U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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Licensee:	Tennessee Valley Authority
Facility:	Browns Ferry Nuclear Plant, Units 1, 2, & 3
Location:	Corner of Shaw and Browns Ferry Roads Athens, AL 35611
Dates:	March 21 - May 1, 1999
Inspectors:	W. Smith, Senior Resident Inspector J. Starefos, Resident Inspector E. DiPaolo, Resident Inspector D. Jones, Reactor Engineer (Section R1.1) J. Coley, Reactor Engineer (Section M1.3)
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Enclosure

EXECUTIVE SUMMARY

Browns Ferry Nuclear Plant, Units 1, 2, and 3
NRC Inspection Report 50-259/99-02, 50-260/99-02, 50-296/99-02

This integrated inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 6-week period of resident inspection. In addition, the licensee's inservice inspection and radiological controls programs were inspected.

Operations

- Operator performance in support of the Unit 2 refueling outage was acceptable. Prior to the outage, when a high pressure coolant injection (HPCI) actuation logic circuit wire was found loose, the operators conservatively declared the system inoperable and promptly reported the event to the NRC pursuant to 10 CFR 50.72 (Section O1.1).

- Proper plant conditions were established to minimize the impact of a plant transient prior to troubleshooting voltage fluctuations on the 3A recirculation pump motor-generator (MG) voltage regulator. After the MG tripped, an off-shift senior reactor operator was appointed to independently verify that all required actions were performed. This was a good practice for the abnormal condition. Operators responded well to the transient and no problems were identified with the transition to single loop operation (Section O1.2).

- The Unit 2 refueling outage was well-planned and executed, notwithstanding unexpected emergent work. Coordination and communications between plant departments was excellent and was an essential contributor to the timely implementation of the outage schedule (Section O1.3).

- The licensee demonstrated poor system configuration controls and attention-to-detail by failing to remove all of the foreign material exclusion covers from the inlets of the main steam relief valve discharge pipe vacuum breakers prior to the previous Unit 2 post-outage drywell closure, as required by procedures. The safety significance was reduced, however, because the affected relief valves were not rendered inoperable. A non-cited violation (NCV) was identified for failure to follow procedures (Section O2.1).

- During shutdown cooling lineup checks for the Unit 2 refueling outage, precautions intended to control temperature on the common service water discharge piping of the residual heat removal heat exchangers were not followed by operators. However, the design temperature of the piping was not exceeded. An NCV was identified for failure to follow procedures (Section O4.1).

Maintenance

- Surveillance tests observed during the inspection period were generally performed in a professional and safe manner. Good coordination and communications were demonstrated during the C diesel generator emergency load acceptance test. The complex test required the coordination of numerous personnel in different plant areas to perform plant manipulations and gather test data. The evolution was completed without problems (Section M1.1).

- Work activities observed were conducted in a well-planned and professional manner. Workers were familiar with the assigned tasks. Engineering support of the maintenance, where applicable, was good. The engineers frequently monitored the work and were knowledgeable of the equipment. Proper radiological controls were maintained, where required (Section M1.2).

- Inservice examination activities observed were performed in a thorough manner by knowledgeable examiners using approved procedures (Section M1.3).

- During review of periodic surveillance functional testing and maintenance of system hydraulic snubbers during the Unit 2 outage, as-left acceptance criteria were exceeded for a residual heat removal system snubber. However, the snubber was signed off as satisfactory, based on an inappropriate, undocumented evaluation. An NCV was identified for failure to follow procedures (Section M3.1).

- The licensee's actions to resolve the Conax conduit assembly problems associated with grounds identified in the Unit 3 main steam isolation valve limit switch circuits were executed in a thorough manner (Section M8.1).

Engineering

- The modeling assumptions for most turbine trip transients in the licensee's core reload analysis, General Electric Standard Application for Reactor Fuel (GESTAR II), NEDE-24011-P-A, incorrectly assumed that the associated transient pressure response was controlled by the turbine stop valves vice the turbine control valves. However, the operating limit minimum critical power ratio was not effected for the current operating cycles of Units 2 and 3 (Section E1.1).

- An NCV was identified in connection with the licensee's failure to perform a safety evaluation in support of work/testing on the HPCI system with the system being operable, as required by plant procedures and 10 CFR 50.59 (Section E1.2).

