinghouse Reactor Coolant Pumps

NRC Information Notice 2005-15: Three-Unit Trip and Loss of Offsite Power at Palo Verde Nuclear Generating Station

NRC Information Notice 2005-16: Outage Planning and Scheduling - Impacts on Risk

NRC Information Notice 2005-20: Electrical Distribution System Failures Affecting Security Equipment

NRC Information Notice 2005-21: Plant Trip and Loss of Preferred AC Power From Inadequate Switchyard Maintenance

NRC Information Notice 2005-23: Vibration-Induced Degradation of Butterfly Valves

Each report is being submitted in the following two media: (1) a hard copy of the input file for the AIRS database; and (2) a compact disc containing the input file for the AIRS database in WordPerfect format.

If you have any questions regarding these reports, please contact Brett A. Rini of my staff. He can be reached at 301-415-3931.

Sincerely,

/RA/
Patrick L. Hiland, Chief
Reactor Operations Branch
Division of Inspection Program Management
Office of Nuclear Reactor Regulation

Enclosures: As stated

cc w/enclosures:
Dr. Pekka T. Pyy
Administrator, Operating Experience & Human Factors
Nuclear Safety Division
Nuclear Energy Agency
OECD
Le Seine St. Germain, Batiment B
12, Boulevard des Iles
92130 - Issy-les-Moulineaux
FRANCE

If you have any questions regarding these reports, please contact Brett A. Rini of my staff. He can be reached at 301-415-3931.

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Patrick L. Hiland, Chief
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FRANCE

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ADAMS ACCESSION NUMBER: ML052150306

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NAME	BRini	IJung	MRoss-Lee	PLHiland	
DATE	08/04/2005	08/05/2005	08/05/2005	08/08/2005	

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INCIDENT REPORTING SYSTEM

IRS NO.	EVENT DATE	08/18/2004	DATE RECEIVED

EVENT TITLE

NRC Information Notice 2005-11: Internal Flooding/Spray-Down of Safety-Related Equipment Due to Unsealed Equipment Hatch Floor Plugs and/or Blocked Floor Drains

COUNTRY	PLANT AND UNIT	REACTOR TYPE
United States	Susquehanna 1	BWR

INITIAL STATUS	RATED POWER (MWe NET)
Full Power	1050

DESIGNER	1st COMMERCIAL OPERATION
Bechtel	1983

ABSTRACT

The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to inform addressees of the possibility of flooding safety-related equipment as a result of (1) equipment hatch floor plugs that are not water tight and (2) blockage of the equipment floor drain systems that are credited to mitigate the effects of flooding in the final safety analysis report (FSAR) and plant design basis calculations.

NRC INFORMATION NOTICE 2005-11

Please refer to the dictionary of codes corresponding to each of the sections below and to the coding guidelines manual.

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1. **<u>Reporting Categories</u>:**
   1.2.6
   1.4
   1.6

2. **<u>Plant Status Prior to the Event</u>:**
   2.0

3. **<u>Failed/Affected Systems</u>:**
   3.BG
   3.SC
   3.WF

4. **<u>Failed/Affected Components</u>:**
   4.2.8
   4.2.9
   4.3.4

5. **<u>Cause of the Event</u>:**
   5.1.1.6
   5.1.1.8
   5.1.6.4
   5.1.8.2

6. **<u>Effects on Operation</u>:**
   6.0

7. **<u>Characteristics of the Incident</u>:**
   7.5

8. **<u>Nature of Failure or Error</u>:**
   8.2
   8.4

9. **<u>Nature of Recovery Actions</u>:**
   9.3

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555-0001

May 6, 2005

NRC INFORMATION NOTICE 2005-11: INTERNAL FLOODING/SPRAY-DOWN OF SAFETY-RELATED EQUIPMENT DUE TO UNSEALED EQUIPMENT HATCH FLOOR PLUGS AND/OR BLOCKED FLOOR DRAINS

ADDRESSEES

All holders of operating licenses for nuclear power reactors, except those who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor vessel.

PURPOSE

The U.S. Nuclear Regulatory commission (NRC) is issuing this information notice (IN) to inform addressees of the possibility of flooding safety-related equipment as a result of (1) equipment hatch floor plugs that are not water tight and (2) blockage of the equipment floor drain systems that are credited to mitigate the effects of flooding in the final safety analysis report (FSAR) and plant design basis calculations.

It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions in this IN are not NRC requirements; therefore, no specific action or written response is required.

DESCRIPTION OF CIRCUMSTANCES

On August 18, 2004, during an extended backwash evolution on the reactor water cleanup demineralizer at Susquehanna Unit 1, approximately 1,500 gallons of contaminated water from the backwash-receiving tank overflowed into the reactor building equipment floor drain system. The drain header became blocked by the resin from the receiving tank and rust displaced from inside the drain pipes. The water flowed up and out of the blocked drains on a lower elevation, across the floor, and down into the Division II core spray and the high-pressure coolant injection system compartments. The water entered these compartments by flowing though unsealed spaces between the equipment hatch floor plugs and the floor. The equipment floor drains in the emergency core cooling system (ECCS) compartments were isolated, as per design, and the water accumulated on the floor. Approximately 2 inches of water accumulated on the floor of the Division II core spray and high-pressure injection system compartments.

ML050870351

The licensee disabled the automatic start feature of the Division II core spray pumps and declared the pumps inoperable but functional for approximately 2hours until an assessment was completed to verify operability. The licensee's immediate actions were to perform system walkdowns and determine the effect of the flooding on the Division II core spray and high-pressure coolant injection systems. The walkdowns determined that the water leakage into the room did not significantly impact the systems and that the systems remained operable. The walkdowns also confirmed that the other ECCS compartments were not affected.

DISCUSSION

The licensee's FSAR flooding analysis stated that the ECCS compartments were water tight. However, the equipment hatch floor plugs were not sealed and therefore did not constitute a water-tight barrier. The plant-specific design calculations did not address leakage around these plugs. Water leaked through the ceiling into the Division II core spray and high-pressure coolant injection compartments through gaps between the equipment hatch floor plug and the floor. The licensee did not scope the equipment floor drain system function (mitigating internal flooding) into the Maintenance Rule. The FSAR and flooding design calculations credited the equipment floor drain system to assist in removal of water from internally flooded areas. Part of the licensee's corrective actions were to place the floor and equipment drain functions within the scope of the Maintenance Rule and to revise the plant calculations to reconcile the plant design analysis and the FSAR. The licensee has also developed and installed a modification to seal the equipment hatch floor plugs above the ECCS compartments.

CONCLUSION

The event described above illustrates the potential for degradation of multiple trains of ECCS as a consequence of potential flooding of safety-related equipment outside containment. All holders of reactor operating licenses should be aware of the effect of unsealed equipment hatch floor plugs and malfunctioning drains on their plant-specific FSARs and plant design analyses for flooding. Unsealed reactor building equipment hatch floor plugs and less than optimal maintenance monitoring of the equipment floor drain systems can result in additional internal flooding vulnerabilities. Licensees should consider several actions to mitigate these vulnerabilities:

(1) Verify that the actual plant configuration and design of the equipment hatch floor plugs meet the FSAR description and design basis calculations for water-tight compartments. Consider appropriate actions to achieve floor plug water tightness, such as the use of gaskets and sealers. Additionally, if the analysis allows for leakage through the equipment hatch floor plugs, the qualification of equipment below these plugs should consider water spray as well as submergence.

