OMB Control No.: 3150-0011

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, DC 20555-0001

January 11, 2008

NRC GENERIC LETTER 2008-01: MANAGING GAS ACCUMULATION IN EMERGENCY CORE COOLING, DECAY HEAT REMOVAL, AND CONTAINMENT SPRAY SYSTEMS

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 generic letter (GL) to address the issue of gas[1] accumulation in the emergency core cooling, decay heat removal (DHR)[2], and containment spray systems (hereinafter referred to as the "subject systems"). Specifically, the NRC is issuing this GL for two purposes:

(1) to request addressees to submit information to demonstrate that the subject systems are in compliance with the current licensing and design bases and applicable regulatory requirements, and that suitable design, operational, and testing control measures are in place for maintaining this compliance

(2) to collect the requested information to determine if additional regulatory action is required

Pursuant to Title 10 Section 50.54(f) of the *Code of Federal Regulations* (10 CFR 50.54(f)), addressees are required to submit a written response to this GL.

ML072910759

[1]"Gas" as used here includes air, nitrogen, hydrogen, water vapor, or any other void that is not filled with liquid water.

[2]DHR, residual heat removal (RHR), and shutdown cooling are common names for systems used to cool the reactor coolant system (RCS) during some phases of shutdown operation. In this GL, the NRC staff generally uses "DHR."

BACKGROUND

Instances of gas accumulation in the subject systems have occurred since the beginning of commercial nuclear power plant operation. The NRC has published 20 information notices (INs), two GLs, and a NUREG[3] related to this issue and has interacted with the nuclear industry many times in relation to these publications and in response to gas accumulation events. The following paragraphs summarize a few events to illustrate some of the technical and regulatory requirements issues.

In May 1997, at Oconee Nuclear Station Unit 3, hydrogen ingestion during plant cooldown damaged and rendered nonfunctional two high-pressure injection (HPI) pumps. If the operators had started the remaining HPI pump, it too would have been damaged. The NRC responded with an augmented inspection team (IN 97-38, "Level-Sensing System Initiates Common-Mode Failure of High-Pressure-Injection Pumps," June 24, 1997, ADAMS Accession No. ML031050514. The NRC team reported that there had been a total lack of HPI capability during power operation, a failure to meet technical specification (TS) HPI operability requirements, design deficiencies, inadequate maintenance practices, operators who were less than attentive to plant parameters, a failure to adequately assess operating experience, and a violation of Criterion III of Appendix B to 10 CFR Part 50. The NRC's followup actions are summarized in "Notice of Violation and Proposed Imposition of Civil Penalties - $330,000," August 27, 1997, http://www.nrc.gov/reading-rm/doc-collections/enforcement/actions/reactors/ea97297.html).

As a result of this Oconee Unit 3 event, the industry initiated an improvement activity to address the gas issue. Based on the anticipated actions, the NRC concluded that no generic action was necessary. However, significant gas events that can adversely impact operability of the subject systems continued to occur, as illustrated in the following paragraphs.

Dresden Nuclear Power Station Unit 3 experienced a reactor scram on July 5, 2001, that was accompanied by a water hammer[4] due to high pressure coolant injection (HPCI) system voids resulting from inadequate pipe venting. The licensee discovered a damaged pipe support that rendered the HPCI system inoperable on July 19, 2001. On September 28, 2001, NRC inspectors discovered discrepancies in another HPCI hanger that may have been caused by the water hammer. The licensee repaired the hangers on September 30, 2001, and vented the system. An NRC inspector identified a high point that had not been vented and air was removed when the licensee vented that location. The HPCI system was inoperable from July 5, 2001, to September 30, 2001 (NRC Supplemental Inspection Report 50-237, 50-239/2003-012, December 18, 2003, ADAMS Accession No. ML033530204). The NRC found violations of 10 CFR 50.9, a TS, and 10 CFR Part 50, Criterion XVI of Appendix B to 10 CFR Part 50 ("Notice of Violation and Proposed Imposition of Civil Penalty - $60,000, and Final

---

[3] GL 88-17, "Loss of Decay Heat Removal," October 17, 1988 (Agencywide Documents Management and Access System (ADAMS) Accession No. ML031200496); GL 97-04, "Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps," October 7, 1997 (ADAMS Accession No. ML031110062); and NUREG-0897, Revision 1, "Containment Emergency Sump Performance—Technical Findings Related to USI A-43," October 1985.

[4] "Water hammer" refers to any transient pressure condition that is caused by or exacerbated by the presence of a void in a system regardless of whether the pressure condition was benign or resulted in damage.

Significance Determination for a White Finding," June 23, 2003, ADAMS Accession No. ML031740755).

On June 4, 2003, Quad Cities operators performed a monthly TS surveillance to demonstrate that the 1B core spray pump discharge piping was full of water. The piping was vented for 12 minutes before water flow was observed and the NRC inspectors determined that the licensee had failed to provide a correct venting procedure that would ensure continued pump operability. The system engineer estimated that the piping was about one-half empty. A water hammer with the potential to cause damage would have occurred if the core spray pump had been started and the core spray system was determined to be inoperable in the as-found condition. The NRC inspectors also determined that the emergency core cooling system (ECCS) surveillance procedures were incorrect, that licensee review in response to the excess gas was inadequate, and that TS 3.0.4 had been violated. This was considered to be a licensee-identified violation, the finding was greater than minor because of the pump inoperability, and the finding was considered to be of very low safety significance because it did not result in an actual loss of function. It was dispositioned as a noncited violation and entered into the corrective action program (NRC Inspection Report 50-254/03-05, 50-265/03-05, July 17, 2003, ADAMS Accession No. ML031980621).