- The licensee implemented a thorough and comprehensive effort to validate and update the contents of the Updated Final Safety Analysis Report (Section E8.1).

Plant Support

- The licensee was properly monitoring and controlling personnel radiation exposure during the Unit 2 Cycle 10 refueling outage and posting area radiological conditions in accordance with 10 CFR Part 20. Personnel entering the radiologically controlled area were adequately briefed on radiological hazards and protective measures. Maximum individual radiation exposures were controlled to levels which were well within the regulatory limits for occupational dose specified in 10 CFR 20.1201(a). The licensee was generally successful in meeting established ALARA (as low as reasonably achievable) goals, in that eight of ten goals were met during 1994 through 1998 (Section R1.1).

Report Details

Summary of Plant Status

Unit 1 remained in a long-term lay-up condition with the reactor defueled.

Unit 2 operated at or near maximum available power until April 11, 1999, when a plant shutdown and cooldown was performed to commence the Unit 2 Cycle 10 (U2C10) refueling outage (RFO). As of the end of the inspection period, the unit was in Mode 4 and making preparations for startup as outage activities neared completion.

Unit 3 operated at or near full power with the exception of brief reductions in power to adjust control rods and perform routine maintenance. Also, on April 18, 1999, power was reduced and operators placed the unit in single recirculation loop operation due to problems associated with the 3A recirculation pump motor-generator voltage regulator. Subsequent to troubleshooting and repairs, dual loop operation was resumed on April 21, 1999, and the unit was returned to full power (see Section O1.2).

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Overall operator performance was acceptable during this inspection period which included additional work associated with the outage. On April 8, 1999, the high pressure coolant injection (HPCI) system became inoperable because of a loose wire found in the power supply pathway for the system initiation logic circuit. This condition had the potential to prevent automatic initiation of the system if called upon to perform its intended safety function. The operators conservatively declared the system inoperable and reported this to the NRC in accordance with 10 CFR 50.72 as a four-hour non-emergency event where a single train system designed for accident mitigation was inoperable (Event No. 35562). The operators provided timely and safe support during this period of heavy outage activity. The ramping down of power and subsequent manual scram on April 11, to shut down the unit for the refueling outage was well executed. There was an operator error identified during the cooldown process that is described in Section O4.1 below.

O1.2 Unit 3 Single Loop Operation

a. Inspection Scope (71707)

The inspectors observed activities associated with failure of the 3A recirculation pump motor-generator (MG) voltage regulator and assessed operator response.

b. Observations and Findings

On April 20, 1999, the inspectors observed troubleshooting activities on the 3A recirculation pump MG voltage regulator. The MG had been experiencing periodic

voltage fluctuations. Because the on-going troubleshooting activities were considered high risk, plant conditions (control rod line and reactor recirculation flow) were established to minimize the impact of a plant transient if the MG inadvertently tripped. This was performed in order to minimize the likelihood of entering Region I or II on the power-flow map. Prior to commencing troubleshooting activities, field voltage fluctuations increased and the MG subsequently tripped. The inspector also observed activities in the control room and verified that operators performed all required actions in response to the transient. The inspectors noted that the shift manager appointed an off-shift senior reactor operator to independently verify that all required actions were performed. This was a good practice for the abnormal condition.

Following entry into single loop operation, the inspectors reviewed portions of Surveillance Procedure 3-SR-3.4.1(SLO), Reactor Recirculation System Single Loop Operation, to verify that the operating limit minimum critical power ratio (OLMCPR) values were updated in the process computer for single loop operations consistent with the Core Operating Limits Report.

c. Conclusions

Proper plant conditions were established to minimize the impact of a plant transient prior to troubleshooting voltage fluctuations on the 3A MG voltage regulator. After the MG tripped, an off-shift senior reactor operator was appointed to independently verify that all required actions were performed. This was a good practice for the abnormal condition. Operators responded well to the transient and no problems were identified with the transition to single loop operation.

O1.3 Unit 2 Refueling Outage Observations (71707,62707,71750)

The inspectors monitored the licensee's activities associated with the U2C10 RFO. This included periodic attendance at production meetings, plant tours, and outage schedule review.

The RFO schedule was well-planned and executed despite unexpected emergent work. Coordination and communications between plant departments (operations, maintenance, engineering, etc.) was excellent and was considered an essential contributor to the timely execution of the outage schedule. For example, outage briefings during operations shift turnover were informative and detailed activities for the upcoming shift.

