UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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ARLINGTON, TEXAS 76011-4005

February 4, 2008

William R. Brian, Vice President
of Operations
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Entergy Operations, Inc.
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Port Gibson, MS 39150

SUBJECT: GRAND GULF NUCLEAR STATION – NRC IDENTIFICATION AND RESOLUTION OF PROBLEMS INSPECTION REPORT 05000416/2007008

Dear Mr. Brian:

On November 2, 2007, the U.S. Nuclear Regulatory Commission (NRC) completed the onsite portion of a team inspection at your Grand Gulf Nuclear Station. The enclosed inspection report documents the inspection findings which were discussed on December 13, 2007, with you and members of your staff. A supplemental exit meeting was also conducted with Mr. D. Bottemiller on January 24, 2008.

This inspection reviewed activities conducted under your license as they relate to the identification and resolution of problems, compliance with the Commission's rules and regulations and the conditions of your operating license. Within these areas, the inspection involved examination of selected procedures and representative records, observations of activities, and interviews with personnel. The team reviewed cross-cutting aspects of NRC findings and interviewed personnel regarding the condition of your safety conscious work environment at Grand Gulf Nuclear Station. Because this inspection resulted in an extensive review of safety-related heat exchangers which satisfied the requirements of Inspection Procedure 71111.07, this report documents those results as well. As a result, you will receive credit for this biennial heat sink inspection.

The inspectors reviewed 200 condition reports, work orders, associated root and apparent cause evaluations, and other supporting documentation to assess problem identification and resolution activities. Overall, the team concluded that your program was generally effective in identifying, evaluating, and correcting problems. Corrective actions, when specified, were generally implemented in a timely manner, although the team identified a significant number of longstanding equipment problems that were not being resolved in a timely manner. The team concluded that you continue to have problems with the quality of operability assessments, and this is not being effectively addressed.

You performed quality higher-tier self-assessments, but the overall effectiveness was reduced by being slow to implement recommended improvements. We concluded that you are making progress in your efforts to address a trend in human performance, but this has not yet been completely effective. On the basis of interviews conducted during this inspection, we concluded that a positive safety-conscious work environment exists at Grand Gulf Nuclear Station.

Two findings were evaluated under the risk significance determination process as having very low safety significance (Green). These findings were determined to be violations of NRC requirements. However, because these violations were of very low safety significance and the issues were entered into your corrective action program, the NRC is treating these findings as noncited violations, consistent with Section VI.A.1 of the NRC's Enforcement Policy. The noncited violations are described in the subject inspection report. If you contest the violations or the significance of the violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U. S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001, with copies to the Regional Administrator, U. S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas, 76011; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC resident inspector at the Grand Gulf Nuclear Station facility.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Linda J. Smith, Chief
Engineering Branch 2
Division of Reactor Safety

Docket: 50-416
License: NPF-29

Enclosure:
NRC Inspection Report 05000416/2007008
w/attachments: 1. Supplemental Information
2. Information Request

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U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket:	50-416
License:	NPF-29
Report:	05000416/2007008
Licensee:	Entergy Operations, Inc .
Facility:	Grand Gulf Nuclear Station
Location:	P.O. Box 756 Port Gibson, MS 39150
Dates:	October 1, 2007 through January 24, 2008
Inspectors:	N. O'Keefe, Senior reactor Inspector (Team Leader) H. Abuseini, Reactor Inspector J. Adams, Reactor Inspector A. Barrett, Resident Inspector
Accompanying Personnel:	C. Brooks, INPO
Approved By:	Linda Joy Smith, Chief Engineering Branch 2 Division of Reactor Safety

SUMMARY OF FINDINGS

IR 05000416/2007008; 10/1/07 - 01/24/08; Grand Gulf Nuclear Station: Identification and Resolution of Problems, Biennial Heat Sink Performance.

The report covered a 2-week period of inspection by a resident inspector and three region-based inspectors. Two Green noncited violations were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

Identification and Resolution of Problems

The inspectors reviewed approximately 200 condition reports, work orders, associated root and apparent cause evaluations, and other supporting documentation to assess problem identification and resolution activities. The team concluded that the licensee was generally effective in identifying, evaluating, and correcting problems. Corrective actions, when specified, were generally implemented in a timely manner, although the team identified a significant number of longstanding equipment problems that were not being resolved in a timely manner. The team concluded that the licensee continued to have problems with the quality of operability assessments, and this was not being effectively addressed. The licensee performed quality higher-tier self-assessments, but the overall effectiveness was reduced by being slow to implement recommended improvements. The team concluded that the licensee was making progress in their efforts to address a trend in human performance, but this has not yet been completely effective. On the basis of 32 interviews conducted during this inspection, workers at the site felt free to report problems to their management, and were willing to use the corrective action program. An increased awareness and confidence in the Employee Concerns Program was also apparent. The team concluded that a positive safety-conscious work environment exists at Grand Gulf Nuclear Station.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. A noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, was identified for failure to perform an adequate cause analysis for fouling of the Residual Heat Removal Heat Exchanger B on the standby service water side, and implement corrective action to prevent recurrence. This fouling reduced the thermal performance margin to 0.6 percent, but was not treated as a significant condition adverse to quality within the corrective action program. The licensee chose to temporarily restore margin by increasing the flow rate, but this did not remove or stop the fouling from continuing to occur. This finding has cross-cutting aspects in the decision-making area of Human Performance (H.1.b) because the licensee's decision-making in response to this degraded condition did not use conservative criteria in deciding when to clean this heat exchanger, and did not verify that the underlying assumptions remained valid.

Failure to treat Residual Heat Removal Heat Exchanger B degradation as a significant condition adverse to quality, and perform an adequate cause analysis, and implement corrective action to prevent recurrence was a performance deficiency. This was more than minor because, if left uncorrected, it could lead to a more significant safety concern in that the system could become fouled enough to prevent removing the required heat load without the licensee recognizing this condition. This finding affected the Mitigating Systems and Barrier Integrity Cornerstones, since this component was required for both decay heat removal and containment heat removal functions. In accordance with the Phase 1 Significance Determination Process instructions, the significance was assessed using the Mitigating Systems Cornerstone, since this represented the dominant risk. This finding was determined to have very low safety significance (Green) during a Phase 1 Significance Determination Process, since it was confirmed to not involve loss of the design heat removal capability. This issue was entered into the licensee's corrective action program under Condition Report 2007-5766. (Section 4OA2.e.1(b)(1))

- Green. A noncited violation of 10 CFR 50, Appendix B, Criterion XI, "Test Control," was identified because the licensee's thermal performance test procedures for the residual heat removal heat exchangers were inadequate to ensure the quality of the test results. Specifically, the test procedure failed to specify adequate prerequisites for minimum heat load and use of high-accuracy instrumentation. This resulted in test results used to meet commitments for the Generic Letter 89-13 test program which provided little useful information due to high inaccuracy.

Failure to adequately test and trend the thermal performance of the residual heat removal heat exchangers was a performance deficiency because it masked the actual thermal performance to the point where the licensee did not recognize the onset of fouling. The team determined that these heat exchangers began to experience fouling between 1997 and 1998, but this was not recognized. In the case of Residual Heat Removal Heat Exchanger B, the degraded performance was determined to be sufficient to make the fouling factor exceed the design value, necessitating compensatory action to be able to show continued operability. This was more than minor because, if left uncorrected, it could lead to a more significant safety concern in that the system could become fouled enough to prevent removing the required heat load without the licensee recognizing this condition. This finding affected the Mitigating Systems and Barrier Integrity Cornerstones, since this component was required for both decay heat removal and containment heat removal functions. In accordance with the Phase 1 SDP instructions, the significance was assessed using the Mitigating Systems Cornerstone, since this represented the dominant risk. This finding was determined to have very low safety significance (Green) during a Phase 1 Significance Determination Process, since it was confirmed to not involve loss of the design heat removal capability. This issue was entered into the licensee's corrective action program under Condition Report 2008-0412. (Section 1R07)

B. <u>Licensee-Identified Violations</u>

None

REPORT DETAILS

4 OTHER ACTIVITIES (OA)

4OA2 Problem Identification and Resolution (71152B)

The inspectors based the following conclusions, in part, on a review of issues that were identified in the assessment period, which ranged from March 15, 2005, (the last biennial problem identification and resolution inspection) to the end of the on-site portion of the inspection on November 2, 2007. The issues discussed in this report are divided into two groups. The first group (current issues) included problems identified during the assessment period where at least one performance deficiency occurred during the assessment period. The second group (historical issues) included issues that were identified during the assessment period where all the performance deficiencies occurred prior to the assessment period.

a. Assessment of Corrective Action Program Effectiveness

1. Inspection Scope

The team reviewed items selected across the seven cornerstones of safety to determine if problems were being properly identified, characterized, and entered into the corrective action program for evaluation and resolution. Specifically, the team selected and reviewed approximately 200 condition reports (CRs) from approximately 12,000 that had been issued between March 2005 and November 2007. The team also performed field walkdowns of selected systems and equipment. Additionally, the team reviewed a sample of self-assessments, trending reports and metrics, system health reports, and various other documents related to the corrective action program.

The team evaluated condition reports, work orders, and operability evaluations to assess the licensee's threshold for identifying problems, entering them into the corrective action program, and the ability to evaluate the importance of adverse conditions. Also, the licensee's efforts in establishing the scope of problems were evaluated by reviewing selected logs, work requests, self-assessments results, audits, system health reports, action plans, and results from surveillance tests and preventive maintenance tasks. The team reviewed work requests and attended the licensee's daily Condition Review Group (CRG) meetings to assess the reporting threshold, prioritization efforts, and significance determination process, as well as observing the interfaces with the operability assessment and work control processes.

The team reviewed a sample of condition reports, apparent cause evaluations (ACEs), and root cause evaluations (RCEs) performed during this period to ascertain whether the licensee properly considered the full extent of cause and extent of condition for problems, as well as assessing generic implications and previous occurrences. The team assessed the timeliness and effectiveness of corrective actions, completed or planned, and looked for additional examples of similar problems.