On August 14, 2003, the Perry Nuclear Power Plant scrammed from 100 percent power because of a loss of offsite power. This caused a momentary loss of common water leg pumps[5] and a discharge pressure decrease from 44 psig to 7 psig allowed accumulated gas to completely void a water leg pump and the associated feedwater leakage control system piping. Pump operation was restored by venting the pump casing but a piping high point that was not included in fill and vent procedures was not vented. On September 10, 2003, the licensee vented enough gas from the high point that would have caused the pump to be non-functional if another loss of offsite power had occurred. If the RHR and/or the low-pressure core spray pumps had started while the leakage control system piping was voided, the resulting water hammer could have caused the system piping to rupture. The NRC characterized the inspection finding as white; the finding resulted in a TS violation, escalated enforcement action, and a supplemental inspection (NRC Inspection Report 50-440/2003-009, October 10, 2003, ADAMS Accession No. ML032880107, and January 30, 2004, ADAMS Accession No. ML040330980).

On July 28, 2004, the Palo Verde licensee identified that ECCS suction piping voids in all three Palo Verde units could have resulted in a loss of the ECCS during transfer to the recirculation mode for some loss-of-coolant accident (LOCA) conditions. The condition had existed since plant startups in 1986, was contrary to the Palo Verde final safety analysis reports (FSARs), and would not be identified during testing because water is not drawn from the containment emergency sumps. The NRC inspectors identified multiple violations of Criteria III and V in Appendix B to 10 CFR Part 50 and violations of 10 CFR 50.59. The NRC responded with a special inspection, issued a yellow finding, and imposed a civil penalty of $50,000 (NRC Special Inspection Report 50-328, 50-329, 50-330/2004-014, January 5, 2005, ADAMS Accession No.

---

[5]These are 40 gallon per minute (gpm) pumps used to compensate for back-leakage through check valves in RHR and low-pressure core spray piping into the suppression pool. Their purpose is to keep piping full of water where the pipe elevation is higher than the suppression pool. The system is often referred to as a "keep-full" system.

ML050050287). The Palo Verde licensee identified the ECCS piping suction voids after being contacted by an engineer from another plant where an NRC inspector had identified the same problem.

In February 2005, an HPI pump at Indian Point Energy Center Unit 2 was found inoperable because the pump casing was filled with gas. The licensee then found several locations in the ECCS piping with gas accumulation. The licensee did not initially understand the implications of the gas condition, and the licensee's early assessments were inadequate, particularly with respect to assessing the operability of the other two HPI pumps. The NRC conducted a special inspection that found one HPI pump was not functional and the other two HPI pumps had a 75 percent failure probability. The NRC found several violations of Criterion XVI of Appendix B to 10 CFR Part 50 and issued a white finding (NRC Inspection Report 50-247/2005-006, June 17, 2005, ADAMS Accession No. ML051680119).

In March 2005, the NRC reported that Diablo Canyon had a sustained history of gas voiding in piping that could possibly result in gas binding or damage to the centrifugal charging pumps or the high pressure safety injection (HPSI) pumps during switchover from cold-leg to hot-leg injection.[6] The inspection report listed 10 recent gas voiding occurrences and the NRC inspectors concluded that the licensee focused on managing the symptom of the problem rather than finding and eliminating the cause, which is contrary to Criterion XVI of Appendix B to 10 CFR Part 50. The finding was more than minor in that the voiding could have caused mitigating equipment to fail but was of very low safety significance because the inspectors concluded that there was no loss of function. This was a noncited Violation (NRC Inspection Report 50-275, 50-323/2005-006, March 31, 2005, ADAMS Accession No. ML050910120).

In September 2005, a void was discovered in the HPCI pump discharge piping at the Duane Arnold Energy Center resulting from "turbulent penetration" that caused hot water from the feedwater pipe to penetrate downward into the HPCI discharge pipe. This heated the HPCI pipe on the low pressure side of a closed valve to greater than the saturation temperature and caused steam to be generated in the low pressure pipe as fast as it was vented. The condition had existed since plant startup (Licensee Event Report 50-331/2005-004, November 28, 2005, ADAMS Accession No. ML053360261). The NRC opened an unresolved item (URI 05000331/2006002-03) for further NRC review of the licensee's piping analysis that evaluated HPCI system operability with the voided piping. NRC determined the condition to be adverse to quality since it was not identified by the licensee, was uncorrected, and was a violation of Criterion XVI to Appendix B of 10 CFR Part 50. The issue was found to be of very low safety significance and entered into the corrective action program. The violation was treated as a noncited Violation. (NRC Inspection Report 50-331/2006-002, April 27, 2006, ADAMS Accession No. ML061210448, and NRC Inspection Report 50-331/2006-008, March 2, 2007, ADAMS Accession No. ML070640515).

In October 2005, an NRC inspection team at the Palo Verde Nuclear Generating Station identified that, following a postulated accident when refueling water tank (RWT) level reached

[6] A similar gas accumulation problem under closed valves in the recirculation piping from the DHR discharge to the HPSI and charging pump suctions has occurred at several plants. This has the potential to cause loss of all high pressure RCS makeup capability when shifting suction to the emergency containment sump from the refueling water or borated water storage tank following a LOCA.

the setpoint for containment sump recirculation, the licensee's design basis credited containment pressure for preventing the ECCS pumps from continuing to reduce RWT level and drawing air into the ECCS. However, a recent licensee analysis showed that the minimum containment pressure would be less than needed. The licensee declared the ECCS inoperable at all three units, requiring a shutdown of Units 2 and 3 (Unit 1 was already shut down). The NRC found multiple violations of Criteria III and V of Appendix B to 10 CFR Part 50 (NRC Supplemental Inspection Report 50-528, 50-529, 50-530/2005-012, January 27, 2006, ADAMS Accession No. ML060300193).

These are a few of the more than 60 gas accumulation events reported since the 1997 Oconee Unit 3 event. The NRC staff has assessed these and other events and has concluded that there is reasonable assurance that plants can continue to operate safely while this GL is addressed.