(2) In addition, if the drain system is required for water removal, periodically verify that the floor drain system performs as intended and perform maintenance to assure that the system can perform the water removal function assumed in the FSAR and design calculations.

GENERIC IMPLICATIONS

Flooding due to internal causes has been shown to be a significant contributor to risk at some facilities. Flooding also has the potential to make multiple trains of equipment and support equipment inoperable, significantly increasing plant risk. Flooding also has the significant consequence of preventing or limiting operator mitigation and recovery actions. As a result, semiannually, NRC inspectors select one or two plant areas and inspect internal flood protection features for risk-significant structures, systems, and components in accordance with Inspection Procedure Attachment 71111.06 "Flood Protection Measures."

Multiple previous NRC generic communications have addressed flood protection issues:

1. Circular CR 78-06 — POTENTIAL COMMON MODE FLOODING OF ECCS EQUIPMENT ROOMS AT BWR FACILITIES

2. IN 83-44 — POTENTIAL DAMAGE TO REDUNDANT SAFETY EQUIPMENT AS A RESULT OF BACKFLOW THROUGH THE EQUIPMENT AND FLOOR DRAIN SYSTEM

3. IN 83-44 S1 — POTENTIAL DAMAGE TO REDUNDANT SAFETY EQUIPMENT AS A RESULT OF BACKFLOW THROUGH THE EQUIPMENT AND FLOOR DRAIN SYSTEM

4. IN 87-49 — DEFICIENCIES IN OUTSIDE CONTAINMENT FLOODING PROTECTION

5. IN 92-69 — WATER LEAKAGE FROM YARD AREA THROUGH CONDUITS INTO BUILDINGS

6. IN 94-27 — FACILITY OPERATING CONCERNS RESULTING FROM LOCAL AREA FLOODING

7. IN 98-31 — FIRE PROTECTION SYSTEM DESIGN DEFICIENCIES AND COMMON-MODE FLOODING OF EMERGENCY CORE COOLING SYSTEM ROOMS AT WASHINGTON NUCLEAR PROJECT UNIT 2

CONTACTS

This IN requires no specific action or written response. Please direct any questions about this matter to the technical contact(s) listed below or the appropriate Office of Nuclear Reactor Regulation (NRR) project manager.

/Original Signed by Eric J. Benner/
Patrick L. Hiland, Chief
Reactor Operations Branch
Division of Inspection Program Management
Office of Nuclear Reactor Regulation

Technical Contacts:	Alan Blamey, R-I/DRP	Ross Telson, NRR
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Note: NRC generic communications may be found on the NRC public Web site, http://www.nrc.gov, under Electronic Reading Room/Document Collections.

INCIDENT REPORTING SYSTEM

IRS NO.	EVENT DATE	N/A	DATE RECEIVED

EVENT TITLE

NRC Information Notice 2005-14: Fire Protection Findings on Loss of Seal Cooling to Westinghouse Reactor Coolant Pumps

COUNTRY	PLANT AND UNIT	REACTOR TYPE
US	Surry	PWR
INITIAL STATUS	**RATED POWER (MWe NET)**	
N/A	855	
DESIGNER	**1st COMMERCIAL OPERATION**	
Westinghouse	1972	

ABSTRACT

The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to inform addressees about recent inspection findings on post-fire procedural requirements related to loss of cooling to reactor coolant pump (RCP) seals.

NRC INFORMATION NOTICE 2005-14

Please refer to the dictionary of codes corresponding to each of the sections below and to the coding guidelines manual.

---

1. Reporting Categories:
   1.22
   1.4

2. Plant Status Prior to the Event:
   2.0

3. Failed/Affected Systems:
   3.AE

4. Failed/Affected Components:
   4.2.1

5. Cause of the Event:
   5.1.6.8
   5.1.4.2

6. Effects on Operation:
   6.0

7. Characteristics of the Incident:
   7.11.4

8. Nature of Failure or Error:
   8.1

9. Nature of Recovery Actions:
   9.1.1

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555-0001

June 1, 2005

NRC INFORMATION NOTICE 2005-14: FIRE PROTECTION FINDINGS ON LOSS OF SEAL COOLING TO WESTINGHOUSE REACTOR COOLANT PUMPS

ADDRESSEES

All holders of operating licenses for pressurized water reactors, except those who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor vessel.

PURPOSE

The U.S. Nuclear Regulatory Commission is issuing this information notice (IN) to inform addressees about recent inspection findings on post-fire procedural requirements related to loss of cooling to reactor coolant pump (RCP) seals. NRC anticipates that recipients will review the information for applicability to their facilities and consider taking actions, as appropriate, to avoid similar issues. However, no specific action or written response is required.

BACKGROUND

Assuming a fire results in loss of cooling to the RCP seals, licensees may comply with 10 CFR Part 50, Appendix R, “Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979,” by protecting the cooling to the seals or by demonstrating that the plant can cope with RCP seal leakoff flow rates. Many licensees have installed RCP seal packages using high-temperature O-rings that will not result in uncontrolled leakage from RCP seals for conditions with loss of all RCP seal cooling. Licensees also ensure adequate makeup capability to compensate for any RCP seal leakoff and maintain reactor coolant system (RCS) inventory according to requirements of Appendix R, Sections III.G.2, III.G.3, and III.L.1 and performance goals of Appendix R, Section III.L.2. Note that a plant licensed before January 1, 1979, must meet the provisions of Appendix R, Section III.G and III.L and a plant licensed after January 1, 1979, must implement the fire protection provisions of its operating license.

ML051080499

DESCRIPTION OF CIRCUMSTANCES

At Surry, NRC inspectors found that certain postulated fires could result in the loss of cooling to the RCP seals. The inspectors noted that the RCP seal vendor, Westinghouse, advised that increased seal leakage, to around 21 gpm, could occur if seal cooling is lost and not restored before hot RCS fluid reaches the RCP seals. Additionally, the Westinghouse Owners Group (WOG) revised their generic emergency response guidelines for the station blackout event to recommend that RCP seal cooling not be restored following a prolonged loss of seal cooling in which the seal temperature exceeds the RCP seal vendor's recommendations. The licensee incorporated this guidance into its emergency operating procedures for the response to a loss of all alternating current (AC) power event but not in its procedures for safe shutdown of the reactor after a fire. Restoration of seal injection after the seals become hot could lead to increased leakage beyond the RCS makeup capability needed to satisfy the performance goals in Appendix R, Section III.L.2 (NRC Inspection Reports 50-280/03-07 and 50-281/03-07).