The team also conducted interviews with plant personnel to identify other processes that may exist where problems may be identified and addressed outside the corrective action program.

A review of the standby service water (SSW) system was performed for a 5-year period to determine whether problems were being effectively addressed. The team conducted a walkdown of this system to assess whether problems were identified and entered into the work order process.

2. Assessments

(a) Assessment - Effectiveness of Problem Identification

The team concluded that problems were generally identified and documented in accordance with the licensee's corrective action program guidance and NRC requirements. The licensee was identifying problems at an appropriately low threshold. The licensee had written approximately 12,000 condition reports during the 2.5 year period of review. This demonstrated that the licensee was effectively identifying problems and entering them into the corrective action program.

The team identified a number of examples where the licensee did not always completely identify problems and document them in CR's. Examples included:

- Failure to identify and correct the cause for elevated temperatures in the Division I emergency diesel generator that resulted in the system being inoperable. (CR 2007-0378) [Current Issue]

- Failure to identify that corrective actions for the January 30, 2007 failure of the Division I emergency diesel generator did not address the cause, when the temperature control valve thermal elements that were removed were found to be functioning properly. (CR 2007-2255) [Current Issue]

- Fire brigade drill critique failed to identify a number of performance deficiencies (CR 2005-1872) [Current Issue]

- Failure of a temperature probe on Reactor Recirculation Pump A, which was required to function in order to shift pump speeds, was not documented in a condition report. This contributed to a reactor loop flow mismatch when operators unsuccessfully attempted to shift speed anyway. (CR 2006-2329) [Current Issue]

- Failure to identify loose and missing fasteners in a safety-related breaker associated with the SSW system. (CR 2007-3081) [Current Issue]

- Foreign material was found inside a containment purge compressor oil cooler during maintenance, but this was not documented in a CR. (CR's 2007-3879 and 2007-3911) [Current Issue]

(b) Assessment - Effectiveness of Prioritization and Evaluation of Issues

The team reviewed CRs that involved operability issues to assess the quality and timeliness of operability assessments. The operability assessment program was very good, and effectively incorporated NRC guidance. However, the team concluded that the station personnel were frequently not assessing operability and documenting the process sufficiently to meet the standards of the program. In general, operability assessment documentation was limited, making it difficult to reproduce what was considered during the assessment. Routine operability assessments, typically performed without significant engineering input, generally involved little discussion about what function(s) were impacted and why the performance was sufficient to fulfill these functions. The team concluded that many operability assessments that were based on engineering judgment were not labeled as such, and the procedural requirements for this type of result were not followed to confirm that the assumptions were correct. Also, some issues involved establishing compensatory measures, but these were not always identified as compensatory measures, nor was it apparent that procedural requirements for issues involving compensatory measures were being followed. Many issues involving degraded conditions that were judged to be operable were not labeled or tracked as degraded, nor were they monitored to ensure that the level of degradation did not increase. Assumptions used in assessing operability were frequently not clearly stated. Also, the consideration of whether the function being evaluated would remain operable throughout the mission time was not always apparent. Problems with the quality of operability assessments has been raised during NRC inspections during the review period. The team reviewed the licensee's actions to improve in this area, and concluded that these actions have not been effective. While training was conducted using case studies, the team noted that the licensee had failed to recognize that they were not following the operability assessment procedures, as described above.

Some examples of evaluation problems included:

- Operators failed to notify reactor engineering to perform an evaluation when a degraded reactor jet pump failed to meet the acceptance criteria for a surveillance functional test (CR's 2007-1061 and 2007-1071) [Current Issue]

- Two examples were identified where the risk due to maintenance was not evaluated. (CR's 2006-1041 and 2006-1277) [Current Issue]

- The licensee failed to assess the impact to operability when it was identified that oil in safety related motors had the wrong viscosity (CR's 2006-3201 and 2006 3183) [Current Issue]

- Inadequate operability evaluation for emergency diesel generator temperature control valve failure because it relied on unsupported engineering judgment and did not assess the possible causes. (CR 2007-2256) [Current Issue]

- Inadequate operability evaluation for a degraded switchgear ventilation system because the licensee used several nonconservative assumptions and failed to evaluate the potential for changing weather conditions. (CR 2007-0554) [Current Issue]

- The potential for scaling or heat exchangers cooled by the ultimate heat sink was raised by the team. The licensee's initial operability assessment evaluated the issue using the water quality at the time, rather than the hardest water allowed by the chemistry specifications. (CR 2007-4860) [Current Issue]

- A question was raised about the reactor core isolation cooling turbine governor response while the system was out of service. The condition was assessed, but not documented as an operability assessment since the system was already declared inoperable for maintenance. Without an operability assessment and tracking, the system could have been returned to service without first completing the operability assessment. (CR 2007-4767) [Current Issue]

- The operability assessment for a steam leak on a reactor water cleanup heat exchanger did not document what functions that were evaluated. It incorrectly stated that no Technical Specification limits existed for reactor coolant system leakage inside containment, when GGNS Technical Specifications have limits for identified, unidentified, and pressure boundary leakage. The assessment did not document consideration of the impact to room temperature and the leakage isolation system, or the ability to maintain water chemistry. Additionally, this was a degraded condition which should have included measures to monitor the condition to ensure that it did not get worse. (CR 2007-3468) [Current Issue]

- Pipe wall thinning was assessed when the minimum wall thickness criterion was not met. Operability was justified by use of an ASME Code Case, without assessing potential impact to functions beyond leak tightness. Since this was a degraded condition subject to additional degradation, the licensee's assessment should have included compensatory measures to monitor the degradation. (CR 2007-4227) [Current Issue]

The team reviewed the root cause evaluation and apparent cause evaluation procedures, as well as samples of both types of evaluations. The qualifications records for the root cause evaluators were also reviewed. The team concluded that Grand Gulf Nuclear Station had a good root cause determination process and effectively implemented these processes. A variety of root cause analysis methodologies were utilized in a team setting, and in general were able to determine the cause for the specific problem. Appropriate corrective actions were identified to address each cause. External operating experience and off-site expertise were appropriately utilized in their evaluations.

By comparison, the quality of ACEs was inconsistent. Some were very good, including a few that approached the rigor of a root cause evaluation. However, many samples did not appear to use a disciplined methodology, and the question being answered did not always adequately cover the scope of the apparent problem. Also, the level of documentation was sometimes insufficient to determine the adequacy of the review. Some examples were noted where the problem recurred because the apparent cause evaluation was not sufficiently rigorous to have identified the right cause and corrective actions. Two examples are discussed in Section 4OA2.e.1(b)(1).

(c) Assessment - Effectiveness of Corrective Actions

The inspectors reviewed plant records, primarily CRs and work orders, to verify that corrective actions were developed and implemented, including corrective actions to address common cause or generic concerns. Additionally, the inspectors reviewed a sample of CRs that addressed past NRC identified violations for each cornerstone to ensure that the corrective actions adequately addressed the issues as described in the inspection reports. The inspectors also reviewed a sample of corrective actions closed to other CRs, work orders, or tracking programs to ensure that corrective actions were still appropriate and timely.

Overall, the team concluded that the licensee developed appropriate corrective action to address problems. The team assessed the station’s practice of closing condition reports to work orders, and noted that the process made it possible to close a CR to a Priority 5 work order; however, under the work control process, Priority 5 work orders had no timeliness goals associated with them. This created the possibility that corrective actions closed to Priority 5 work orders may not get corrective action in a timely manner. The corrective action program contains a requirement to periodically brief the condition review group on the status of CR’s in this category, but a station self-assessment noted that this was not being done until recently.

The team identified an example of narrow corrective actions for poor initial licensed operator exam quality in 2005, which contributed to a high exam failure rate on the 2007 exam. Corrective actions did not address the quality of weekly exam content during the training process to ensure the students would have adequate exposure to the higher cognitive type of exam questions, or to review their exam bank to ensure the existing questions were up to the newer standards. As a result, a high failure rate was experienced during the 2007 initial operator license exam. When this was recognized, the licensee performed a high-quality cause analysis and identified corrective actions that appeared appropriate to address the causes.

The team identified numerous examples of longstanding problems that have not been effectively resolved. The nature and extent of these examples demonstrated that the corrective actions were either not sufficiently broad or were not timely for some of the more difficult equipment problems facing the station. Despite the longstanding nature of the problems, a number of the examples were not addressed during the last refueling outage. Examples include:

- Standby service water heat exchangers are experiencing fouling, affecting multiple systems and divisions. Despite years of known fouling, the cause has not been properly identified, and effective corrective actions have not been taken. [Current Issue]

- Resin was inadvertently spread through the radwaste system and migrated to the condensate, feedwater and reactor coolant systems, affecting chemistry and possibly core reactivity over the last 2 years. Cleanup efforts have been slow. [Current Issue]

- The hydrogen water chemistry system had a number of problems affecting system reliability, which have impacted water chemistry and source term, as well as having contributed to plant transients. [Current Issue]

- The site radio system and plant announcing system, used for communications during normal and emergency operations, are ineffective in certain areas of the plant. Upgrading the radio system resulted in shadow zones where radios do not work properly. The announcing system is not sufficiently audible in some areas, and has been that way for an extended period of time. [Current Issue]

- There have been a series of thermal relief valves associated with the SSW system with unacceptable setpoint drift. Problems continue to occur, with two reported during this inspection, but the licensee has not identified a clear cause. [Current Issue]

- The controls for radial wells in the control room have not worked for years. This was the only item on the operator workaround list during this inspection, yet the team noted that there was no condition report or work order open to address the issue. Local operation is challenged during seasonal high river levels, because operators need a boat to get to the local pump controls. The team concluded that this issue was not receiving the level of attention appropriate for an operator workaround. [Current Issue]