APPLICABLE REGULATORY REQUIREMENTS

The regulations in Appendix A to 10 CFR Part 50 or similar plant-specific principal design criteria[7] provide design requirements, and Appendix B to 10 CFR Part 50, TSs, and licensee quality assurance programs provide operating requirements. Appendix A requirements applicable to gas management in the subject systems include the following:

- General Design Criterion (GDC) 1 requires that the subject systems be designed, fabricated, erected, and tested to quality standards.
- GDC 34 requires an RHR system designed to maintain specified acceptable fuel design limits and to meet design conditions that are not exceeded if a single failure occurs and specified electrical power systems fail.
- GDC 35, 36, and 37 require an ECCS design that meets performance, inspection, and testing requirements. The regulations in 10 CFR 50.46 provide specified performance criteria.
- GDC 38, 39, and 40 require a containment heat removal system design that meets performance, inspection, and testing requirements.

Quality assurance criteria provided in Appendix B that apply to gas management in the subject systems include the following:

- Criteria III and V require measures to ensure that applicable regulatory requirements and the design basis, as defined in 10 CFR 50.2, "Definitions," and as specified in the license application, are correctly translated into controlled specifications, drawings, procedures, and instructions.

[7]These apply to facilities with a construction permit issued before May 21, 1972, that are not licensed under Appendix A.

- Criterion XI requires a test program to ensure that the subject systems will perform satisfactorily in service. Test results shall be documented and evaluated to ensure that test requirements have been satisfied.

- Criterion XVI requires measures to ensure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances, are promptly identified and corrected, and that significant conditions adverse to quality are documented and reported to management.

- Criterion XVII requires maintenance of records of activities affecting quality.

Furthermore, as part of the licensing basis, licensees have committed to certain quality assurance provisions that are identified in both their TSs and quality assurance programs. Licensees have committed to use the guidance of Regulatory Guide (RG) 1.33, "Quality Assurance Requirements (Operation)," revision 2, issued February 1978, which endorses American National Standards Institute (ANSI) N18.7-1976/American Nuclear Society 3.2, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants," or equivalent licensee-specific guidance. Section 5.3.4.4, "Process Monitoring Procedures," of ANSI N18.7 states that procedures for monitoring performance of plant systems shall be required to ensure that engineered safety features and emergency equipment are in a state of readiness to maintain the plant in a safe condition if needed. The limits (maximum and minimum) for significant process parameters shall be identified. Operating procedures shall address the nature and frequency of this monitoring, as appropriate.

In 10 CFR 50.36(c)(3), the NRC defines TS surveillance requirements (SRs) as "relating to test, calibration, or inspection to assure" maintenance of quality, operation within safety limits, and operability. Typically, TS Section 5 or 6 requires that licensees establish, implement, and maintain written procedures covering the applicable procedures recommended in Appendix A to RG 1.33. Appendix A to RG 1.33 identifies instructions for filling and venting the ECCS and DHR system, as well as for draining and refilling heat exchangers. Standard TSs and most licensee TSs provide SRs to verify that at least some of the subject systems piping is filled with water.

DISCUSSION

The events discussed in the Background section illustrate that the licensee was not meeting some of the regulatory requirements identified in the Applicable Regulatory Requirements section. The operating license and regulations require adequate design, tests, procedures, records, and corrective actions, whereas operating experience and NRC inspections have revealed inadequate designs, test programs, procedures, test result documentation, and corrective actions at licensed facilities. This GL requests licensees to provide information on methods used to comply with these NRC requirements. The NRC will evaluate this information to determine if further regulatory action is necessary to ensure compliance.

It is important that the subject systems are sufficiently filled with water to ensure that they can reliably perform their intended functions under all LOCA and non-LOCA conditions that require makeup to the RCS. Portions of these systems and some of the associated pumps are normally in a standby condition while other pumps provide both ECCS and operational functions. For example, some high-pressure pumps are used for normal RCS makeup, and some low-pressure pumps provide a normal DHR capability.

The following six examples illustrate how inadequate gas control can have safety implications:

(1) The introduction of gas into a pump can cause the pump to become air bound with little or no flow, rendering the pump inoperable. Air binding can render more than one pump inoperable when pumps share common discharge or suction headers, or when the gas accumulation process affects more than one train, greatly increasing the risk significance. Such a common-mode failure would result in the inability of the ECCS or the DHR system to provide adequate core cooling and the inability of the containment spray system to maintain the containment pressure and temperature below design limits. An air-bound pump can become damaged quickly, eliminating the possibility of recovering the pump during an event by subsequently venting the pump and suction piping.

(2) Gas introduced into a pump can render the pump inoperable, even if the gas does not air bind the pump, because the gas can reduce the pump discharge pressure and flow capacity to the point that the pump cannot perform its design function. For example, an HPI pump that is pumping air-entrained water may not develop sufficient discharge pressure to inject under certain small-break LOCA scenarios.

(3) Gas accumulation can result in water hammer or a system pressure transient, particularly in pump discharge piping following a pump start, which can cause piping and component damage or failure. Gas accumulation in the DHR system has resulted in pressure transients that have caused DHR system relief valves to open. In some plants, the relief valve reseating pressure is less than the existing RCS pressure, a condition that complicates recovery. This was encountered, for example, during an event at Sequoyah where a pressure pulse resulting from gas in RHR discharge piping caused a relief valve to open and rendered both RHR trains inoperable for 6 hours because the relief valve failed to reseat.

(4) Unbalanced loads caused by entrained gas and the reduction in inlet pressure at a pump because of gas in a vertical suction line that causes pump cavitation can result in additional stresses that lead to premature failure of pump components.

(5) Gas accumulation can result in pumping noncondensible gas into the reactor vessel that may affect core cooling flow.

(6) The time needed to fill voided discharge piping can delay delivery of water beyond the timeframe assumed in the accident analysis.

The number of identified gas accumulation problems and their significance at some facilities raise concerns about whether similar unrecognized design, configuration, and operability problems exist at other facilities.