Similar findings were made at other nuclear power plants. At Turkey Point, NRC inspectors found that the post-fire procedures did not provide timely operator action to restore seal injection and could result in increased RCP seal leakage beyond the capacity of equipment dedicated to achieve and maintain post-fire safe shutdown according to Appendix R, Section III.G.2 (NRC Inspection Reports 50-250/04-07 and 50-251/04-07). At North Anna, NRC inspectors found, similar to the Surry finding, that certain fires could result in a loss of seal cooling. Seal cooling could be restored after the seal had heated up, thereby potentially resulting in increased seal leakage beyond the RCS makeup capability required to satisfy Appendix R, Section III.L.2 (NRC Inspection Reports 50-338/03-06 and 50-339/03-06). At Summer, the inspectors were concerned that the licensee's fire emergency procedure did not direct personnel to reestablish seal cooling flow in a timely manner, potentially leading to increased seal leakage beyond the RCS makeup capability needed to satisfy Appendix R, Section III.L.2 (NRC Inspection Report 50-395/01-10).

DISCUSSION

The NRC uses “deterministic” information to determine the existence of performance deficiencies. The risk significance of an identified performance deficiency is evaluated using probabilistic risk assessment (PRA) models.

In each case cited above, the NRC inspectors attributed the performance deficiency to inconsistent recovery procedures. They observed that the plant emergency procedures for a loss of all AC power did not agree with the plant procedures for mitigating the effects of a postulated fire. The post-fire procedures failed to direct plant personnel to restore RCP seal cooling before the seal temperature exceeds the vendor-specified limit. The inspection findings from Turkey Point also indicate that the fire mitigation procedures fail to consider that restoration of seal cooling is a time-critical operator action.

For seal packages in general, the makeup capability must exceed the seal leakoff to ensure that a hot standby condition can be achieved (according to the requirements in Appendix R, Section III. L.1. (c) and that the pressurizer level is maintained in the indicating range (according to the performance goals in Appendix R, Section III L.2.b). Furthermore, protecting seal integrity would be assisted if procedures for operating equipment needed for post-fire shutdown are consistent with vendor recommendations. For the Westinghouse RCP seals, as discussed in a recently submitted document on RCP seal performance (Reference 3), a leakage rate of 21 gpm per RCP may be assumed in the licensee's safe shutdown assessment following the loss of all RCP seal cooling. Assumed leakage rates greater than 21 gpm are only warranted if increased seal leakage is postulated as a result of deviations from seal vendor recommendations. Test or operating experience may be used to justify other RCP seal leakage rates.

Licensees with Westinghouse RCP seals have developed fire emergency procedures to cope with a loss of all RCP seal cooling by either reestablishing seal cooling to the RCPs before increased seal leakage occurs (to prevent increased leakage) or by providing sufficient RCS makeup to achieve and maintain post-fire safe shutdown.

Performance deficiencies and violations of regulatory requirements can result from all of the following: (1) procedural deviations from the manufacturer's recommendations without a documented basis, (2) inadequate procedures, and (3) inadequate documented analysis to show that Appendix R, Section III.L requirements are met.

If a performance deficiency exists, it is evaluated in the significance determination process (SDP) using PRA models. The loss of RCP seal cooling has been extensively modeled in PRA applications. In particular, the NRC used PRA information from its closure of a generic safety issue involving RCP seal failure (Reference 1) and from its safety evaluation of an industry model of RCP seal leakage (Reference 2) as the SDP framework to evaluate the risk significance of certain fire protection inspection findings. In the Surry case, the NRC estimated that the increase in the core damage frequency was between 1E-6 and 1E-5 per year (a white inspection finding). This finding is highly dependent on the plant-specific electrical switchgear room arrangement and the fire mitigation strategy.

In the recently submitted document on RCP seal performance (Reference 3), the NRC has not found sufficient new information to improve PRA models from previously issued industry models (Reference 4) or safety evaluation reports (Reference 2).

The PRA modeling considers two cases. In case 1 (plants with Westinghouse high-temperature O-rings and seals), Westinghouse, the RCP seal vendor, states that after loss of seal cooling, the seals with high-temperature O-rings will leak at about 21 gpm per pump. If the licensee implements vendor guidelines, this condition is not expected to proceed to failures resulting in leak rates greater than 21 gpm per pump. Even if seal cooling is not reestablished, degradation of the seals for leakage rate to significantly increase is not expected for an indefinite period of time if the RCPs are secured before the seal temperature exceeds 235 degrees F. Restoration of seal cooling may result in cold thermal shock of the seal and possibly cause increased seal leakage. If seal cooling is restored using component cooling water (CCW) to the thermal barrier cooler, water hammer may occur and possibly compromise the integrity of the CCW system. As discussed in the recently submitted document on RCP seal performance (Reference 3), if the CCW system is damaged, then plant shutdown after a fire accident may not be possible in all scenarios.

To be consistent with 10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” protection of seal integrity depends on fire protection and RCP recovery procedures being consistent with the manufacturer’s recommendations and that the associated instrumentation, alarms, and recovery procedures are available after a fire.

In case 1 (plants with Westinghouse high-temperature O-rings and seals), the NRC PRA modeling accounts for two failure scenarios, given a loss of seal cooling with no RCPs operating. In failure scenario 1 (hot shock), during initial heating of the seals, hydraulic instability caused by fluid flashing can potentially open (pop) the second-stage seal faces (Reference 2). For this scenario, the NRC PRA model assumes that the popping failure of the second-stage seal occurs at 13 minutes after loss of RCP seal cooling.

In case 1, failure scenario 2 (cold shock), if RCP seal cooling is restored after the seal temperature exceeds the vendor-specified limit, given survival from the initial hot shock of the seals, the NRC uses seal failure probabilities and consequential seal leakage sizes similar to those used in failure scenario 1.

In case 2 of the NRC PRA model (Westinghouse plants with “old,” pre-high-temperature RCP seals), Westinghouse, the RCP seal vendor, states that after loss of seal cooling, the “old” seals could fail after about 30 minutes. Therefore, protection of seal integrity requires the restoration of seal cooling within the appropriate time limit. However, this time limit is approximate. Plant-specific vendor guidance may differ based on (1) commitments made with respect to the station blackout analysis and (2) licensee-specific vendor recommendations.

CONTACT

This information notice requires no specific action or written response. Please direct any questions about this matter to the technical contact(s) listed below or the appropriate NRR project manager.

/RA/
Patrick L. Hiland, Chief
Reactor Operations Branch
Division of Inspection Program Management
Office of Nuclear Reactor Regulation

Technical Contacts:

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Attachment: References

Note: NRC generic communications may be found on the NRC public Web site, http://www.nrc.gov, under Electronic Reading Room/Document Collections.

REFERENCES

1. NRC Regulatory Information Summary 2000-002, “Closure of Generic Safety Issue 23, Reactor Coolant Pump Seal Failure,” February 15, 2000 (ADAMS ML003680402)

2. NRC Office of Nuclear Reactor Regulation, “Safety Evaluation of WCAP-15603, Revision 1, WOG 2000 Reactor Coolant Pump Seal Leakage Model for Westinghouse PWRs,” Westinghouse Owners Group Project No. 694, May 2003 (ADAMS ML0314003760)

3. Westinghouse Owners Group, “Reactor Coolant Pump Seal Performance for Appendix R Assessments,” WCAP-16396-NP, Revision 0, January 2005 (ADAMS ML050320187)

4. Westinghouse Electric Company, LLC, “WOG 2000 Reactor Coolant Pump Seal Leakage Model for Westinghouse PWRs,” WCAP-15603, Revision 1, May 2002 (ADAMS ML021500485)

INCIDENT REPORTING SYSTEM

IRS NO.	EVENT DATE	6/14/2004	DATE RECEIVED

EVENT TITLE

NRC Information Notice 2005-15: Three-Unit Trip and Loss of Offsite Power at Palo Verde Nuclear Generating Station

COUNTRY
US

PLANT AND UNIT
Palo Verde

REACTOR TYPE
PWR

INITIAL STATUS
At Power

RATED POWER (MWe NET)
1335

DESIGNER
Combustion CE80

1st COMMERCIAL OPERATION
1986-1988

ABSTRACT

The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice (IN) to alert addressees to electrical equipment failures and design deficiencies identified following recent transients at Palo Verde Nuclear Generating Station (PVNGS), Units 1, 2, and 3.