- The main turbine seal steam regulating valves have not worked correctly for 2 years. This was not addressed during the last outage. Troubleshooting was conducted with the plant on line on September, 18, 2007, which resulted in lowering main condenser vacuum which necessitated an unplanned power reduction. The team concluded that this issue involved an operator workaround, since manual action is needed to be able to maintain the main condenser as a heat sink during a plant trip or significant transient, but this was not identified on the operator workaround list. (CR 2007-4626) [Current Issue]

- The local power range monitor detectors in position 50-43 have been inoperable for the more than three operating cycles. Replacement efforts have been ineffective during previous outages, although no repair was attempted during the last outage. While considerable redundancy remains available, this important system has been allowed to remain degraded for years, and corrective actions have not been timely or effective. (CR 2001-0798) [Current Issue]

- There are erosion issues with both control rod drive flow control valves, which have had a number of ineffective attempts to repair or replace over several outages. [Current Issue]

- The containment pool liner has had detectable leakage for years, but no action has been taken to identify and correct the source. Inspectors identified that trending of the leakage had been halted, and operators recorded “sat” on daily leakage logs, regardless of the amount of observed leakage. (CR’s 2006-3369 and 2006-3500) [Current Issue]

Additionally, a noncited violation (NCV) was issued in Inspection Report 2007-03 for an example where the leakage detection system had exceeded the Maintenance Rule performance criteria for functional failures, but the licensee failed to recognize this and consider the system for goal setting and corrective actions in accordance with the Maintenance Rule Program. (CR 2007-2955) [Current Issue]

Other examples of ineffective or untimely corrective actions included:

- A 7 foot long, half-inch wide crack in the concrete ceiling of the reactor water cleanup heat exchanger room has existed for years, but was not evaluated or corrected. (CR 2007-1970) [Current Issue]

- Noncited violation for inadequate corrective actions for standby service water leakage from a drywell purge compressor oil cooler drain plug. (CR 2006-4762) [Current Issue]

- Noncited violation for failure to prevent recurrence for a significant condition adverse to quality, due to repetitive failures of emergency diesel generator cylinder heads due to corrosion fatigue. Corrective action was appropriate, but was not implemented in a timely manner. (CR 2006-1955) [Current Issue]

- Untimely corrective actions for a design deficiency with condensate storage tank level instrumentation that was identified in 1999 and corrected in 2005. (CR 2006-1096) [Historical Issue]

Human Performance Improvement

The licensee's CAP trending and the NRC's inspection findings indicate that Grand Gulf Nuclear Station developed a negative trend in human performance errors. The team reviewed the licensee's human performance improvement efforts to address this issue. The apparent cause evaluation performed in response to this trend was well-focused, and recommended corrective actions that appeared appropriate to address the issues. It was apparent from routine meetings and CR's that the licensee was vigorously trying to identify human performance issues; however this has not been completely effective.

The team noted the following examples of human performance issues:

- Failure to follow procedure during radiography operations. (CR 2007-1582) [Current Issue]

- Failure to follow procedure when two outage workers entered a high radiation area in violation of the radiation work permit. (CR 2007-1442) [Current Issue]

- The team noted a trend in mixed lube oil or wrong lube oil in plant components. Fourteen CRs during the review period involved mixed lube oil or lube oil with high water content. The CRs documenting the problems focused on the equipment and the oil, but did not address the human performance aspects. Corrective actions for this trend have not been fully effective, because

CR 2007-5120 for finding the wrong oil in reactor core isolation cooling system turbine was written during this inspection.

- Failure to follow procedure resulted in a significant plant service water leak. (CR 2006-0219) [Current Issue]

- Failure to follow procedure for shifting reactor recirculation pump speed contributed to mismatched loop flows. (CR 2006-2329) [Current Issue]

- Failure to follow procedure during a surveillance test resulted in inadvertent isolation of Division I and III switchgear ventilation. (CR 2006-4394) [Current Issue]

- Unauthorized troubleshooting was performed without a procedure that resulted in a short circuit in a circuit associated with Control Rod Drive Pump A. (CR 2006-4474) [Current Issue]

- Six examples were identified where workers were not securing loose items in the auxiliary building in order to prevent damage to safety related equipment. (CR 2006-3836) [Current Issue]

- Failure to follow procedure resulted in inadvertently tripping a plant service water pump. (CR 2005-2575) [Current Issue]

- Failure to follow procedure resulted in inadvertently disabling alarms for the Division II emergency diesel generator. (CR 2005-2886) [Current Issue]

- Trend identified by the licensee for having a high number of electronic alarming dosimeter (EAD) alarms. Condition Report 2005-4202 determined that radiation protection (RP) personnel were not always selecting appropriate EAD alarm setpoints. A similar trend was reported in CR 2006-2951, but this time the cause reported was that RP personnel did not fully understand the radiological conditions before entering radiological areas. The team noted that both of these issues involved human performance problems, but neither CRs received a human performance evaluation. [Current Issue]

- The team identified a trend in inadequate foreign material exclusion practices. Some examples include:

    - Foreign material was found inside a containment purge compressor oil cooler during maintenance. (CR’s 2007-3879 and 2007-3911) [Current Issue]

    - A bolt was dropped into the reactor vessel during an outage. (CR 2007-1677) [Current Issue]

    - Foreign material exclusion plugs not removed from reactor feedwater pump lube oil system following maintenance. (CR 2007-2158) [Current Issue]

- Foreign materials not removed from containment during closeout inspection. (CR's 2005-3520 and 2006-0236) [Current Issue]

- Resident inspectors noted 25 CR's documenting foreign material control problems. (CR 2005-4306) [Current Issue]

- Numerous chemical control and storage issues occur (29 in 2006, and eight in 2007). The Category B CR 2006-4507 was ineffective, because they continued to be identified during this inspection. [Current Issue]

b. Assessment of the Use of Operating Experience (OE)

1. Inspection Scope

The team examined the licensee's program for reviewing industry operating experience, including reviewing the governing procedure and self-assessments and interviewing the OE program owner. A sample of operating experience notification documents that had been issued during the assessment period were reviewed to assess whether the licensee had appropriately evaluated the notification for relevance to the facility. The team also then examined whether the licensee had entered those items into their corrective action program and assigned actions to address the issues. The team reviewed a sample of root cause evaluations and significant CRs to verify if the licensee had appropriately included industry operating experience.

2. Assessment

Overall, the team determined that the licensee had appropriately evaluated industry operating experience for relevance to the facility, and had entered applicable items in the corrective action program. The team concluded that the licensee was also evaluating industry operating experience when performing root cause and apparent cause evaluations. Both internal and external operating experience was being incorporated into lessons learned for training and pre-job briefs.

The team noted that root and apparent cause evaluations were being required to evaluate whether internal or external operating experience was available associated with the event or failure being examined, and whether the evaluation and actions to address those items had been effective. Additionally, root cause evaluations include an assessment as to whether the issue being evaluated has potential application to other plants. Several recent root cause evaluations were effective in identifying relevant operating experience which had been ineffectively addressed. The team did not identify any additional examples.

c. Assessment of Self-Assessments and Audits

1. Inspection Scope

The inspectors reviewed a sample of licensee self assessments and audits to assess whether the licensee was regularly identifying performance trends and effectively addressing them. The team also reviewed audit reports to assess the effectiveness of assessments in specific areas. The specific self-assessment documents reviewed are listed in the Attachment.

2. Assessment

The team concluded that the licensee had a good self-assessment process, but was still making progress towards implementing the process as it was intended. Grand Gulf Nuclear Station senior management was very involved in developing the topics and objectives of self-assessments. Particular attention was given to assigning team members with the proper skills and experience to do an effective self-assessment and to include people from outside organizations.

A multi-tiered approach was used which applied a graded level of effort based on the subject. The licensee was effective in utilizing outside experts, both within Entergy Operations, Inc. and from outside the company, to help assess performance. From the samples reviewed, most Tier 2 and 3 assessments had outside participation. Also, the station performed Tier 2 and Tier 3 assessments by comparing station practices and performance to industry best practices, rather than from a minimum compliance standpoint. The team noted that most of these assessments provided meaningful assessments and worthwhile recommendations for improvement.

However, there is a wide variety in the assessment quality among the Tier 2, 3, and 4. Tier 2 assessments, initiated mostly from the corporate level, were consistently of high quality. These assessments were of good depth and effectively identified problems and trends. The results were generally broad assessments of performance, and included specific examples of problems and recommendations for improvement.

Tier 3 assessments were directed by the site senior management team to address site priorities and issues. These assessments were less consistent in the quality of assessments and recommendations because the documentation was sometimes limited. Some assessment reports did not explain the scope of the review effort, making it difficult to understand the basis for the conclusions. In some cases, the conclusions were narrowly focused on the problems identified, without providing an overall assessment.

Tier 4 assessments were performed at the direction of individual managers to meet work group needs. These were typically performed by one individual from the organization being assessed. These were generally limited to compliance reviews, with little assessment or recommendations for improvement. The team concluded that Tier 4 assessments were of limited value.

The team reviewed recommendations made in self-assessments and the actions assigned as a results of those recommendations. Many of the recommendations were handled outside the corrective actions program by assigning them to the Grand Gulf Learning Organization (GLO) process. The team noted that these were often given a low priority and were not implemented in a timely manner, which reduced the effectiveness of the overall self-assessment process. The relative priority and timeliness appeared to be related to differences between the GLO process and the regular corrective action program.

The team reviewed the licensee's self-assessment activities in the areas of safety culture and safety conscious work environment. Details are discussed in Section 4OA2.d.

d. Assessment of Safety Conscious Work Environment

1. Inspection Scope

The team interviewed 32 individuals from different departments representing a cross section of functional organizations, including supervisory and non-supervisory personnel. These interviews assessed whether conditions existed that would challenge an effective safety conscious work environment. The team reviewed the results of the 2006 Nuclear Safety Culture Assessment conducted by Synergy Consulting Services, and the corrective action plan to address the findings. The inspectors reviewed procedures and training materials used to implement the safety conscious work environment and safety culture programs at the site, and discussed them with the site Employee Concerns Program coordinator. The team also discussed the number and general themes for issues received by the Employee Concerns Program, and compared them to the types of allegations the NRC received during the same period.