A review of the operating experience has identified the following four principal concerns, which are the focus of this GL:

(1) **Licensing Basis.** The FSARs at many facilities state that the subject systems are full of water and TSs often require periodic surveillances to confirm this condition. Some plant TSs have incomplete SRs that cover only portions of the system. For example, the TSs may require verifying that ECCS discharge piping is full of water but may not include verification of the suction piping or containment spray piping despite the realistic concern that gas accumulation in suction piping may be more serious than gas accumulation in discharge piping. In addition, since the subject systems could be rendered inoperable or degraded by gas accumulation in any section of piping, the regulations require assessment of gas accumulation to establish operability. Some level of gas accumulation may not affect operability and, where justified, some portions of these systems may be excluded from testing.

(2) **Design.** Criterion III of Appendix B to 10 CFR Part 50 and the operating license identify regulatory requirements for the design of the subject systems. The failure to translate the design basis, such as the system maintained full of water, into drawings, specifications, procedures, and instructions would be contrary to Criterion III of Appendix B to 10 CFR Part 50. Subject system designs vary widely regarding potential gas sources and capability to control gas. Potential gas sources and symptoms of gas leakage from these sources should be identified and potential gas accumulation locations should be known and provisions made to address gas accumulation at these locations. The NRC staff has observed high-point vents that were not located at actual high points, non-existent vents where drawings showed vents, and failure to provide vents or methods for controlling gas at high points. The NRC staff also notes that drawings and isometric diagrams often show piping as level whereas as-installed piping is sloped.

(3) **Testing.** Criteria V and XI of Appendix B to 10 CFR Part 50 and the operating license require licensees to perform testing using written test procedures that incorporate the requirements and acceptance limits contained in applicable design and licensing documents and Criterion XVII requires appropriate records. Testing of portions of piping and components in the subject systems where unacceptable gas accumulation may occur is necessary to confirm acceptance limits and operability unless it has been acceptability established that some portions may be excluded. Surveillance and testing that do not ensure operability prior to the next surveillance are not consistent with this testing requirement.

(4) **Corrective Actions.** Some licensees have treated the accumulation of substantial gas quantities as an expected condition rather than a nonconforming condition and have not documented the condition even when it involved a substantial volume of gas that clearly constituted a significant condition adverse to quality. In such cases, Criterion XVI of Appendix B to 10 CFR Part 50 requires determining the cause of the condition and taking corrective action to preclude repetition.

The enclosure to this GL, "Technical Considerations for Reasonably Assuring Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems Operability," provides additional information. Addressees should consider this information when preparing responses to this GL. Furthermore, the NRC staff plans to use this information during activities that are being planned as a followup to this GL and for guidance in the Technical Specifications Task Force program to develop improved TSs.

REQUESTED ACTIONS

The NRC requests that each addressee evaluate its ECCS, DHR system, and containment spray system licensing basis, design, testing, and corrective actions to ensure that gas accumulation is maintained less than the amount that challenges operability of these systems, and that appropriate action is taken when conditions adverse to quality are identified.

REQUESTED INFORMATION

The NRC requests that each addressee provide the following information: (a) A description of the results of evaluations that were performed pursuant to the above requested actions. This description should provide sufficient information to demonstrate that you are or will be in compliance with the quality assurance criteria in Sections III, V, XI, XVI, and XVII of Appendix B to 10 CFR Part 50 and the licensing basis and operating license as those requirements apply to the subject systems; (b) A description of all corrective actions, including plant, programmatic, procedure, and licensing basis modifications that you determined were necessary to assure compliance with these regulations; and, (c) A statement regarding which corrective actions were completed, the schedule for completing the remaining corrective actions, and the basis for that schedule.

REQUIRED RESPONSE

In accordance with 10 CFR 50.54(f), an addressee must respond as described below.

Within 9 months of the date of this GL, each addressee is requested to submit a written response consistent with the requested actions and information. If an addressee cannot meet the requested response date, the addressee shall provide a response within 3 months of the date of this GL and is requested to describe the alternative course of action that it proposes to take, including the basis for the acceptability of the proposed alternative course of action.

The required written response should be addressed to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, 11555 Rockville Pike, Rockville, MD 20852, under oath or affirmation under the provisions of Section 182a of the Atomic Energy Act of 1954, as amended, and 10 CFR 50.54(f). In addition, addressees should submit a copy of the response to the appropriate regional administrator.

REASONS FOR INFORMATION REQUEST

The NRC is requesting this information because a review of operating experience and NRC inspection results shows recent instances of gas accumulation events involving the subject systems that have rendered or potentially rendered these risk-significant systems inoperable.

RELATED GENERIC COMMUNICATIONS

Document Number	Document Name	ADAMS Accession No.
GL 88-17	Loss of Decay Heat Removal	ML031200496
GL 97-04	Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps	ML031110062
IN 86-63	Loss of Safety Injection Capability	ML031250058
IN 86-80	Unit Startup with Degraded High Pressure Safety Injection System	ML031250214
IN 87-63	Inadequate Net Positive Suction Head in Low Pressure Safety Systems	ML031180034
IN 88-23 IN 88-23, Supp. 1 IN 88-23, Supp. 2 IN 88-23, Supp. 3 IN 88-23, Supp. 4	Potential for Gas Binding of High-Pressure Safety Injection Pumps During a Loss-of-Coolant Accident	ML031150208 ML881230018 ML900125002 ML901204023 ML921215001
IN 88-74	Potentially Inadequate Performance of ECCS in PWRs during Recirculation Operation Following a LOCA	ML031150118
IN 89-67	Loss of Residual Heat Removal Caused by Accumulator Nitrogen Injection	ML031180745
IN 89-80	Potential for Water Hammer, Thermal Stratification, and Steam Binding in High-Pressure Coolant Injection Piping	ML031190089
IN 90-64	Potential for Common-Mode Failure of High Pressure Safety Injection Pumps or Release of Reactor Coolant Outside Containment During a Loss-of-Coolant Accident	ML031103251
IN 91-50	A Review of Water Hammer Events after 1985	ML031190397
IN 94-36	Undetected Accumulation of Gas in Reactor System	ML031060539
IN 94-76	Recent Failures of Charging/Safety Injection Pump Shafts	ML031060430