NRC INFORMATION NOTICE 2005-15

Please refer to the dictionary of codes corresponding to each of the sections below and to the coding guidelines manual.

---

1. **Reporting Categories:**
   1.3.1
   1.4
   1.7

2. **Plant Status Prior to the Event:**
   2.1.1

3. **Failed/Affected Systems:**
   3.EA

4. **Failed/Affected Components:**
   4.3.1
   4.3.2
   4.3.7

5. **Cause of the Event:**
   5.1.1.1
   5.1.2.5

6. **Effects on Operation:**
   6.1.1

7. **Characteristics of the Incident:**
   7.9

8. **Nature of Failure or Error:**
   8.2

9. **Nature of Recovery Actions:**
   9.1

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555-0001

June 1, 2005

NRC INFORMATION NOTICE 2005-15: THREE-UNIT TRIP AND LOSS OF OFFSITE POWER AT PALO VERDE NUCLEAR GENERATING STATION

ADDRESSEES

All holders of operating licensees for nuclear power reactors, except those who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor vessel.

PURPOSE

The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to alert addressees to electrical equipment failures and design deficiencies identified following recent transients at Palo Verde Nuclear Generating Station (PVNGS), Units 1, 2, and 3. As a result, the units lost offsite power, tripped, and experienced other problems, including the loss of an emergency diesel generator (EDG). It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements; therefore, no specific action or written response is required.

DESCRIPTION OF CIRCUMSTANCES

On June 14, 2004, at 7:41 a.m. Mountain Standard Time (MST), the 500 kV system upset at the PVNGS switchyard originated with a fault across a degraded insulator on a 230 kV transmission line. Protective relaying detected the fault and isolated the line from the remote substation. The protective relaying scheme at the other substation received a transfer trip signal actuating an auxiliary relay (Westinghouse Type AR) in the tripping scheme for two breakers connected to the faulted line. The AR relay had four output contacts, all of which were actuated by a single lever arm. The tripping scheme used two contacts in redundant trip coils for each breaker.

One breaker tripped, demonstrating that the AR relay coil picked up, and at least one of the AR relay contacts closed. The other breaker did not trip. Bench testing of the AR relay

ML050490364

showed that, even with normal voltage applied to the coil, neither of the tripping contacts for the failed breaker closed. The breaker failure scheme for the failed breaker featured a design where the tripping contacts for the respective redundant trip coils also energized redundant breaker failure relays. Since the tripping contacts for the failed breaker apparently did not close, the breaker failure scheme was not activated, resulting in a persistent uncleared fault on the 230 kV line.

Various transmission system event recorders show that, during approximately the first 12 seconds after fault inception, several transmission lines on the interconnected 69 kV, 230 kV, 345 kV, and 500 kV systems tripped on overcurrent. Also during the first 12 seconds, three cogeneration plants tripped, two with combustion turbines and one with a steam turbine, and the fault alternated between a single-phase-to-ground fault and a two-phase-to-ground fault, apparently as a result of a failed shield wire bouncing on the faulted line. After 12 seconds, the fault became a three-phase-to-ground fault and additional 500 kV lines tripped.

Approximately 17 seconds after fault inception, the three transmission lines between the PVNGS switchyard and the nearby 500 kV substation tripped simultaneously due to the action of their negative sequence relaying, thereby isolating the fault from the several cogeneration plants connected to that substation. Approximately 24 seconds after fault inception, the last two 500 kV lines connected to the PVNGS switchyard tripped, isolating the PVNGS switchyard from the transmission system. At approximately 28 seconds after fault inception, the three PVNGS generators were isolated from the switchyard and, by approximately 38 seconds, all remaining lines feeding the fault had tripped and the fault was isolated.

The trips resulted in a total loss of nearly 5,500 megawatts electric of local electric generation. Because of the loss of offsite power (LOOP), a Notice of Unusual Event was declared for all three Palo Verde units at approximately 7:50 a.m. MST. The Unit 2 train A emergency diesel generator started but failed early in the load sequence process due to a diode which short-circuited. The subject diode had less than 70 hours of run time in the exciter rectifier circuit. As a result, the train A engineered safeguards features busses deenergized, limiting the availability of certain safety equipment for operators. Because of this failure, the emergency declaration for Unit 2 was elevated to an Alert at 7:54 a.m. MST. All three units were safely shut down and stabilized under hot shutdown conditions. Units 1, 2, and 3 were without offsite power for approximately 4 hours and 9 minutes, 1 hour and 46 minutes, and 2 hours 15 minutes, respectively.

DISCUSSION

External fouling on a 230 kV insulator resulted in the deenergizing of a 500 kV switchyard, removing all sources of power to three nuclear units. The single-failure susceptibility of a transmission line protective system was the primary cause of the cascading blackout.

The insulator degradation was caused by external fouling and did not, by itself, represent a concern about the reliability of the insulators on the 230 kV transmission system. Nevertheless, the failed AR relay and the lack of a robust tripping scheme raised concerns about the maintenance, testing, and design of 230 kV system protective relaying. The 230 kV substation where the relay failure occurred was subject to annual maintenance and testing. Following the event, the failed AR relay was visually inspected. No apparent signs of contamination or deterioration were found.

As noted earlier, the tripping scheme lacked redundancy that could have prevented the failure of the protective scheme to clear the fault. The review of the design of the substations connected to the PVNGS switchyard indicated that two transmission lines at the subject substation featured a tripping scheme with only one AR relay. The newer lines had two AR relays. However, the review found that the bus-sectioning breakers at the subject substation contained only one trip coil instead of two trip coils.

To improve reliability, the tripping schemes for the two identified lines were modified to have two AR relays energizing separate trip coils for each breaker. The utility is considering installation of two trip coils in all single-trip-coil breakers. The tielines that connected 500 kV and 230 kV switchyards did not have overcurrent or ground fault protection. The installation of overcurrent protection for these tielines were completed in a later modification.

The apparent failure of the Unit 2 train A EDG was a failed diode in phase B of the voltage regulator exciter circuit. The diode failure resulted in a reduced excitation current and the current was unable to maintain the voltage output with the applied loads. The failed EDG did not have a significant impact on plant stabilization and recovery, but it did result in limited availability of certain safety equipment during a design basis event.

Refer to Attachment 1 for additional discussion.

CONTACTS

This information notice requires no specific action or written response. Please direct any questions about this matter to the technical contact(s) listed below or the appropriate Office of Nuclear Reactor Regulation (NRR) project manager.