2. Assessment

The inspectors concluded that a safety conscious work environment exists at the Grand Gulf Nuclear Station. Employees felt free to enter issues into the CAP, as well as raise safety concerns to their supervision, the Employee Concerns Program, and the NRC. Improvement was apparent from these interviews in some areas identified as concerns during the 2005 Nuclear Safety Culture Assessment. Individuals interviewed were all familiar with the CAP, and had used the process to report and correct problems. Additionally, many interviewees believed changes to the CAP were improving the process, and indicated support for the improvements.

During the 2005 biennial PI&R inspection, the team had received a few isolated comments regarding: 1) a reluctance to use the site employee concerns program; 2) production pressure; and 3) the impact of staff reductions on work load and the ability to identify safety issues, although all personnel interviewed believed that potential safety issues were being addressed. The team noted that the Synergy 2006 Nuclear Safety Culture Assessment identified similar comments. The team determined that licensee management was aware of the workers' perceptions and was taking action to address them through the 2006 Nuclear Safety Cultural Assessment Action Plan. During the interviews conducted for this inspection, the team received no negative comments in these areas. In contrast to the previous issues, the comments received during this inspection were predominantly positive that individuals were willing to report problems, enter them into the corrective actions program, and use the Employee Concerns Program if appropriate. Workers also expressed the opinion that management was receptive to problem reporting.

Some of those interviewed expressed a concern with the timeliness of corrective actions for problems with routine significance. For safety significant issues, there was confidence that the issue would be addressed. However, for issues classified as routine priority (Category C and D issues), there was less confidence that those issues would be ultimately resolved because of lack of resources.

e. Specific Issues Identified During This Inspection

1 Failure to Identify Cause and Correct Significant Fouling in RHR Heat Exchanger

(a) Inspection Scope

The team performed a review of 5 years of problem reports for the SSW system. In particular, problems involving fouling of safety-related heat exchangers were reviewed. The chemistry control program and water chemistry trends were assessed to determine whether the licensee was adequately controlling biological fouling and corrosion of system materials. Lab reports for foulant sample analyses were reviewed. The team reviewed the licensee's program and test results for thermal performance testing and trend monitoring. The team also observed the condition of the Division 2 emergency diesel generator (EDG) jacket water heat exchanger when it was opened for cleaning on November 1, 2007, as well as observing the condition of both SSW basins.

Based on initial review, attention was focused on the test, inspection, and operability evaluations for RHR Heat Exchanger B. Thermal performance data for this heat exchanger dating back to 1992 were reviewed.

(b)(1) Findings

Introduction. A Green noncited violation of 10 CFR 50, Appendix B, Criterion XVI, was identified for failure to perform an adequate cause analysis for fouling of the RHR Heat Exchanger B, and failure to implement effective corrective action to prevent recurrence. This fouling constituted a significant condition adverse to quality because it significantly reduced the thermal performance margin of the heat exchanger, but this issue was not treated as one within the corrective action program. This finding has cross-cutting aspects in the decision-making area of Human Performance (H.1.b) because the licensee's decision-making in response to this degraded condition did not use conservative criteria in deciding when to clean this heat exchanger, and did not verify that the underlying assumptions remained valid during the extended period between the operability assessment and the planned cleaning.

Description. The standby service water system provides cooling to safety related heat loads by supplying water to various safety related heat exchangers. Each train has a large basin to hold the 7 million gallon supply reservoir. These basins are automatically maintained full with makeup water which is drawn from wells below the Mississippi River shore.

Grand Gulf historically experienced fouling of heat exchangers in the SSW system for years. The licensee attempted to manage the amount of fouling by cleaning individual heat exchangers, without fully determining the cause of the fouling or characteristics of the material which was coating heat exchanger tubes and forming sludge at the bottom of the basins. However, the PI&R team concluded that, in the case of RHR Heat Exchanger B, thermal performance was not being managed effectively. Other heat exchangers cooled by the SSW system also experienced degraded performance. However, these are more accessible for cleaning than the RHR heat exchangers, and the licensee was more effective in cleaning them.

In 2002, thermal performance testing on RHR Heat Exchanger B identified that thermal margin was reduced to 102.4 percent of design. An apparent cause evaluation incorrectly concluded that there was no actual degraded thermal performance, and that testing problems were affecting the accuracy and the ability to trend the data. At the next outage (2004), RHR Heat Exchanger A was tested to have similar performance (102.0 percent margin) using a somewhat improved method. The team concluded that this essentially validated the results of the previous test on the RHR Heat Exchanger B.

In 2005, RHR Heat Exchanger B was chemically cleaned and opened for the first time since construction in order to perform eddy current testing. A black film covered the tube surfaces, and made it difficult to push eddy current probes through the tubes (some probes were broken because of this). The licensee installed a number of tube plugs due to pitting, but no cause determination was performed to assess the cause of the pitting. The licensee did not initiate mechanical cleaning during this outage, even though the tubes were coated with foulant and the heat exchanger was already in a condition to clean. Sludge samples from the tubes were sent to an offsite lab, but the results were not used to identify the specific cause of the fouling. The apparent cause was vaguely attributed to poor water quality, without explaining how this resulted in fouling.

Shortly after this outage, in November 2005, RHR Heat Exchanger B was tested using a high-accuracy special test method developed by a consultant. The result was 100.6 percent margin. The licensee decided to increase the thermal margin by raising the flow rates to both RHR heat exchangers (by reducing flow to other heat loads supplied by SSW). The team noted that the licensee inappropriately removed the RHR heat exchangers from tracking as “operable but degraded,” based on having improved the margin by about 1.8 percent. An operability evaluation was performed to justify being able to remove the design basis heat loads, although this relied upon somewhat less conservative conditions than the design basis assumed. Each RHR heat exchanger was then scheduled for cleaning during the next outage when they were normally scheduled to be tested. Thus, RHR Heat Exchanger A was cleaned in March 2007, and RHR Heat Exchanger B was scheduled for cleaning in fall 2008.

On November 1, 2007, the Division 2 emergency diesel generator jacket water heat exchanger was opened for scheduled cleaning. The tubes were inspected by the team and found to have a considerable amount of black foulant, even though it had been mechanically cleaned 18 months earlier. A sample was sent to two offsite labs, and the results were interpreted by a cooling water chemistry consultant. The results indicated that the black material was composed of both corrosion products (copper, iron, and zinc) and biological microfouling. The sulfate-reducing bacteria present cause pitting due to micro-biologically induced corrosion (MIC), and the slime-forming bacteria present act to protect the sulfate-reducing bacteria from the effects of biocide.

The team concluded that the licensee did not treat the significant loss of heat transfer margin as a significant condition adverse to quality, perform an adequate cause analysis, or take effective corrective action for the degraded RHR heat exchangers' condition. In particular, action was take to increase margin just enough to go the 3 years to the next normal opportunity to clean, rather than cleaning RHR Heat Exchanger B in a prompt manner.

The team concluded that it was inappropriate to remove the RHR heat exchangers from the operable but degraded category. These components remained degraded because the heat transfer capability was still significantly reduced. The licensee's action did not correct the fouling that had already occurred, nor did it prevent further degradation due to continued fouling. Increasing the SSW flow increased the thermal performance margin by 1.8 percent. This action met the EN-OP-104, "Operability Determinations," Revision 2, definition of a compensatory measure in that is was an interim step to enhance the capability until final corrective action could be completed. Guidance contained in Regulatory Issue Summary 2005 20 and EN-OP-104 specify that conditions that require interim compensatory measures to demonstrate operability should be resolved more promptly, because such reliance suggests a greater degree of degradation. The licensee considered the flow rate increase to be a permanent change, although the team concluded that the intent of this action was to compensate for a loss of thermal performance margin due to fouling, regardless of whether it was temporary or permanent. In accordance with EN-OP-104, the licensee should have continued to track this issue as "OPERABLE - COMP MEASURES" in order to periodically verify that the train remained operable. The team noted that removing these heat exchangers from the category of "operable but degraded," the licensee failed to track them such that they would be cleaned at the next outage or evaluated for continued operability. As a direct result, RHR Heat Exchanger B was not scheduled for corrective action for 3 years after the low margin test results were obtained without any performance test to assess continued operability. The licensee also did not implement the concept that operability assessment is supposed to be a continuous process in this instance.

The team concluded that the chemistry control program for SSW was ineffective in several ways:

- The chemistry control program allowed enough corrosion such that corrosion products built up on heat exchanger tubes and impacted the thermal performance of the heat exchangers. This corrosion was at least partially apparent in the results of corrosion coupon monitoring, since the team noted that the mild steel samples were exhibiting 1.3 - 1.7 mils per year loss due to corrosion, although the licensee did not change the treatment to stop this corrosion. The licensee failed to recognize that the corrosion, while not significantly challenging the structural integrity of the system, was allowing degraded heat transfer in the heat exchangers.

- The licensee had discontinued the practice of draining and cleaning the SSW basins every 3 years in 1999. After that time each SSW basin was vacuumed to remove sludge once, in 2003. A consultant report indicated that the basin sludge contained calcium phosphate, which was the product of hard water and anti-scaling chemicals. This indicated that, at times, impurities were allowed to build up excessively. When the licensee stopped periodic draining and refilling, impurities built up through evaporation, chemical addition, and addition of makeup water with impurities. This was not corrected until late 2006, when both basins received extensive feed and bleed operations until impurities were significantly lowered. However, the sludge that had formed was not removed, so the problem was only partially addressed.

- The licensee performed infrequent biocide treatments in the bulk water in the basins. Hypochlorite was added only twice per year. The licensee intended to use the water treatment program to primarily addressed SSW piping rather than the bulk water in the basins. Chemicals were added during periodic pump runs just prior to securing the SSW pump, with the intent of placing the system in a condition similar to lay-up. In this manner, a small amount of non-oxidizing biocide was added to the pipes. The combined result of the program was to permit an environment conducive to bacteria growth in the basins due to ineffective in biocide treatment, since bacteria from the basins would be introduced into the system each time a pump was run.