Document Number	Document Name	ADAMS Accession No.
IN 95-03	Loss of Reactor Coolant Inventory and Potential Loss of Emergency Mitigation Functions While in a Shutdown Condition	ML031060404
IN 96-55	Inadequate Net Positive Suction Head of Emergency Core Cooling and Containment Heat Removal Pumps under Design Basis Accident Conditions	ML031050598
IN 96-65	Undetected Accumulation of Gas in Reactor Coolant System and Inaccurate Reactor Water Level Indication During Shutdown	ML031050500
IN 97-38	Level-Sensing System Initiates Common-Mode Failure of High Pressure Injection Pumps	ML031050514
IN 97-40	Potential Nitrogen Accumulation Resulting from Back-Leakage from Safety Injection Tanks	ML031050497
IN 98-40	Design Deficiencies Can Lead to Reduced ECCS Pump Net Positive Suction Head During Design-Basis Accidents	ML031040547
IN 02-15 IN 02-15 Supp. 1	Potential Hydrogen Combustion Events in BWR Piping	ML020980466 ML031210054
IN 02-18	Effect of Adding Gas Into Water Storage Tanks on the Net Positive Suction Head for Pumps	ML021570158
IN 06-21	Operating Experience Regarding Entrainment of Air Into Emergency Core Cooling and Containment Spray Systems	ML062570468

BACKFIT DISCUSSION

Under the provisions of Section 182a of the Atomic Energy Act of 1954, as amended, this GL requests a review and appropriate resulting actions for the purpose of ensuring compliance with applicable existing requirements. No backfit is either intended or approved by the issuance of this GL. Therefore, the NRC staff has not performed a backfit analysis.

***FEDERAL REGISTER* NOTIFICATION**

A notice of opportunity for public comment on this GL was published in the *Federal Register* (72 FR 29010) on May 23, 2007. The NRC received seven sets of comments, all from the nuclear industry. The NRC staff considered all comments that were received. The NRC staff's evaluation of the comments is publicly available through the NRC's ADAMS under Accession No. ML072410212.

CONGRESSIONAL REVIEW ACT

The NRC has determined that this action is not subject to the Congressional Review Act.

PAPERWORK REDUCTION ACT STATEMENT

This GL contains an information collection that is subject to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*). The Office of Management and Budget approved this information collection under clearance number 3150-0011 which expires on June 30, 2010.

The burden to the public for this mandatory information collection is estimated to average 300 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the information collection.

Send comments on any aspect of this information collection, including suggestions for reducing the burden, to the Records and FOIA/Privacy Services Branch (T5-F52), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, or by Internet electronic mail to infocollects@nrc.gov; and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB-10202 (3150-0011), Office of Management and Budget, Washington, DC 20503.

Public Protection Notification

The NRC may not conduct or sponsor, and a person is not required to respond to, a request for information or an information collection requirement unless the requesting document displays a currently valid OMB control number.

CONTACT

Please direct any questions about this matter to the technical contact or the Lead Project Manager listed below, or to the appropriate Office of Nuclear Reactor Regulation (NRR) project manager.

/RA by TQuay for/

Michael J. Case, Director
Division of Policy and Rulemaking
Office of Nuclear Reactor Regulation

Technical Contact: Warren C. Lyon, NRR/DSS
301-415-2897

Lead Project Manager: David P. Beaulieu, NRR/DPR
301-415-3243

Enclosure:

“Technical Considerations for Reasonably Assuring Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems Operability”

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

CONTACT

Please direct any questions about this matter to the technical contact or the Lead Project Manager listed below, or to the appropriate Office of Nuclear Reactor Regulation (NRR) project manager.

/RA by TQuay for/

Michael J. Case, Director
Division of Policy and Rulemaking
Office of Nuclear Reactor Regulation

Technical Contact: Warren C. Lyon, NRR/DSS
301-415-2897

Lead Project Manager: David P. Beaulieu, NRR/DPR
301-415-3243

Enclosure:

"Technical Considerations for Reasonably Assuring Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems Operability"

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

DISTRIBUTION: GL File

ADAMS ACCESSION NUMBER: ML072910759 * concurred via email

OFFICE	SRXB:DSS	TECH EDITOR	PGCB:DPR	BC:SRXB:DSS	DD:DSS
NAME	WLyon	LCulp*	DBeaulieu	GCranston	JWermiel
DATE	12/03/2007	10/24/2007	11/2/2007	11/09/2007	12/03/2007
OFFICE	D:DSS	BC:DIRS:IOEB	BC:CPTB:DCI	BC:DIRS:ITSB	D:DORL
NAME	WRuland	MRoss-Lee	JMcHale	TKobetz	CHaney (TMcGinty for)
DATE	11/08/2007	10/25/2007	10/24/2007	11/09/2007	10/23/2007
OFFICE	OE	OGC (NLO)	OGC (SBREFA)	OIS	PMDA
NAME	NHilton (RStarkey for)	EWilliamson	TRothschild	MJanney (CColburn for)	LHill
DATE	10/18/2007	11/02/2007	10/15/2007	10/25/2007	10/16/2007
OFFICE	D:RES:DRA	LA:PGCB:DPR	PGCB:DPR	BC:PGCB:DPR	D:DPR
NAME	CLui*	CHawes	AMarkley *	MMurphy	TQuay for MCase
DATE	10/24/2007	11/15/2007	11/29/2007	12/03/2007	12/03/2007

OFFICIAL RECORD COPY

Technical Considerations for Reasonably Assuring Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems Operability

Overview

This enclosure provides a discussion of some of the technical issues that should be considered when evaluating the design, operability, testing, and corrective actions for gas accumulation concerns in emergency core cooling, decay heat removal (DHR), and containment spray systems.