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Note: NRC generic communications may be found on the NRC public Web site, http://www.nrc.gov, under Electronic Reading Room/Document Collections.

Attachment (exempt from public disclosure in accordance with 10 CFR 2.390)

INCIDENT REPORTING SYSTEM

IRS NO. **EVENT DATE** **N/A** **DATE RECEIVED**

EVENT TITLE

NRC Information Notice 2005-16: Outage Planning and Scheduling - Impacts on Risk

COUNTRY	PLANT AND UNIT	REACTOR TYPE
United States	Many	GEN

INITIAL STATUS
Shutdown

RATED POWER (MWe NET)
N/A

DESIGNER
N/A

1st COMMERCIAL OPERATION
N/A

ABSTRACT

The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to inform addressees about recent experiences in which outage planning and scheduling and adverse human performance for pressurized water reactors (PWRs) and boiling water reactors (BWRs) have had a significant impact on shutdown risk.

NRC INFORMATION NOTICE 2005-16

Please refer to the dictionary of codes corresponding to each of the sections below and to the coding guidelines manual.

---

1. Reporting Categories:
   1.2.5
   1.3.3
   1.4

2. Plant Status Prior to the Event:
   2.3

3. Failed/Affected Systems:
   3.AE
   3.BE
   3.CA

4. Failed/Affected Components:
   4.2.3
   4.2.6
   4.2.9

5. Cause of the Event:
   5.1.2
   5.1.2.6
   5.3.3
   5.4.3
   5.5.7

6. Effects on Operation:
   6.0

7. Characteristics of the Incident:
   7.0
   7.4
   7.5

8. Nature of Failure or Error:
   8.1

9. Nature of Recovery Actions:
   9.1.2

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555-0001

June 20, 2005

NRC INFORMATION NOTICE 2005-16: OUTAGE PLANNING AND SCHEDULING - IMPACTS ON RISK

ADDRESSEES

All holders of operating licensees for nuclear power reactors, except those who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor vessel.

PURPOSE

The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to inform addressees about recent experiences in which outage planning and scheduling and adverse human performance for pressurized water reactors (PWRs) and boiling water reactors (BWRs) have had a significant impact on shutdown risk. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements; therefore, no specific action or written response is required.

BACKGROUND

The NRC has published numerous reports on the generic issue of shutdown risk and specific outage events, including NUREG-1269, “Loss of Residual Heat Removal System, Diablo Canyon Unit 2,” April 10, 1987; NUREG-1410, “Loss of Vital AC Power and the Residual Heat Removal System During Mid-Loop Operations at Vogtle Unit 1", on March 20, 1990; and NUREG-1449, “Shutdown and Low-Power Operation at Commercial Nuclear Power Plants in the United States, Final Report,” dated September 1993. In response to the various studies and events, the NRC has also issued generic communications to highlight the importance of shutdown safety measures to the industry. The generic communications included Bulletin 80-12, “Decay Heat Removal System Operability," Generic Letter (GL) 87-12, "Loss of RHR While the RCS is Partially Filled," and GL 88-17, “Loss of Decay Heat Removal.” This listing of NRC documents regarding the control of shutdown activities and risk is not all inclusive and other relevant studies and generic communications have been issued in this area. For example, NUMARC 91-06, “Guidelines for Industry Actions to Assess Shutdown Management,” dated December 1991, provides guidance to licensees on managing shutdown safety issues.

ML050870005

DESCRIPTION OF CIRCUMSTANCES

Seabrook, a four loop Westinghouse PWR, has taken the initiative to develop an all-modes probabilistic safety assessment model. Following issues identified during a recent refueling outage, the risk associated with early midloop draindown and shutdown operations over a seven day period was determined to be roughly equivalent to operating at full power for an entire year. The instantaneous risk associated with draining the vessel to mid-loop exceeded $1.0x10^{-3}$ core damage frequency per year. This high instantaneous risk was discussed in other NRC and industry studies, including the EPRI report, “Low Power and Shutdown Risk Assessment Benchmarking Study,” dated December 2002. The Seabrook analysis provides a relatively recent comparison of reactor risk.

During recent refueling outages, several work activities were conducted without appropriate planning, resulting in challenges to operators and to the decay heat removal system. In each case, operators responded appropriately and anomalous plant conditions were returned to normal. However, continued attention is needed for work planning and execution during these high-risk periods.

- At Point Beach Unit 1, the licensee authorized installation of the hot leg nozzle dams prior to establishing an adequate reactor coolant system (RCS) vent path. The plant was in midloop operations and the outage schedule had called for the pressurizer manway to be removed to establish an RCS vent path before installation of the hot leg nozzle dams. Due to unanticipated delays in removing the pressurizer manway, several licensed and experienced personnel (including the shift outage manager, the outage control center operations representative, the work control center supervisor, and the shift manager on shift at the time) decided to begin installing the hot leg nozzle dams before removing the manway. Fortuitously, problems delayed the installation of the hot leg nozzle dams. The nozzle dams were not completely installed before the personnel realized that installation of the hot leg nozzle dams without a RCS vent path would have had a significant adverse impact on safety. Without an adequate vent path, the RCS would become pressurized following a loss of shutdown cooling. If one of the cold leg nozzle dams became dislodged, RCS inventory would quickly be discharged from the vessel and the core could be uncovered within a very short time.

- During a Millstone Unit 2 refueling outage, shutdown cooling was temporarily lost when the shutdown cooling heat exchanger outlet valve inadvertently closed and the heat exchanger bypass valve opened. The valves changed position due to an instrument bus power failure caused by an error in the procedure to synchronize the power supplies to the instrument bus. Shutdown cooling was lost for 13 minutes and the RCS temperature increased by approximately 14 degrees F. An Unusual Event was declared for an uncontrolled heatup of the RCS greater than 10 degrees F. The risk significance of this event was mitigated because operators had not completed preparations to drain the reactor vessel to midloop operations. During previous outages this maintenance activity had been performed with the power to shutdown cooling valves secured, and later in the outage when decay heat was lower.

- Calvert Cliffs Unit 1 had a partial loss of shutdown cooling during midloop operations. Both component cooling water (CCW) heat exchangers were in service at the time of the event. Salt water cooling flow to one CCW heat exchanger was lost when the heat exchanger outlet valve failed closed. The valve closure was caused by the loss of power to the valve controller when a control room maintenance activity inadvertently grounded which resulted in the loss of power to an instrument bus and valve controller. The maintenance activity that resulted in the grounded instrument bus should not have been performed during midloop operations. Decay heat removal from one of the two operating component cooling water heat exchangers, which were cooling two shutdown cooling trains, was lost for 18 minutes resulting in an RCS heatup of 2 degrees F.

- During a Peach Bottom Unit 3 refueling outage, an unexpected decrease in reactor vessel water level of approximately 42 inches (from +200 inches to +158 inches) occurred over 4.5 minutes. Over 27 feet of water still remained above the top of active fuel. This event occurred during a flush activity of the Unit 3 residual heat removal (RHR) crosstie piping. The procedural controls for the flush activity did not contain instructions to isolate the “B” train of RHR during the flush activity. This resulted in an open flow path from the reactor vessel to the suppression pool. Additionally, shift management did not conduct a pre-job brief with all personnel involved in the flush. This event demonstrated the impact of adverse human performance on shutdown risk controls.