- Makeup water was not effectively treated to kill bacteria while adding water to SSW basins. The biocide treatment was performed briefly twice per day in the makeup system, which was designed for killing bacteria in the open-loop non-safety service water system, not the closed-loop SSW system.

- Corrosion was observed in piping in the SSW basins. This was corrected with coating repairs and introduction of a partial cathodic protection system, without considering changes to the water treatment program. This was a missed opportunity to recognize that the basin water was not being adequately treated.

The chemical sampling and corrosion monitoring programs were not sufficiently sensitive to detect corrosion and bacteria, or to trigger changes in the water treatment program. Despite years of fouling, the SSW chemical treatment strategy did not change since it was instituted in the early 1990s.

Analysis: Failure to recognize that RHR Heat Exchanger B degradation was a significant condition adverse to quality and perform an adequate cause analysis and implement corrective action to prevent recurrence was a performance deficiency. Licensee records indicated that fouling had degraded all heat exchangers cooled by SSW for years, affecting both trains of RHR, EDG, emergency core cooling system pump bearing coolers, pump and switchgear room coolers, safety chillers, etc. In the case of RHR Heat Exchanger B, the degraded performance was determined to be so significant that the fouling factor exceeded the design value, and continued operability to the next test could only be justified by increasing the flow rate. This was more than minor because, if left uncorrected, it could lead to a more significant safety concern in that the system could become fouled enough to prevent removing the required heat load without the licensee recognizing this condition. This finding affected the Mitigating Systems and Barrier Integrity Cornerstones, since this component was required for both decay heat removal and containment heat removal functions. In accordance with the Phase 1 SDP instructions, the significance was assessed using the Mitigating Systems Cornerstone, since this represented the dominant risk. This finding was determined to have very low safety significance (Green) during a Phase 1 SDP, since it was confirmed to not involve loss of the design heat removal capability.

This finding has cross-cutting aspects in the decision-making area of Human Performance (H.1.b) because the licensee's decision-making in response to this degraded condition did not use conservative criteria in deciding when to clean this heat exchanger, and did not verify that the underlying assumptions remained valid.

Enforcement: RIS 2005-20, "Revision to Guidance Formerly Contained in NRC Generic Letter 91-18, "Information to Licensees Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and on Operability," specifies that degraded or nonconforming structures, systems, and components shall be corrected in a timely manner commensurate with the safety significance. It further states that when a licensee fails to correct the condition at the first available opportunity or appropriately justifies a longer completion schedule, then the NRC would consider taking enforcement action. Because the licensee failed to correct ongoing fouling of RHR Heat Exchanger B that caused significant loss of heat transfer capability, and failed to justify a longer completion time when they did not correct the fouling at the first outage between November 2005, and December 2007, the NRC has concluded that the licensee has not been timely in correcting this degraded condition.

Part 50 of Title 10 of the Code of Federal Regulations, Appendix B, Criterion XVI requires, in part, that for significant conditions adverse to quality, the licensee shall determine the cause of the condition and take corrective action to preclude repetition. Contrary to this, the licensee failed to perform an adequate cause evaluation and did not take corrective action to remove the material fouling the RHR Heat Exchanger B. Specifically, on September 22, 2005, the licensee identified that RHR Heat Exchanger B had experienced a significant loss of thermal performance due to ongoing fouling, and had only 0.6 percent margin to its design basis required capability. This was a significant condition adverse to quality, but was not treated as one within the corrective action program. Because this violation was of very low safety significance and was entered into the licensee's corrective action program under CR 2007-5766, this will be treated as a noncited violation in accordance with the NRC Enforcement policy: NCV 05000416/2007008-01, Failure to implement effective corrective action in response to significant heat exchanger fouling.

(b)(2) Assessment of the Continued Operability of RHR Heat Exchanger B

Introduction. An unresolved item was identified to assess the continued capability of RHR Heat Exchanger B to perform its safety functions due to an ongoing fouling on the standby service water side of the tubes. This heat exchanger has not been tested for thermal performance in the last 2 years, and was not scheduled for cleaning until November 2008, despite an active fouling mechanism that continues to degrade the thermal performance of this component. This issue is unresolved for both significance and enforcement.

Description. As described above, the SSW has experienced fouling which degraded heat exchanger thermal performance for years. In the case of RHR Heat Exchanger B, thermal performance had degraded to the point of having only 0.6 percent positive margin to the design heat transfer capability under worst case conditions in 2005. The licensee increased the standby service water flow rate to these components in order to restore some operating margin (1.8 percent improvement) in July 2006, by reducing the flow rates to other components cooled by SSW.

Using the increased flow, a new analysis was performed to demonstrate operability of RHR Heat Exchanger B through January 2009. The team noted that this analysis also used criteria which were less conservative than the design basis considerations used in the original analysis. This analysis was based on the assumption that the rate of fouling was accurately known and would remain constant. However, the team identified that the licensee did not take action to verify that the fouling rate remained valid.

Based on this analysis, the licensee scheduled both RHR heat exchangers for cleaning. Maintaining the normal routine, the next outage (RF-15) would have been when RHR Heat Exchanger A was due for testing, so it was scheduled for cleaning instead. This heat exchanger was cleaned in March 2007. However, neither RHR heat exchanger was tested. The team noted that Generic Letter 89-13 specified that, if significant maintenance or cleaning was performed, then this heat exchanger must be tested three times to establish a performance baseline, but this was not done. The licensee also missed the opportunity to establish the effectiveness of the cleaning method, since this was the first time this component had ever been mechanically cleaned.

The licensee planned to clean RHR Heat Exchanger B in RF-16 in November 2008, when it would have normally been due for testing. The team noted that this schedule caused the heat exchanger with lower margin to be cleaned 18 months later than the one with somewhat better performance.

The team reviewed the thermal performance test data used in the licensee’s operability assessment. In essence, the fouling data was based on one high accuracy test on November 2, 2005, and one less accurate test on September 23, 2002. The two points established a line representing fouling rate. After correcting heat exchanger performance for the increased SSW flow rate, an extrapolation then was used to establish when there would be no positive margin. Since this was a few months after the cleaning, the licensee considered this cleaning schedule to be acceptable.

The team noted that the design capability of these heat exchangers was 113 percent of the required capacity under worst case accident conditions. Therefore, the licensee was willing to tolerate a loss of almost all performance margin prior to cleaning. The team noted that this philosophy was inappropriate, although it was consistent with the licensee’s program for thermal performance testing, MS-39.0, “Mechanical Standard for Thermal Performance Testing of Safety Related Standby Service Water Heat Exchangers,” Revision 6, Section 8.0. Specifically, this section did not require writing a condition report unless a step change in trend was noted, or if the projected fouling would cause the heat exchanger to exceed the design fouling before the next scheduled test. In effect, this procedure permitted operation with minimal positive margin before taking corrective action.

Analysis. The team was concerned that the licensee had not taken action to confirm that the thermal performance of RHR Heat Exchanger B remained adequate to remove worst case design basis heat loads. The projected fouling rate was based on limited data, some of which may not have been sufficiently accurate to rely on over a long period. Also, the licensee's historical data was not sufficient to provide high confidence that the fouling created a linear or predictable impact on heat transfer. Therefore, an unresolved item is being issued to further assess the capability of RHR Heat Exchanger B and determine whether a performance deficiency exists. In response to this concern, the licensee stated their intent to clean and/or conduct a thermal performance test of this heat exchanger prior to the onset of warm weather to ensure that the this component remained capable of removing the design basis heat load. The inspectors will review the results of the testing and/or cleaning when it is completed.

Enforcement. Additional information was needed to determine whether there were any violations of NRC requirements associated with this issue. This issue will be tracked as an unresolved item to verify that the fouling did not involve a loss of function:
URI 05000416/2007008-02, Verify continued operability of RHR Heat Exchanger B due to fouling.

1R07 Biennial Heat Sink Performance (71111.07B)

a. Inspection Scope

The team reviewed design documents (e.g., calculations and performance specifications), program documents, test procedures, maintenance procedures, test results, and corrective action documents. The team interviewed chemistry personnel, maintenance personnel, engineers, and program managers.

The team verified whether testing, inspection and maintenance, or the biotic fouling monitoring program provided sufficient controls to ensure proper heat transfer. Specifically, the inspectors reviewed heat exchanger test methods, test results from performance testing, inspection results, and chemical controls to limit fouling.

For the ultimate heat sink and its subcomponents, the team reviewed the heat sink to determine if it was free from clogging because of macrofouling and provided sufficient controls to ensure proper heat transfer. The inspectors reviewed; (1) heat exchanger test methods and test results from performance tests, (2) heat exchanger inspection and cleaning methods and results, and (3) chemical treatment for the SSW system and basins to control fouling. The team selected the following heat exchangers for this inspection:

- Residual heat removal heat exchangers
- Emergency diesel generator jacket water heat exchanger
- Containment purge compressor intercooler and bearing oil coolers

Inspection Procedure 71111.07B requires selecting two to three heat exchangers/heat sinks as inspection samples. The team completed three samples.

b. Findings

Introduction. A noncited violation of 10 CFR 50, Appendix B, Criterion XI, "Test Control," was identified because the licensee's thermal performance test procedures for the residual heat removal heat exchangers were inadequate to ensure the quality of the test results. Specifically, the test procedure failed to specify adequate prerequisites for minimum heat load and use of high-accuracy instrumentation. This resulted in test results used to meet commitments for the Generic Letter 89-13 test program which provided little useful information due to high inaccuracy.

Description. The team reviewed the licensee's trending of thermal performance test results for the RHR heat exchangers. The trends for each train were erratic and did not provide useful information. Between 1992 and 2005, the test results for RHR Heat Exchanger B had uncertainty values between ±37 percent and ±171 percent. The following issues were noted:

- Tests were conducted primarily with installed instrumentation, which typically would not have sufficient accuracy to conduct this type of test. Generic Letter 89-13 specifies that "an acceptable thermal performance test program should include necessary and sufficient instrumentation, although the instrumentation need not be permanently installed." Use of high accuracy test instrumentation is standard industry practice for this type of test.