Gas accumulation in the subject nuclear power plant systems can cause water hammer, gas binding in pumps, and inadvertent relief valve actuation that may damage pumps, valves, piping, and supports and may lead to loss of system operability. Consequently, these systems are equipped with vents, and some of the subject systems have keep-full systems that are intended to avoid these problems by maintaining them full of water. However, as summarized in this generic letter (GL), history has shown that the subject systems, as designed and maintained, have been exposed to gas accumulations sufficient to cause potential and actual loss of operability. This enclosure provides insights that addressees should consider when responding to the GL.

The root causes of gas accumulation include poor designs that allow gas introduction and accumulation, licensees failing to properly fill and vent the system following drain-down or maintenance, ineffective controls on gas accumulation during operation, inappropriate technical specifications (TSs), and, in some cases, unanticipated problems with keep-full systems.

The correct objective of gas control measures is to limit the volume of gas accumulation to a quantity that does not jeopardize system operability. An acceptable volume depends on a variety of factors including, but not necessarily limited to, the location, the type of pump, the net positive suction head (NPSH) margin, the gas volume fraction at the pump impeller, and the flow rate. A gas volume downstream of an emergency core cooling system (ECCS) pump that would not cause a loss of system function might cause a pump failure if located upstream of the pump.

The amount and location of gas are important in addressing system operability. Additional work is necessary to develop realistic criteria to determine the amount of gas that could impact operability including the following:

- characterizations of the sources and rate of generation of gases in systems
- ingestion of gas from tanks and recirculation sumps[8] (vortexing)

[8]This includes potential gas accumulation downstream of containment emergency sump screens and post-accumulation transport.

- characterization of gas transport in the subject system piping as a function of system flow requirements

- allowable limits on ingested gas volume in pump suction piping to ensure pump operability, as well as for the pump discharge piping to alleviate water hammer concerns such as slamming check valves or a water cannon effect on the piping

- allowable limits on ingested gas volume to mitigate dynamic pressure pulsation

- development of guidance on the sequence of venting to prevent void formation in high points remote from the vent location

- identification of those portions of systems in which venting is unnecessary such as downstream of the containment spray isolation valve to the spray headers

- evaluation of gas detection techniques and the associated accuracies

This GL enclosure addresses the following six topics:

(1) sources of gas
(2) gas accumulation locations
(3) determination of gas quantity
(4) water hammer and acceptable gas quantity
(5) pump operation and acceptable gas quantity
(6) control of gas

(1) <u>Sources of Gas</u>

Some sources of gas include the following:

- leakage from accumulators

- leakage from the reactor coolant system (RCS)

- outgassing of dissolved gas because of a pressure reduction such as through control valves, orifices, and emergency sump screens, or because of elevation changes or venting

- draining, system realignments, incorrect maintenance procedures, and failure to follow procedures

- failure of level instruments to indicate correct level

- leakage through test header valves

- leakage through faulty vent system components when local pressure is less than the nominal downstream pressure

- temperatures at or above saturation temperature

- vortexing in suction sources or gas introduced from suction sources

Gas in discharge piping can be an indicator of potential backleakage from high-pressure sources such as accumulators or the RCS, and the gas may have moved into the pumps and the pump suction piping. Such gas may have flowed through multiple closed in-series valves. For this reason, it is important to reassess gas accumulation conditions following system operations and valve manipulations. In addition, many plants have a dozen or more test valves that connect to a common header and provide multiple potential leak paths. For example, the gas accumulation rates at the Sequoyah Nuclear Plant were significantly reduced in 2002 by test header valve maintenance and, at Indian Point Energy Center Unit 2, the test header provided a leakage pathway through multiple closed valves into both high-pressure injection (HPI) lines in January 2005.

Some pressurized-water reactors (PWRs) have experienced gas accumulation due to outgassing in charging pump bypass orifices. Installing multiple-stage orifices essentially eliminated the problem by reducing the pressure drop at each orifice to reduce or eliminate non-equilibrium conditions that caused local gas generation.

(2) Gas Accumulation Locations

Some locations where gas can accumulate include the following:

- in high points in pipe runs, including elevation variation in nominally horizontal pipes

- under closed valves

- in DHR[9] system heat exchanger U-tubes

- in horizontal pipe diameter transitions that introduce traps at the top of the larger pipe

- in tees where gas in flowing water can pass into a stagnant pipe where it accumulates

- in valve bonnets

- in pump casings

- in piping when the temperature is at or above the saturation temperature

Some locations, such as tees, horizontal pipes, and valve bonnets, are commonly overlooked. Gas accumulation resulting from the separation of liquid and gas at a tee has caused significant problems. In some PWRs, gas accumulates under the isolation valve in the crossover piping between the DHR pump discharge to the suction of the HPI pumps where there are no vents.

---

[9]DHR, residual heat removal, and shutdown cooling are common names for systems used to cool the reactor coolant system (RCS) during some phases of shutdown operation.

The crossover piping is especially vulnerable because system testing usually does not involve flow through that location and licensees may not have correctly determined the acceptable gas volume. Furthermore, some TS surveillance requirements (SRs) do not specify suction piping. Often, licensees consider the crossover piping as suction piping that does not have to be checked for gas.

Gas accumulation can be exacerbated by failure to adequately determine actual system high points and failure to have vents where gas accumulates. For example, plant isometric drawings sometimes indicate that a length of pipe is horizontal, but an in-plant examination may reveal that the pipe is sloped, sometimes by several inches. This is an important consideration for vent locations and for using ultrasonic testing (UT) to determine gas volume.

(3) <u>Determination of Gas Quantity</u>

Some common methods to determine gas quantity in the subject systems are to measure the volume of gas released through vents or to determine the gas volume by UT.