DISCUSSION

Planning, scheduling, and execution of work activities during outages can have a significant impact on overall plant risk. Refueling outages have become shorter, causing higher risk evolutions, such as midloop operations at PWRs, to be entered sooner after reactor shutdown. As a result there is reduced inventory in the reactor vessel at a time when the decay heat loads are high and the time to boil and uncover the core is relatively low. During these high risk evolutions, careful attention to work scheduling is necessary to ensure that decay heat removal cooling systems remain functional.

It is also important that work activities be scheduled to minimize distractions to operators and prevent unnecessary challenges to decay heat removal systems. Licensees need to continue to properly implement commitments made to previous generic communications on shutdown operations. Additionally, licensees need to continue to implement the controls specified by NUMARC 91-06 to properly manage shutdown risk.

CONTACTS

This information notice requires no specific action or written response. Please direct any questions about this matter to the technical contacts listed below or the appropriate Office of Nuclear Reactor Regulation (NRR) project manager.

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Note: NRC generic communications may be found on the NRC public website, http://www.nrc.gov, under Electronic Reading Room/Document Collections.

INCIDENT REPORTING SYSTEM

IRS NO.	EVENT DATE N/A	DATE RECEIVED

EVENT TITLE

NRC Information Notice 2005-20: Electrical Distribution System Failures Affecting Security Equipment

COUNTRY
US

PLANT AND UNIT
Many

REACTOR TYPE
GEN

INITIAL STATUS
N/A

RATED POWER (MWe NET)
N/A

DESIGNER
N/A

1st COMMERCIAL OPERATION
N/A

ABSTRACT

The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to inform addressees about the adverse impact of electrical distribution system failures on security systems.

NRC INFORMATION NOTICE 2005-20

Please refer to the dictionary of codes corresponding to each of the sections below and to the coding guidelines manual.

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1. **Reporting Categories:**
   1.5

2. **Plant Status Prior to the Event:**
   2.0

3. **Failed/Affected Systems:**
   3.EG

4. **Failed/Affected Components:**
   4.3.0
   4.3.7
   4.3.8

5. **Cause of the Event:**
   5.1.2.1
   5.1.2.6

6. **Effects on Operation:**
   6.0

7. **Characteristics of the Incident:**
   7.16

8. **Nature of Failure or Error:**
   8.1

9. **Nature of Recovery Actions:**
   9.3

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555

July 19, 2005

NRC INFORMATION NOTICE 2005-20: ELECTRICAL DISTRIBUTION SYSTEM FAILURES AFFECTING SECURITY EQUIPMENT

ADDRESSEES

All holders of operating licenses for power reactors, except those who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor.

PURPOSE

The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to inform addressees about the adverse impact of electrical distribution system failures on security systems. The NRC anticipates that recipients will review the information for applicability to their facilities and consider taking actions, as appropriate, to avoid similar issues. However, no specific action or written response is required.

DESCRIPTION OF CIRCUMSTANCES

On June 14, 2004, a ground fault occurred on a 230kV transmission line at a location some distance from the Palo Verde Nuclear Generating Station. A failure in the protective relaying prevented the immediate isolation of the ground fault from the local grid and caused a loss of offsite power and reactor trips of all three Palo Verde units. The Unit 2 Train A emergency diesel generator (EDG) started but did not complete the load sequencing process due to a failed diode in the exciter rectifier circuit. As a result the Train A engineered safeguards feature busses deenergized, causing the loss of some security equipment. Other aspects of this event were previously discussed in NRC Information Notice 2005-15, “Three-Unit Trip and Loss of Offsite Power at Palo Verde Nuclear Generating Station,” issued on June 1, 2005.

On June 29, 2004, a complete loss of security power occurred while operators were troubleshooting the security power distribution system at the Watts Bar Nuclear Plant. An operator opened a panel door and removed a subpanel cover to verify the system parameters for an uninterruptible power supply (UPS). The operator then reattached the subpanel cover but did not verify that the latching screw adequately secured the subpanel cover to the outer panel frame. Subsequently, when the operator closed the panel door, the subpanel cover rocked off of the latching mechanism and nicked a ribbon cable, causing a short to ground and the eventual loss of all security power.

ML051920213

On January 14, 2005, water intrusion into the central alarm station (CAS) master electrical distribution panel resulted in arcing in the vicinity of the power supply circuit breaker to the CAS at the Millstone Power Station. The ensuing fire caused a loss of electrical power to multiple security systems. Although the security EDG was available during the event, the electrical fault and fire also prevented the licensee from transferring loads to the EDG.

On February 8, 2005, a short circuit and fire occurred in an outdoor cable tray at the Turkey Point Nuclear Plant, resulting in the loss of some plant security equipment. The fire also resulted in the loss of the normal power supply to a security UPS; however, all security systems powered by the UPS remained energized. On February 17, 2005, a second event occurred at Turkey Point when a component of the security UPS overheated and started a fire. Operators immediately opened circuit breakers at the UPS, causing all security systems serviced by the UPS to be lost.

DISCUSSION

Failures of electrical distribution systems that supply electrical power to plant security systems can cause significant, prolonged outages of equipment normally relied on by security personnel to provide intrusion detection and access control and to respond to security incidents. In all of the events described above, the affected licensees implemented compensatory security measures in response to the security system degradations. Other licensees are reminded to consider these types of failures when developing and reviewing security procedures for responding to degraded equipment.

Licensees are also encouraged to ensure that security equipment undergoes preventive maintenance and is subject to corrective action programs similar to programs for safety-related equipment. In addition, licensees should consider taking actions to identify single points of failure which may not have been recognized in the original design of or modifications to these systems .

CONTACT

This information notice does not require any specific action or written response. Please direct any questions about this matter to the technical contacts listed below or the appropriate Office of Nuclear Reactor Regulation (NRR) project manager.

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Note: NRC generic communications may be found on the NRC public Website, http://www.nrc.gov, under Electronic Reading Room/Document Collections.

INCIDENT REPORTING SYSTEM

IRS NO.	EVENT DATE	N/A	DATE RECEIVED

EVENT TITLE

Information Notice 2005-21: Plant Trip and Loss of Preferred AC Power From Inadequate Switchyard Maintenance

COUNTRY	PLANT AND UNIT	REACTOR TYPE
US	Dresden 2 and 3	BWR
INITIAL STATUS	**RATED POWER (MWe NET)**	
Full Power/Shutdown	809	
DESIGNER	**1st COMMERCIAL OPERATION**	
GE	6/9/1970, 11/16/1971	

ABSTRACT

The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice (IN) to inform addressees about loss of power events as a result of inadequate preventive and corrective maintenance practices on switchyard breakers and current transformers.

NRC INFORMATION NOTICE 2005-21

Please refer to the dictionary of codes corresponding to each of the sections below and to the coding guidelines manual.