- The heat loads used during the tests were not required by the test procedure to be as close as possible to design conditions. As a result, the tests were typically performed using 12 to 18 percent of the design heat loads, which would reduce the accuracy of the test results.

- Residual heat removal heat exchanger performance (fouling factor) was being trended by including worst-direction uncertainty applied to the test results. This introduced variable factors unrelated to heat exchanger thermal performance which could affect the reported trend. When this uncertainty was removed, at the request of the team, data scatter was improved considerably, and the expected performance trend (based on the fouling observed inside the heat exchangers) could be observed from the data.

- Grand Gulf Nuclear Station used Test Procedure 17-S-03-29, "GL 89-13 Thermal Performance Data Collection and Analysis," rather than the Entergy fleet procedure. Engineering personnel stated that the Entergy procedure was developed using the latest EPRI standards, while the Grand Gulf Nuclear Station procedure was not.

The combined effect of using test instrumentation with low accuracy and the low heat loads resulted in inaccurate test results.

The team determined that MS-39.0 was revised in 2006 to incorporate improved trending instructions, but the licensee had not gone back to correct the older data prior to this inspection.

Analysis: Failure to adequately test and trend the thermal performance of the RHR heat exchangers was a performance deficiency because it masked the actual thermal performance to the point where the licensee did not recognize the onset of fouling. The team determined that these heat exchangers began to experience fouling between 1997 and 1998, but this was not recognized within the licensee's heat exchanger thermal performance monitoring program. In the case of RHR Heat Exchanger B, the degraded performance was determined to be sufficient to make the fouling factor exceed the design value, necessitating compensatory action to be able to show continued operability. This was more than minor because, if left uncorrected, it could lead to a more significant safety concern in that the system could become fouled enough to prevent removing the required heat load without the licensee recognizing this condition. This finding affected the Mitigating Systems and Barrier Integrity Cornerstones, since this component was required for both decay heat removal and containment heat removal functions. In accordance with the Phase 1 SDP instructions, the significance was assessed using the Mitigating Systems Cornerstone, since this represented the dominant risk. This finding was determined to have very low safety significance (Green) during a Phase 1 SDP, since it was confirmed to not involve loss of the design heat removal capability.

Enforcement. Part 50 of Title 10 of the Code of Federal Regulations, Appendix A, General Design Criterion 46 requires in part that cooling water systems shall be designed to permit periodic functional testing to assure operability of the system under conditions as close to design as practical. Part 50 of Title 10 of the Code of Federal Regulations, Appendix B, Criterion XI, Test Control, requires in part that a test program shall be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed in accordance with written test procedures. Test procedures shall include provisions for assuring that all prerequisites for the given test have been met, that adequate test instrumentation is available and used, and that the test is performed under suitable environmental conditions.

The licensee used Test Procedure 17-S-03-29, "Generic Letter 89-13 Thermal Performance Data Collection and Analysis," Revisions 0 through 3, to specify perform thermal performance testing of the RHR heat exchangers. MS-39.0, "Mechanical Standard for Thermal Performance Testing of Safety Related Standby Service Water Heat Exchangers," Revision 0 through 6 was used for trending of the thermal performance test results.

Contrary to the above, Test Procedure 17-S-03-29 was inadequate to ensure that RHR heat exchanger thermal performance testing demonstrated that these components would meet their design requirements for heat transfer. Specifically, Test Procedure 17-S-03-29 test prerequisites did not specify a minimum heat load and instrument accuracy to ensure accurate test results. Because this violation was of very low safety significance and was entered into the licensee's corrective action program under CR 2008-04162, this will be treated as a noncited violation in accordance with the NRC Enforcement policy: NCV 05000416/2007008-03, Inadequate thermal performance testing of the residual heat removal heat exchangers.

4OA6 Management Meetings

On November 2, 2007, an onsite debrief was conducted on the last day of the onsite inspection. The tentative results of the inspection were discussed with Mr. D. Barfield and other members of the staff. The licensee confirmed that no proprietary information was handled during this inspection.

On December 13, 2007, a telephonic exit was conducted with Mr. R. Brian and other members of the staff to discuss the final categorization of one violation, and to request that the licensee provide additional information to justify the continued operability of RHR Heat Exchanger B through the planned cleaning date.

On January 23, 2008, a final telephonic exit was conducted following notification of the licensee's plan to clean and/or test RHR Heat Exchanger B prior to the onset of warm weather in order to ensure the continued operability of this heat exchanger.

Attachments:
1. Supplemental Information
2. Information request

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

D. Barfield, Director, Engineering
D. Bottemiller, Manager, Licensing
M. Causey, System Engineer
R. Collins, Manager, Operations
D. Coulter, Sr. Licensing Specialist
P. Different, Supervisor, Reactor Engineering
M. Jones, CA&A Technical Specialist
M. Gwynn, Manager, Emergency Preparedness
E. Harris, Manager, QA
A. Howard, Performance Engineer
M. Kruppa, Plant General Manager
J. Lassiter, Chemistry
G. Lee , CA&A Technical Specialist
S. Lee, Chemistry
S. Moore, Employee Concerns Coordinator
G. Swords, CA&A Technical Specialist
T. Thornton, Manager, Design Engineering
R. Tolbert, Chemistry
D. Wilson, Supervisor, Engineering
T. Worthington, Supervisor, Engineering
R. Wright, Supervisor, Engineering

NRC Personnel

S. Jones, Senior Engineer, NRR
M. Mitchell, Chief, CVIB, NRR
J. Tatum, Senior Engineer, SPBA, NRO

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000416/2007008-01	NCV	Failure to implement effective corrective action in response to significant heat exchanger fouling (Section 4OA2.e.1.(b)(1))
05000416/2007008-03	NCV	Inadequate Thermal Performance Testing of the Residual Heat Removal Heat Exchangers (Section 1R07)

Opened

005000416/2007008-02	URI	Verify Continued Operability of RHR Heat Exchanger B Due to Fouling. (Section 4OA2.e.1.(b)(2))

LIST OF DOCUMENTS REVIEWED

Procedures

EN-OP-104, Operability Determinations, Rev. 2
EN-LI-102, Corrective Action Process, Rev. 10
EN-LI-118, Root Cause Analysis Process, Revision 7
EN-LI-119, Apparent Cause Evaluation (ACE) Process, Revision 7
EN-OE-100, Operating Experience Program, Rev.2
EN-RP-104, Personnel Contamination Events, Revision 1
EN-RP-203, Dose Assessment, Revision 1
EN-RP-203, Dose Assessment, Revision 0
EN-OE-100, Operational Experience Program, Revision 2
EN-RP-109, Hot Spot Program, Revision 0
01-S-02-3, Preventive Maintenance Program, Revision 111
08-S-03-10, Chemistry Sampling Program, Revision44
08-S-03-14, Chemistry Additions to Plant Systems, Revision 22
08-S-03-28, SSW Emergency Water Treatment Guide, Revision 0
08-S-04-120, Chemistry Instruction, Chemistry Evolutions at SSW Safety Related, Revision11

Drawings

E-1267-019, Safeguards Switchgear & Battery Room Air Handling Unit Supply Fan B001A-A, Rev. 3
M-1061A, Standby Service Water System, Rev. 62
M-1061B, Standby Service Water System, Rev. 48
M-1061C, Standby Service Water System Rev.36
M-1061D, Standby Service Water System, Rev. 39

Condition Reports

2001-0798	2005-4827	2006-2554	2006-3397	2006-3445	2006-3577
2003-0039	2007-0958	2007-0959	2007-4123	2007-4240	2007-4606
2005-3749	2007-4717	2007-4763	2007-4767	2007-4770	2007-4780
2003-0844	2007-4783	2007-4784	2007-4787	2007-4792	2007-4795
2003-0884	2007-4822	2007-4862	2007-5120	2004-0283	2004-4443
2003-1066	2004-4538	2005-0544	2005-1007	2005-1803	2005-1854
2005-1865	2005-1872	2005-3016	2005-3642	2005-4202	2005-4552
2006-1178	2006-1551	2006-1955	2006-2653	2006-2951	2006-4870
2007-0014	2007-0033	2007-0174	2007-0378	2007-0419	2007-0554
2007-0825	2007-0929	2007-1098	2007-1156	2007-1159	2007-1262
2007-1434	2007-1777	2007-1468	2007-1509	2007-1829	2007-1870
2007-1955	2007-2135	2007-2113	2007-2168	2007-2169	2007-2274

2007-3384	2007-3403	2007-3425	2007-3427	2007-3434	2007-3436
2007-3449	2007-3461	2007-3461	2007-3468	2007-3477	2007-3477
2007-3573	2007-3576	2007-3579	2007-3657	2007-3736	2007-3739
2007-3757	2007-4335	2007-4778	2007-4782	2007-4835	2003-0231
2003-0039	2006-3445	2005-3749	2006-3520	2006-1260	2004-3778
2007-2521	2006-0343	2007-3270	2006-0260	2007-3264	2006-2875
2006-0864	2005-3749	2006-0952	2003-2527	2006-0834	2005-1766
2006-4591	2006-0776	2007-2446	2007-0619	2007-0266	2003-2527
2007-3318	2007-3068	2007-3335	2007-4453	2005-3167	2007-3311
2005-3637	2007-1142	2005-4204	2007-2521	2006-4591	2005-3154
2004-3085	2006-2468	2006-0952	2006-2770	2006-0864	2006-2782
2006-0834	2005-4435	2006-0852	2006-0108	2005-4985	2007-3911
2007-2054	2007-3380	2006-2550	2007-4412	2005-1268	2007-0266
2005-3462	2005-4474	2007-0739	2006-0361	2007-4860	2008-0412

Operability Evaluations

2001-0798	2003-0039	2005-3749	2005-4827	2006-3397	2006-3445
2007-4123	2007-4240	2007-4606	2007-4767	2007-4770	2007-4783
2007-4784	2007-4862	2007-4822	2007-5120	2005-3123	2005-3167
2005-1354	2005-3167	2005-3637	2005-4001	2005-4204	2005-4474
2007-0266	2007-1142				

Root Cause Evaluations Reviewed:

2005-00544, “Reactor SCRAM due to Animal Intrusion”, 2/23/2005

2005-01007, “Cask Shipped from Grand Gulf with One of Six Reinforcing Blocks Not Installed”, 04/11/2005

2005-1803, “Radial Well Discharge Pipe Removal Without Proper Tagging Boundary”, 5/25/2005

2006-1178, “Reactor Feed Pump Trip”, 4/17/2006

2007-2936, “Less than 100% Pass Rate on 2007 NRC Initial Written Examination”, 6/27/2007.