Some hard-piped vents exhaust at a remote location or into a vent manifold where it is difficult to determine whether any gas was released. Closed systems may have sight glasses for observing bubbles. When the flow rate is adequate to force the gas from the high point down through the vent line to a clean sight glass, and the venting period is long enough for the gas to have traveled through the sight glass, personnel can tell if all gas has been removed. However, it is difficult to accurately determine the volume of gas removed. In some cases, vent flow is passed into a test header with a flow meter, but the accuracy of this method of determining gas quantity is difficult to establish. Vents consisting of a valve with a removable blind flange immediately downstream of the valve allow the effluent to be observed and are often used in conjunction with other means to determine the vented volume. Procedures should cover venting and post-venting actions such as recording observations and/or gas volumes and should ensure a followup if specified criteria related to the gas volume are not met.

Several conditions may effect the accuracy of a vented volume determination. In some locations, venting changes the pressure, and a volume estimate based on venting time may therefore be in error because the venting rate is not constant. In some cases, opening and closing or repositioning the throttle valve during venting may affect timing. Gas and water vapor released from the liquid during depressurization may also affect volume determinations. Saturated water vapor will superheat when pressure decreases and will condense if exposed to a temperature below the saturation temperature. Saturated water may boil during venting when pressure is decreased. These conditions may result in a misleading assessment of gas quantity if the behavior is not recognized.

Other methods of determining gas volume are available. UT can provide accurate gas volumes regardless of vent locations. A known volume of water can be injected into an isolated section of piping (or a heat exchanger) and the void can then be calculated from the known pressures and injected volume. Another method is to record DHR system flow rate behavior immediately following pump start to estimate gas volume in the DHR system discharge piping. NRC Special Inspection Report 50-400/02-06 stated that this method is useful in determining whether the DHR heat exchangers are void free. This was used at Sequoyah where, when a DHR pump was started for testing with the DHR system configured for injection into the RCS, the flow rate indicated on a local gauge immediately downstream of the DHR pump should increase approximately linearly for the first 8 seconds as the minimum flow line flow control valve opens and should then level off at approximately 550 gallons per minute (gpm) if there is no gas volume downstream of the pump. In this case, there would be no actual injection since the RCS pressure was higher than the DHR system pump discharge pressure and the flow was through the minimum flow line. With gas present, the flow rate would increase more rapidly to a value greater than approximately 550 gpm and then decrease to approximately 550 gpm within roughly 20 seconds.

The accuracy necessary for void determination is also of interest. An approximate void determination method will be adequate when the anticipated void is significantly removed from an operability concern based on the historical record and, in that case, recording a parameter that is indicative of the void quantity would be sufficient. Anticipation of more significant voids, sudden increases in void accumulation rate, or observation of other plant behavior such as decreasing accumulator level may require more accurate means to obtain the void size and/or a reduction in time between surveillances[10].

With respect to accuracy, UT can provide a quantitative datum that, when considered in combination with temperature and pressure within a pipe, will yield an accurate void volume. Use of vent valves to obtain a pre-test void volume is more difficult and is often more qualitative. Time to vent to obtain a clear liquid stream, with an acceptance criterion conservatively determined from a correlation of vent time to an acceptable volume for each vent location, may be adequate for trending purposes when anticipated vented volumes are clearly well removed from a region of concern. Volumes that are close to impacting operability may require more sophisticated measurement and may indicate that corrective action is necessary to reduce the gas accumulation rate.

(4) Water Hammer and Acceptable Gas Quantity

A principal water-hammer concern is the sudden pressure increase in the pump discharge piping and associated components when systems are put into service. Another concern is pressurization of the DHR system when it is initially connected to the RCS when the RCS pressure is near the DHR system relief valve set pressure. A small pressure perturbation because of a minor water hammer can open DHR system relief valves, which then might fail to close. The relief valve reseating pressure could be less than the RCS pressure, which complicates recovery. Therefore, it is particularly important to initiate DHR system operation by a process that minimizes the potential to cause a pressure pulse. However, application of such techniques must be carefully considered if used for performing surveillances to assess operability. During testing, any proceduralized deviation from normal system operation must be evaluated for the potential to cause unacceptable preconditioning. If the ECCS must start and operate under accident conditions without benefit of pressure-pulse-reducing techniques, then it should be tested in a manner that demonstrates it is capable of doing so without those techniques.

[10]Item (6) discusses the variation of time between surveillances.

(5) Pump Operation and Acceptable Gas Quantity

The amount of gas that can be ingested without a significant impact on pump operability and reliability is not well established. It is known to depend on pump design, gas dispersion, and flow rate. The presence of gas is undesirable because gas may initiate a long-term failure mechanism such as shaft fatigue, wear ring degradation, bearing wear, or seal wear. Unfortunately, a no-gas condition during initial pump operation or following alignment changes often cannot be ensured in practice, and the operational goal should be to minimize the amount of gas consistent with the requirement that operability must be reasonably assured.

A single-stage pump, such as a DHR system pump with significant clearances between moving parts, can often withstand a large slug of gas that completely stops flow, and the pump may be restored to operation when the gas is removed. However, in some cases, physical pump failure has occurred after ingesting gas. A similar no-flow or reduced-flow condition with a multistage pump that has close tolerances between moving parts, such as the multi-stage pumps used in the ECCS, will likely cause permanent damage.

All pumps will exhibit a loss of developed head when exposed to gas at the pump impeller. The following general conclusions appear reasonable for single-stage pumps that are operating at close to rated flow rate:

- Less than about 0.5 to 1 percent gas by volume at the impeller may not have a significant effect on pump head.
- Pump head may be degraded with 1 to 2 percent gas by volume.
- Some pumps may fail to provide significant head at 5 percent gas by volume.
- Most pumps may fail to provide significant head at 10 percent gas by volume.