---

1. **Reporting Categories:**
   1.3.3

2. **Plant Status Prior to the Event:**
   2.1.1
   2.3

3. **Failed/Affected Systems:**
   3.EA
   3.BG

4. **Failed/Affected Components:**
   4.3.1
   4.3.2

5. **Cause of the Event:**
   5.1.2.9
   5.4.5
   5.4.17

6. **Effects on Operation:**
   6.1.1
   6.0

7. **Characteristics of the Incident:**
   7.9

8. **Nature of Failure or Error:**
   8.1

9. **Nature of Recovery Actions:**
   9.2
   9.3

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555-0001

July 21, 2005

NRC INFORMATION NOTICE 2005-21: PLANT TRIP AND LOSS OF PREFERRED AC POWER FROM INADEQUATE SWITCHYARD MAINTENANCE

ADDRESSEES

All holders of operating licensees for nuclear power reactors, except those who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor vessel.

PURPOSE

The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to inform addressees about loss of power events as a result of inadequate preventive and corrective maintenance practices on switchyard breakers and current transformers. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements; therefore, no specific action or written response is required.

DESCRIPTION OF CIRCUMSTANCES

On May 5, 2004, Dresden Unit 3 was at full power and Dresden Unit 2 was shutdown when an automatic reactor scram and a subsequent loss of offsite power event occurred during activities to reconfigure breakers in the 345 kV switchyard. Operations personnel manually opened switchyard breaker 8-15 in accordance with the switching order. However, when the A and B phases opened, the C phase of switchyard breaker 8-15 failed to fully open within the required time. This failure produced current imbalances in Unit 2 and Unit 3 switchyard ring busses (tied together through a breaker), which led to the opening of several other switchyard breakers. Unit 3 scrammed due to turbine load reject, and offsite power was lost to the Unit 3 safety-related emergency core cooling system (ECCS) busses. The failed breaker was an I-T-E Imperial Corporation (current vendor ABB) sulfur hexafluoride (SF6) gas circuit breaker (type 362GA). This breaker used independent pole operators for each of the three phases. The breaker was built and installed in the Dresden 345 kV switchyard in the late 1970's.

On May 6, 2004, the licensee and personnel of the transmission and distribution company, Exelon Energy Delivery (EED), discovered that ABB, the current breaker vendor, had issued a product advisory in July 2003 for I-T-E Imperial Corporation GA and GB breakers to warn that the operating mechanisms may experience delayed trip or in some cases failures to trip due to age and application related problems. In addition, the advisory noted that the breakers at

ML051740051

highest risk were those operated less than twice per year. The product advisory recommended that the operating mechanism in high-risk applications be rebuilt using new trip latch mechanism kits at the earliest convenience.

While disassembling the trip latch mechanism of Breaker 8-15, EED and licensee personnel discovered that the sealed bearing for the trip latch mechanism did not roll freely. The failure of the sealed bearing to roll freely, directly contributed to the failure of the C phase of Breaker 8-15 to open within the required time. The NRC special inspection team reviewed the maintenance history of Breaker 8-15. The last preventive maintenance on Breaker 8-15 was done on March 27, 2002, and included routine inspection, lubrication and maintenance, a contact resistance test, and a travel timing test. The inspection team noted that the breaker failed the timing test on the C Phase. The breaker was last cycled in October 2002 and then remained in the closed position until May 5, 2004.

The NRC inspection team noted that the EED procedure stated that the breaker should be lubricated after a failed timing test. However, the vendor manual stated that, the operating mechanism should be disassembled and cleaned and lubricated when the operating mechanism showed signs of difficult or sluggish operation. In addition, the manual stated that under ordinary circumstances, the life of the grease in sealed bearings should be at least 10 years and that if oxidation of the lubricant made the bearing sluggish, the bearing must be replaced. The EED preventive maintenance program and procedures for breakers did not include routine replacement of worn out breaker parts. In addition, the EED maintenance procedures did not instruct maintenance personnel to disassemble sluggish operating mechanisms to check for degraded bearings, nor did the procedures specify the appropriate lubricants for the various parts of the breaker.

On June 12, 2002, with DC Cook Unit 1 at approximately 68% power and Unit 2 at 100% power, an emergency alert condition was entered after a catastrophic failure and resultant fire of a current transformer for the 345 kV switchyard L breaker. The catastrophic failure of the current transformer and the subsequent switchyard switching actions resulted in the loss of the preferred offsite power source to Units 1 and 2. On June 19, 2002, the NRC special inspection team reviewed the licensee’s preventive maintenance program for 345 kV switchyard current transformers. The vendor’s preventive maintenance recommendations included annual inspections and transformer oil analysis every 2 years. The inspection team reviewed historical maintenance activities on the L breaker current transformers and determined that preventive maintenance activities were last done in October 1998. The periodicity of preventive maintenance activities was consistent with American Electric Power (AEP) system guidelines, but not with the vendor’s recommendations. Additionally, the licensee did not periodically perform several vendor-recommended tests, including tests of oil dielectric strength and oil acid factor, and a measurement of the resistance of the current transformer primary (to compare with the results in the test report). During followup discussions, licensee personnel stated that the types of testing performed and the testing frequencies were based on AEP system operating experience rather than vendor recommendations. Licensee personnel were unable to readily provide specific operating experience data that justified the 4-year preventive maintenance testing frequency. Licensee personnel subsequently determined that there were approximately one hundred twenty six 345 kV current transformers in the AEP system similar in design to the transformers located in the DC Cook 345 kV switchyard. Since 1990, there have been two catastrophic failures (both associated with the D. C. Cook 345 kV switchyard L breaker). No current transformers of this type had been removed from service based on preventive maintenance testing.

Following the June 12, 2002, current transformer failure, AEP collected oil samples from the D.C. Cook 345 kV switchyard breaker current transformers for analysis. The oil analyses were completed 3 months before the normal schedule as part of the licensee's extent-of-condition evaluation. During the oil sampling, AEP personnel discovered that two current transformers for N1 switchyard breaker were last sampled in September 1998, with gas analyses results significantly above the acceptable level. Based on this result, licensee replaced the N1 breaker current transformers and returned the breaker to service on June 29, 2002. The AEP system operating experience data did not justify a less frequent analysis than recommended by the vendor.

DISCUSSION

The discrepancies, between the licensee's maintenance practices for switchyard breaker and current transformers and the vendor recommendations, contributed to the inadvertent switchyard breaker trips that resulted in a plant trip and loss of offsite power (LOOP) to safety busses. Unnecessary plant trips and LOOP events could be reduced by following vendor recommendations with feedback from operating experience to determine the appropriate schedule and extent of maintenance.

CONTACT

This information notice requires no specific action or written response. Please direct any questions about this matter to the technical contact listed below or the appropriate Office of Nuclear Reactor Regulation (NRR) project manager.

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Note: NRC generic communications may be found on the NRC public Website, http://www.nrc.gov, under Electronic Reading Room/Document Collections.

INCIDENT REPORTING SYSTEM

IRS NO. **EVENT DATE** **N/A** **DATE RECEIVED**

EVENT TITLE

NRC Information Notice 2005-23: Vibration-Induced Degradation of Butterfly Valves Recirculation Pump Shafts

COUNTRY	PLANT AND UNIT	REACTOR TYPE
United States	San Onofre 2	PWR
INITIAL STATUS	**RATED POWER (MWe NET)**	
N/A	1127	
DESIGNER	**1st COMMERCIAL OPERATION**	
Combustion CE	8/8/1983	

ABSTRACT

The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice (IN) to alert addressees to the degradation of butterfly valves supplied by Fisher Controls and other manufacturers.