2006-1551, “Apparent Inattentiveness Observed in Security Officers on Post”, 4/24/2006

2006-1955, “Exhaust Valve Failure on Standby Diesel Generator (SDG) 11", 6/14/2006

2006-4870, “1H22-P172 Disturbance”, June 12, 2007

2007-00378, “Division 1 Emergency Diesel Generator Jacket Water High Temperature”, August 7, 2007

2005-3016, “Failure of a Newly Installed Corrosion Probe in a Corrosion Rack Resulted in a Leak in the Component Cooling Water System,” 9/13/2005

2005-1803, “Failure of Turbine 1st Stage Pressure Sensing Line”, 11/14/2005

2005-4827

2007-2936

Apparent Cause Quality and Training:

Course Records for GGRP-ESPP-LI119, “Apparent Cause Evaluation Process”
EN-LI-102, “Corrective Action Process,” Rev. 10
EN-LI-102, “Corrective Action Process,” Rev. 11
EN-LI-119, “Apparent Cause Evaluation Process,” Rev. 5
EN-LI-119, “Apparent Cause Evaluation Process,” Rev. 6
EN-LI-119, “Apparent Cause Evaluation Process,” Rev. 7

Apparent Cause Evaluations Reviewed:

2003-0039	2005-3749	2005-4827	2006-1022	2006-1461	2006-1477
2006-4825	2006-3500	2006-4762	2006-4825	2007-0056	2007-0402
2007-1061	2007-1338	2007-2323	2007-3311	2007-0033	2007-0419
2007-0014	2005-4202	2006-2951	2005-1713	2005-1865	2003-0039
2005-3749	2006-0952	2007-0619			

Self-assessments Reviewed:

Grand Gulf Station Follow-Up Corporate Assessment, dated May 31, 2007

Assessment of the Problem Identification and Resolution (GLO 2007-0089) dated May 4, 2007

Licensed operator Requalification training Inspection Assessment (GLO 2007-0122)

Focuses Self Assessment: Effectiveness of OJT Enhancement training (GLO 2007 0134)

Assessment of the Assessment Process (GLO 2007-0020)

Snapshot Assessment on CAP Performance Indicators (GLO 2007-0128)

Snapshot Assessment - Initial Licensed operator Training LOT 309 Class Preparation (GLO-2007-0139

Snapshot Assessment/Benchmark on GGNS ESP training Learning Objectives (GLO 2007-0091)

Calculations:

2.2.15, Determine Allowable Fouling Factor for SSW Components, Revision A

Miscellaneous Documents:

Top 10 Equipment Issues List, dated 7/12/07

System Performance Indicators Report, dated 9/27/07

List of deferred preventive maintenance items, dated 10/23/07

Radiation Protection Shift Narrative Logs for July 2007

UFSAR Section 7.6, “All Other Instrumentation Systems Required for Safety” Rev. 7
ER-GG-2006-0161-000, “Use of Ultra Low Sulfur Diesel Fuel”, Revision 0

LER 2006-001-00, “Division 1 Diesel Generator Exhaust Valve Failure”, Revision 0

IV. Operating Experience Review:

Self-Assessments:

LO-ELO-2006-00004-CA-00042, “GGN Assessment Station Use of Operating Experience”, November 2006

LO-ELO-2004-00179, “GGN Station Use of Operating Experience”, December 2004

GGN Response to Information Notices:

LO-OPX-2006-00400
LO-OPX-2005-00255
LO-OPX-2005-00241
LO-OPX-2005-00243
LO-OPX-2004-00249
LO-OPX-2003-00370
LO-OPX-2006-00442

Information Notices:

IN 2005-24, Non-conservatism in Leakage Detection Sensitivity, August 3, 2005

IN 2005-19, Effect of Plant Configuration Changes on the Emergency Plan, July 18, 2005

IN 2005-20, Electrical Distribution System Failures Affecting Security Equipment, July 19, 2005

IN 2004-19, Problems Associated with Back-Up Power Supplies to emergency Response Facilities and Equipment, November 4, 2004

IN 2003-17, Reduced Service Life of Automatic Switch Company (ASCO) Solenoid Valves with Buna-N Material, September 29, 2003

IN 2006-21, Operating Experience Regarding Entrainment of Air into Emergency Core Cooling and Containment Spray Systems, September 21, 2006

IN 2006-24, Recent Operating Experience Associated with Pressurizer and Main Steam Safety/Relief Valve Lift Setpoints, November 14, 2006

IN 2004-19, Problems Associated with Back up Power Supplies to Emergency Response Facilities and Equipment

<u>NCV Effectiveness Reviews</u>

NCV 2005004-02 (CR 2005-03642)
NCV 2005008-02 (CR 2005-01865 and CR 2005-01854)
NCV 2005008-01 (CR 2005-01872)
NCV 2005009-03 (CR-2004-04443)
NCV 2007002-01 (CR-2007-00554)
Licensee-Identified NCV of TS 5.4.1(a) (CR 2007-00174)

<u>CRD FCV Degradation Review</u>:

ER-GG-2006-0124-000 Rev. 0, “Repair Valve 1C11F002B”

ER-GG-2006-0137-000 Rev. 0, “Replace Valves 1C11F002A/B”

ER-GG-2007-0003-001 Rev. 0, “Revise Base ER to Permit the Downstream Isolation Valve to be Open During welding”

ER-GG-2007-0067-000 Rev.0, “Evaluate Not Replacing the 1C11F002A/B Valves in RF15"

MPRC Subcommittee Meeting Minutes, September 5, 2006

<u>Condition Reports:</u>

2003-0892	2005-4334	2006-4823	2006-2117	2007-0956	2007-0991
2007-2998	2007-5026				

<u>Human Performance Review</u>:

EN-LI-121, “Entergy Trending Process,” Rev. 6
EN-HU-101, “Human Performance Program,” Rev. 4
EN-HU-102, “human Performance Tools,” Rev. 1
EN-HU-103, “Human Performance error reviews,” Rev. 0
EN-HU-104, “Engineering Task and Rigor,” Rev. 1
EN-HU-106, “Managed Defenses,” Rev. 2

CR 2007-2323

Human Performance Steering Committee Meeting Minutes, June 2007

<u>Drywell Purge Compressor Review:</u>

ER-GG-2006-0227-000, “Drywell Purge Compressor Oil Cooler Anodes,” Rev 0

Vendor Manual 460003466, “Compack SC-6 Single Stage Centrifugal Compressor”
WO 88296

Condition Reports:

2006-04825 2006-04762 2006-04738 2006-04753
Work Request 88915

SCWE Review:

EN-PL-100, Nuclear Safety and Management Expectations, Rev. 0

EN-PL-187, Safety Conscious Work Environment Policy, Rev. 0

EN-PL-190, Maintaining a Strong Safety Culture, Rev. 1

FCBT-ADM-SCWE, Training on Safety Conscious Work Environment, Rev. 2

Employee Concerns Program brochure

Methods and Contacts for Raising safety Concerns

FCBT-ADM-ECPMGT, Training on Handling Employee Concerns for Managers/Supervisors, Rev. 0

ECP Newsletter, dated March 2007

2006 Nuclear Safety Cultural Assessment, March 2006

2006 Nuclear Safety Cultural Assessment Presentation Slides, June 7, 2006

2006 Nuclear Safety Cultural Assessment Action Plan

5 Year Review of SSW:

Power Generation Technologies TIN 2005-1124, Rev.0 (Heat Removal Heat Exchangers Q1E12B001B/2B Thermal Performance Data and Uncertainty Analysis).

17-S-03-29, GL 89-13 Thermal Performance Data Collection and Analysis, Rev. 3

STI-GGNS-2005-002, RHR B Heat Exchanger Protocol Test, 10/20/05

Nalco Analytical Resources, ND0503996, Deposit Analysis Report, Dated Sep 26, 2005

Generic Letter 89-13, Service Water System Problems Affecting Safety Related Equipment

Work Order 00114595,

Condition Reports:

2005-3123	2005-3167	2005-1354	2005-3167	2005-3637	2005-4001
2005-4204	2005-4474	2007-0266	2007-1142		

Grand Gulf PI&R Inspection Document Request

This inspection will cover the period March 26, 2004 through November 2, 2007. Unless otherwise stated, all requests should be limited to this time period.

Please provide the following as soon as possible in electronic form, if practical, but not later than September 21, 2007:

1. Procedures for implementing all problem-identification and resolution processes. This would include, but not be limited to, Condition Report reporting and resolution, assessment of industry operating experience, operability assessment and documentation, root cause assessment, event assessment, addressing violations of NRC requirements, cause evaluations, etc.

2. Self assessment documents:

    a. Copies of all internal and external self-assessments and QA audits performed since November 2005. This should include department-level assessments.

    b. Copies of all trend reports and corrective action effectiveness reports associated with the corrective action process generated within the last year (e.g. equipment trends, trending of CR's, etc.).

    c. Copies of procedures used to conduct trending of equipment failures, and other trend analyses.

    d. Copy of the latest system health report summary for all systems monitored.

    e. A copy of any safety culture assessments performed since March 2005, and any documents that describe the site plan to address the results.

    f. A copy of the most recent corrective action program metric results.