However, these percentages are a function of flow rate. With respect to developed head, NUREG/CR-2792[11] states that expert opinions on the level of gas ingestion giving negligible degradation ranged from 1 to 3 percent. These experts generally agreed that for flow rates less than 50 percent at best efficiency, the presence of gas might cause gas binding that would not occur at full flow in some pump designs. The experts apparently agreed that gas in the suction lines increased NPSH requirements, but no quantitative data were found. NUREG/CR-2792 also identified a problem that does not appear to be widely recognized. At reduced flow rates with gas ingestion rates that are not normally a problem, gas can accumulate with time and the pump can eventually become gas bound. According to NUREG/CR-2792, this is possible with less than 2 percent gas by volume at low flow rates. Gas binding because of this effect is a potential concern since ECCS pumps are often initially operated at low flow rates when the gas volume passing through the pump may be at a maximum.

---

[11]Kamath, P. S., et al., “An Assessment of Residual Heat Removal and Containment Spray Pump Performance Under Air and Debris Ingesting Conditions,” Creare, Inc., NUREG/CR-2792.

There is some evidence that a multistage pump can tolerate a higher fraction of incoming gas than a single-stage pump without completely losing developed head. This characteristic is attributed to compression of the gas in the early stages so that later stages are exposed to a lower void fraction and consequently continue to develop head. However, this is only true if the flow rate remains a substantial fraction of the best efficiency flow rate. A reduced flow rate may result in pump damage that makes the pump non-functional. For example, in large break loss-of-coolant accidents (LOCAs) where there is little backpressure, the high-pressure ECCS pumps may continue to function with a substantial void fraction at the first stage impeller, but the high backpressure associated with small LOCAs could cause pump damage at the same void fraction.

There is concern that more than 5 percent gas passing through a multistage pump may result in impeller load imbalance that could bend the shaft or initiate shaft cracks, although this did not occur in tests conducted by Palo Verde Nuclear Generating Station in 2004, where flow rates remained high. If such damage occurred, it is not clear how long the pump would continue to operate. Moreover, such damage may not be evident from developed head tests or pump vibration observation. On the other hand, a few cubic feet of finely dispersed 2 percent gas by volume, although undesirable in a multistage pump, may not cause pump damage that is immediately evident if the exposure time was short, pump flow rate remained high, and the exposure did not occur repeatedly.

These considerations lead to the conclusion that the commonly used limit of 5 percent gas into pumps may be reasonable only if a substantial flow rate can be ensured. For low flow rates, it may be a nonconservative limit. Furthermore, such gas percentages are undesirable because of the potential to cause damage to the pump.

(6) Control of Gas

Venting for a fixed time at what are perceived as local high points is often performed to satisfy TS SRs to ensure that gas accumulation in the ECCS and DHR system will not jeopardize operation. However, the SR should reasonably ensure that gas has not affected operability and will not likely accumulate in sufficient quantity to jeopardize operability before the next surveillance. Venting is sometimes performed where the effluent cannot be directly observed. The venting times are sometimes specified, but they may be too short for an unexpectedly large gas accumulation. In such cases, effective corrective actions may include modifying vents to accommodate direct observation and providing actions keyed to the observed venting results.

Although the subject systems are often susceptible to gas accumulation, all plants may not have vent valves at one or more system high points. Furthermore, vents in long, nominally horizontal pipes might not be completely effective in eliminating gas. Licensees have also found vents that were supposed to be installed at a high point but were actually installed at a different location. Where high points are not vented, the important questions are whether the licensee is aware of the potential problems, whether the licensee's controls and practices sufficiently reflect this awareness, and whether modifications should be accomplished. For example, where vents are not installed at high points, UT measurements can provide a check for gas, and a high flow rate may be useful to ensure that gas has been swept from high points. In other cases, design modifications, such as adding vent valves, may be a reasonable approach to problem resolution. For example, one licensee found it needed to install an additional 21 high-point vent valves. Another licensee, who installed an additional 17 vent valves, determined that the primary cause of the gas voiding problem was that the original design specification did not call for a sufficient number of vent valves. No specific NRC requirement mandates the installation of vent valves on the subject systems. However, failure to translate the design basis of assuring the system is maintained sufficiently full of water to maintain operability into drawings, specifications, procedures, and instructions is a violation of Criterion III in Appendix B to 10 CFR Part 50.

In some cases, it may not be necessary to conduct a surveillance to ensure operability. An assessment for such plants that (1) acceptably eliminates other means of introducing gas, (2) establishes acceptable verification that the lines are essentially full following a condition that reduces the discharge line pressure, and (3) establishes an operating history confirming that gas has not accumulated may be adequate justification for not conducting surveillances inside containment or at locations that constitute a hazard to personnel performing the assessment. For example, some three loop plants designed by Westinghouse maintain high pressure safety injection discharge lines at a pressure greater than the RCS operating pressure. This eliminates the potential for leakage from the accumulators or the RCS as a possible means to introduce gas into the discharge lines.

If venting from hazardous locations is necessary to maintain operability, measures such as relocating vent valves could be taken in order to address principles of keeping exposures as low as is reasonably achievable and personnel safety considerations.

With similar justifications and additional considerations, extending the time between surveillances of certain sections of piping may be reasonable. For example, consideration should be given to such conditions as changes in accumulator level and pressure or other indicators of potential gas problems. In regard to significant extension of surveillance times, consideration should be given to the possibility of a previous surveillance, such as a pump test, causing a change in gas behavior, such as a check valve failing to close as tightly as it did before the surveillance, a change that appears to have contributed to the Indian Point Unit 2 event described in the GL. Finally, although not covered by existing TSs, some addressees have increased selected surveillance rates when problems were observed until the root cause of the gas accumulation could be corrected.

Hydrogen is sometimes vented and ignition may be a concern if the area to which the hydrogen is vented is small and not well ventilated. The source of the gas to be vented should be determined and, if the gas is hydrogen, steps to monitor and control the effluent should be considered.