NRC INFORMATION NOTICE 2005-23

Please refer to the dictionary of codes corresponding to each of the sections below and to the coding guidelines manual.

---

1. **<u>Reporting Categories</u>:**
   1.2.6
   1.4

2. **<u>Plant Status Prior to the Event</u>:**
   2.1.1

3. **<u>Failed/Affected Systems</u>:**
   3.CA

4. **<u>Failed/Affected Components</u>:**
   4.2.3

5. **<u>Cause of the Event</u>:**
   5.1.1.5

6. **<u>Effects on Operation</u>:**
   6.0

7. **<u>Characteristics of the Incident</u>:**
   7.0

8. **<u>Nature of Failure or Error</u>:**
   8.2.3

9. **<u>Nature of Recovery Actions</u>:**
   9.3

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555-0001

August 1, 2005

INFORMATION NOTICE 2005-23: VIBRATION-INDUCED DEGRADATION OF BUTTERFLY VALVES

ADDRESSEES

All holders for operating licenses for nuclear power reactors except those who have permanently ceased operation and have certified that fuel has been permanently removed from the vessel.

PURPOSE

The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to alert addressees to the degradation of butterfly valves supplied by Fisher Controls and other manufacturers. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements; therefore, no specific action or written response is required.

DESCRIPTION OF CIRCUMSTANCES

On February 10, 2005, Southern California Edison declared component cooling water (CCW) outlet isolation valve 2HV6500 for the Train B shutdown cooling (SDC) heat exchanger in Unit 2 at the San Onofre Nuclear Generating Station (SONGS) inoperable in response to an abnormal reduction in flow through the valve. Valve 2HV6500 is an 18-inch butterfly valve manufactured by Fisher Controls. The operability of the containment spray (CS) system at SONGS Unit 2 depends on the availability of the SDC heat exchanger. Therefore, the licensee started a manual shutdown of SONGS Unit 2 on February 14, 2005, to repair the valve.

The licensee disassembled the valve and found that it could not fully open as a result of losing two taper pins that connect the valve disc to the valve stem. During the original installation, the taper pins are impact-driven into holes in the valve disc and stem and are intended to be held in place by the interference fit. The licensee could not determine the exact cause of the loss of the taper pins during plant operation. As corrective action, the licensee installed new taper pins and staked the pins to the valve disc to make them more secure.

ML051740299

Since 1993, five Fisher Controls 28-inch butterfly valves in the CCW systems of SONGS Units 2 and 3 have lost one of the taper pins used to connect the valve disc to the valve stem. The licensee has also found additional Fisher Controls butterfly valves with improperly seated taper pins during internal inspections.

The design of the Fisher Controls butterfly valves can allow leakage through the valve if a taper pin is lost. For example, SONGS experienced leakage rates of approximately 50 gallons per minute (gpm) through 28-inch Fisher Controls butterfly valves in the CCW system in 1998 and 2004. After disassembling the butterfly valves, the licensee identified the cause of the leakage as the loss of a single taper pin in each of the valves.

Taper pins that come loose from butterfly valves can be carried with the system fluid and interfere with the operation of other plant equipment. For example, one of the missing taper pins from 2HV6500 at SONGS Unit 2 became lodged in train “B” CCW pump manual discharge isolation valve 2HCV6509, which is normally locked open and closed only for maintenance purposes. After maintenance on the train “B” CCW pump, the licensee had difficulty opening 2HCV6509 because of the taper pin lodged in the valve.

The licensee plans to review all butterfly valves in safety-related applications where loss of valve function or leakage because of a missing taper pin cannot be tolerated. On the basis of the review, the licensee will determine which butterfly valves to inspect during the upcoming refueling outages at SONGS Units 2 and 3. As part of the valve inspections, the licensee will stake the taper pins in the butterfly valves to ensure the pins remain in place during plant operation.

DISCUSSION

Over the years, nuclear power plants have experienced vibration-induced degradation of plant equipment during operation at the original licensed power and under power uprate conditions. The NRC has issued several information notices on vibration-induced degradation of plant equipment. For example, the NRC issued Information Notice (IN) No. 83-70, “Vibration-Induced Valve Failures,” on October 25, 1983, to alert nuclear power plant licensees to valve failures and system inoperability as a result of normal operational vibration.

The degradation of Fisher Controls butterfly valves as a result of the loss of their taper pins at SONGS Units 2 and 3 is another example of vibration-induced degradation during plant operations. There have also been problems with the taper pins that connect the valve disc to the stem in butterfly valves supplied by other manufacturers. In 1989 Turkey Point Nuclear Plant, Unit 4, lost taper pins in a 36-inch intake cooling water head isolation butterfly valve manufactured by the Henry Pratt Company. In 2003 Davis-Besse Nuclear Power Station, Unit 1, lost taper pins in a 10-inch decay heat cooler butterfly valve with the brand name Valtek marketed by the Flowserve Corporation.

Depending on the valve design, the loss of a taper pin from a butterfly valve may result in significant leakage through the valve before interfering with valve operation. The size of the taper pin and fluid conditions can cause the leakage limits for the applicable plant system to be exceeded. In addition, leakage through a valve can be masked by another closed valve in the system until the second valve is opened.

Taper pins that come loose from butterfly valves can be carried with the system fluid and interfere with the operation of other plant equipment. The example of 2HCV6509 at SONGS Unit 2 had low safety significance because this valve is only used for maintenance at the plant.

Some nuclear power plants have experienced more severe vibration-induced degradation of equipment under power uprate conditions. For example, the NRC staff described vibration-induced degradation of plant equipment during power uprate operation in IN 2002-26, Supplement 2, “Additional Flow-Induced Vibration Failures After a Recent Power Uprate” (January 9, 2004). Increased steam and feedwater flow during power uprate operation can increase vibration of plant equipment, including valves and valve actuators. The higher vibration levels can impact the appropriate inspection intervals for some plant components.

In summary, degradation of butterfly valves supplied by Fisher Controls and other manufacturers has occurred during plant operation as a result of the loss of taper pins used to connect the valve disc to stem. The degradation can involve leakage and affect valve operation. Taper pins lost from butterfly valves can also interfere with the operation of other plant components in fluid systems. The cause of the loss of valve taper pins is not known for certain, but operating experience suggests that the most likely cause is vibration-induced degradation. Staking the taper pins after their installation in the butterfly valves is one method of providing a more secure interference fit of the pins. The increased steam and feedwater flow during power uprate operation can accelerate vibration-induced degradation of plant equipment, including valves and valve actuators.

RELATED GENERIC COMMUNICATIONS

NRC Information Notice 83-70, “Vibration-Induced Valve Failures,” October 25, 1983.

NRC Information Notice 2002-26, Supplement 2, “Additional Flow-Induced Vibration Failures After a Recent Power Uprate,” January 9, 2004.

This information notice requires no specific action or written response. However, recipients are reminded that they are required by 10 CFR 50.65 to consider industry-wide operating experience (including information presented in NRC information notices) where practical, when setting goals and performing periodic evaluations.

CONTACT

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Note: NRC generic communications may be found on the NRC public Website, http://www.nrc.gov, under Electronic Reading Room/Document Collections.