3. Procedures and/or charter documents describing responsibilities of the Corrective Action Review Board.

4. List of all current maintenance rule (a)(1) SSCs, including time it entered into a(1) and what caused it to go into (a)(1) status.

5. A copy of the current Top 10 Equipment Reliability Issues list.

6. Operating Experience items:

    a. A list of all industry events, generic communications, Part 21 reports, or other operating experience documents reviewed by the station operating experience program since March 2005.

    b. A list of CR's generated to assess any of those items.

c. Copies of procedures for implementing assessments of industry operating experience from any sources (e.g. NRC, INPO, Part 21 reports, vendor technical bulletins, etc.).

7. Cause evaluation documents:

   a. A copy of all root cause evaluations performed since March 2005.

   b. A summary list of apparent cause evaluations during the same period.

   c. Copies of the procedures used to conduct root cause evaluations and apparent cause evaluations.

8. Operability assessment documents:

   a. Copies of procedures governing operability assessment in accordance with Information Notice 2005-20.

   b. A list (with document number and description) of all items classified as degraded or non-conforming in accordance with Information Notice 2005-20 that are currently open.

9. The post-trip assessment packages and restart readiness reviews for any trips since March 2005.

10. A list of meetings (times and locations) for the periods of onsite inspections for the following:

    Onsite Review Committee (OSRC)
    CR Review Committee (CRG) screening meeting
    Corrective Action Review Board (CARB)

11. A list of preventive maintenance items (number and title) for safety related equipment which are currently:

    a. Past their due date.
    b. Have no due date assigned.

12. Copies of all CR's written to address problems or improvements identified as a result of emergency preparedness drills or exercises since March 2005.

13. A copy of any operating experience review and actions to address the following NRC Information Notices:

    a. IN 2007-26, Use of Combustible Epoxy Floor Coatings

    b. IN 2006-21, Ultra-Low Sulfur Diesel Fuel

    c. IN 2005-24, Containment Leakage Detection Sensitivity

d. IN 2005-19, Effect of Plant Configuration Changes on the Emergency Plan

e. IN 2005-20, Electrical Distribution System Failures Affecting Security Equipment

f. IN 2004-19, Backup power Supplies to Emergency Response Facilities and Equipment

g. IN 2003-17, Reduced Life for ASCO SOVs

14. Documentation of corrective actions for the following inspection items:

NCV 05000416/2005004-02, Failure to Control a High Radiation Area with Dose Rates Greater Than One Rem per Hour CR-GGN-2005-03642

NCV 05000416/2005008-02, Inadequate alternative shutdown procedure. Condition Report 2005-01865.

FIN 05000416/2005008-01, Inadequate Fire Drill Critique. CR 2005-01872.

NCV 05000416/2006002-04, Untimely Corrective Actions Associated with Condensate Storage Tank Level instrumentation. CR-GGN-2006-1096

NCV 05000416/2005009-03, Inadequate corrective actions to Address Degraded Control Room Air Conditioning Unit. CR-GGN-1999-0742, CR-GGN-2004-4443, and CR-GGN-2004-04443.

NCV 05000416/2006004-02, Failure to Monitor Containment Pool Liner Leakage per Operator Rounds. CR-GGN-2006-3500

NCV 05000416/2006005-01, Failure to Follow Station Procedures for Conducting Maintenance Activities. CR-GGN-2006-4474

NCV 05000382/2006008-01, Inadequate Test Control Program for Standby Service Water-Cooled Heat Exchangers. Condition Reports 2006-00834, 2006-00852, 2006-00864, 2006-00952, 2006-00959, and 2006-00960

NCV 05000416/2006010-01, Inadequate Corrective Actions for SDG Cylinder Head Cracks. CR-GGN-2006-1955

NCV 05000416/2007006-01, Failure to Prevent Recurrence of High Standby Diesel Generator Temperatures. CR-GGN-2007-0378

NCV 05000416/2007006-04, Inadequate Operability Evaluation for EDG. CR-GGN-2007-2256

NCV 05000416/2007002-01, Inadequate Operability Evaluation for a degraded switchgear ventilation system. CR-GGN-2007-0554.

NCV 05000416/2007002-03, Failure to Follow Procedural Guidance and Radiation Work Instructions While Supporting Radiography Operations. CR-GGN-2007-01582

NCV 05000416/2007002-07, Failure to Identify and Correct Standby Service Water System Leakage. CR-GGN-2006-4762

NCV 05000416/2007002-06, Failure to Follow Procedure Resulting in Isolation of Switchgear Room Ventilation. CR-GGN-2006-4394.

Licensee-Identified NCV of TS 5.4.1(a). OE review determined that a station battery intercell resistance measurement surveillance had been performed incorrectly. CR-GGN-2007-0174.

Licensee-Identified NCV of TS 5.4.1(a) for failure of maintenance technicians to follow procedure and tighten bolts in a core spray pump breaker. CR-GGN-2006-4458.

Licensee-Identified NCV of TS 5.4.1(a) for failure of operators to notify reactor engineering when jet pump flow was low. CR-GGN-2007-1061 and CR-GGN-2007-1071.

NCV 05000416/2007003-03, Inadequate Foreign Material Controls During Reactor Feed Pump Maintenance. CR-GGN-2007-2158.

15. Copies of CR's, cause evaluations, actions to address the problems, and supporting information on main feedwater controller problems. These apparently contributed to a plant trip in 2006 and a feed pump trip in 2007.

16. Copies of CR's, cause evaluations, actions to address the problems, and supporting information on Emergency Operating Facility diesel generator. This should include, but not be limited to, reliability problems and the possibility that it may be undersized for expected loads.

17 - 19. Deleted.

20. Copies of CR's and supporting information on relief valves not lifting at their required setpoint, any cause evaluations, and actions to address the problem.

21. The following documents related to operability evaluation-type issues:

CR-GGN-2005-1429, Reactor core isolation cooling exhaust valve operation
CR-GGN-2005-2355, Reactor core isolation cooling trip/throttle valve
CR-GGN-2005-2968, Reactor recirculation system flow control Valve A
CR-GGN-2005-3167, Standby service water system fan motors
CR-GGN-2005-3290, Standby service water system Pump A discharge valve
CR-GGN-2006-00587, Standby gas treatment system failed to maintain the required negative pressure in the auxiliary building
CR-GGN-2006-1577, Trip of Division 2 emergency diesel generator
CR-GGN-2006-03991, Degraded air flow in the fuel pool cooling and cleanup room cooler

CR-GGN-2006-04198, Reactor water cleanup containment isolation valve failure
CR-GGN-2006-04660, Reactor core flow degradation
CR-GGN-2007-2255, Suspected cause of EDG high temperature not re-evaulated when disproved as cause.
CR-GGN-2007-0378, Division 1 EDG failure to run
CR-GGN-2007-0660, nonconforming Division 1 EDG thermostatic control valve
CR-GGN-2007-0927, residual heat removal Train C leakage
CR-GGN-2007-0174, higher than expected Division 2 battery intercell resistance measurements
CR-GGN-2007-2955, failure of temperature switch for RCIC room isolation
CR-GGN-2007-1840, Division I EDG jacket water leak
CR-GGN-2007-2060, Nitrogen in hydraulic control units
CR-GGN-2007-2828, Valve E12F053B leaking past seat

22. A summary of all CRs written during the evaluation that relate to troubleshooting of plant equipment.

23. A copy of the Human Performance Improvement Plans and status of progress made on it.

24. A 5-year review of problems associated with the safety service water system will be performed.

    a. Please provide a summary list of all CR's written since October 2002 that relate to this system, to include CR number, date, and subject.

    b. Please provide a summary list of all CR's written since October 2002 that involve fouling of heat exchangers or room coolers, to include CR number, date, and subject.

    c. Please provide a summary list of all CR's written since October 2002 that involve room cooler fan problems, to include CR number, date, and subject.

    d. Please provide a copy of any procedures that describe or control chemistry control for the SSW system and the ultimate heat sink pools.

    e. Please provide a list of any temporary modifications installed that affect SSW system components, or operation of the system or its cooled loads.

    f. Please provide a list of any planned permanent modifications installed that affect SSW system components, or operation of the system or its cooled loads.

25. Workaround documents:

    a. A copy of procedures for identifying, documenting and correcting workarounds in the broadest sense of the term (many stations have several categories for workaround-type issues)

    b. A copy of the latest issues being tracked in these processes.

c. A copy of CR’s or other documents relating to workarounds.

26. Copies of any condition reports documenting possible lube oil contamination, use of the wrong lube oil, or out of specification lube oil analysis results.

27. Summary of ARs documenting inadequate procedures.

28. Copies of CR’s associated with control rod drive flow control valves.

29. Copies of CR’s associated with fire pumps and the fire water jockey pump.

30. Copies of CR’s documenting problems with plant modifications, temporary or permanent.

31. Copies of any CR’s, cause evaluations, and corrective actions to address problems with the initial licensed operator exam submitted in 2005, including understanding of the qualitative attributes of NRC written examination questions and, to a lesser extent, the examination development process, as described in NUREG-1021.

32. Copies of training material, pamphlets, or other material provided to employees and contractors at the site concerning the station’s nuclear safety concerns program or similar program. Please include explanation of the periodicity of such training or handouts.

33. Copy of CR-GGN-2006-2329, untimely corrective actions for temperature sensor contributed to reactor recirculation pump trip.

34. Copy of CR-GGN-2006-2910, a mobile security barrier in the vicinity of the low pressure coolant injection Train B instrumentation rack in the auxiliary building was not properly secured per Procedure 01-S-07-43, “Control of Loose Items, Temporary Electrical Power, and Access to Equipment,” Revision 4.

35. A list of condition reports documenting failure to follow procedures.

36. Copy CR-GGN-2006-03605 on remediation prior to returning the crew to duty.