During the inspection period, the inspectors toured areas which are normally inaccessible during power operations. This included the main steam line tunnel, the drywell, and the suppression pool. Material condition was good with only minor deficiencies noted by the licensee and the inspectors which were subsequently corrected. The inspectors monitored various outage activities in addition to the specific areas described in the inspection report. The inspectors observed good foreign material exclusion (FME) controls. Minor problems with radiological work practices were observed. Housekeeping was generally good and was improved over previous outages. Site management had reinforced housekeeping expectations throughout the outage.

O2 Operational Status of Facilities and Equipment

O2.1 Protective Covers Found on Main Steam Relief Vacuum Breakers

a. Inspection Scope (71707,37551)

Following the Unit 2 shutdown for the RFO and opening of the drywell, the licensee found FME covers already installed on two of the 10-inch vacuum breakers for the main steam relief valves (MSRV). Because of the potential safety-significance of this issue, the inspectors monitored the licensee's actions and evaluated the impact on plant safety.

b. Observations and Findings

On April 12, 1999, while performing Surveillance Instruction 2-SI-3.2.11, Main Steam Relief Valve Discharge Pipe Vacuum Breaker (Check Valve) Test, the licensee identified FME covers that appeared to have been left on the inlets for MSRV discharge pipe vacuum breaker check valves 2-CKV-10-529 and 2-CKV-10-531. This raised a question as to the operability of the affected MSRVs, 2-PCV-001-34 and 2-PCV-001-42, respectively. The licensee initiated Problem Evaluation Report (PER) 99-004350-000 and formed an Incident Investigation Team (IIT) to confirm the condition and determine causes and corrective actions.

Engineering promptly generated Technical Operability Evaluation (TOE) 2-99-101-4350, dated April 12, 1999, to evaluate past operability of the MSRVs. The inspectors reviewed the TOE and noted that the MSRVs were considered operable on the basis that, in short, (1) all of the MSRVs were tested successfully after the previous outage, (2) there is a redundant, 2-1/2 inch vacuum breaker installed on each MSRV discharge pipe, and (3) the MSRV discharge pipes were substantially strengthened as part of the Long Term Torus Integrity Program. This modification added pipe supports, installed improved spargers, and installed the 10-inch vacuum breakers to supplement the original design 2-1/2 inch vacuum breakers. The inspectors found no problems with the TOE and its conclusion that, with the two 10-inch vacuum breakers covered, all MSRVs and their discharge pipes were capable of performing their intended safety functions.

The IIT conducted a thorough investigation and issued an event report, which the inspectors reviewed. The IIT determined that the covers were installed for the duration of the previous Unit 2 operating cycle; however, the IIT analysis indicated that the MSRVs were not rendered inoperable, which was consistent with the above referenced TOE. As part of the extent of condition, the IIT reviewed all other activities which require temporary materials or equipment to be brought into the drywell, and were not associated with a specific work document. This information was used in developing corrective actions.

The IIT concluded the vacuum breaker covers were left installed following the last Unit 2 RFO because of human error, i.e., different departments installed and removed the covers for the last Unit 2 outage, and the work order (WO) did not provide enough detail

for the workers. In addition, Procedure 2-GOI-200-2, Revision 15, Drywell Closeout, did not specifically list each vacuum breaker so that the FME covers could be individually accounted for. Consequently, the two 10-inch vacuum breakers, which were difficult to see and gain access to, were missed.

Corrective actions included issuance of a WO for the current outage, to more rigorously control the removal of the vacuum breaker covers. Also, as directed by the plant manager, a team was set up to develop a drywell closeout procedure that is comprehensive enough to assure there is not a repeat problem with any other safety system or component in the drywell.

The inspectors noted that notwithstanding the fact that the procedures in effect during prior closure of the Unit 2 drywell were not specific enough to account for each vacuum breaker, both Procedure 2-GOI-200-2 and WO 97-007095-000 provided barriers to ensure that the vacuum breakers were not left covered during plant operation. Procedure 2-GOI-200-2, Step 1.19 stated, "Each SRV discharge line drywell to suppression chamber vacuum breaker free of debris." WO 97-007095-000 contained instructions to install Herculite covering on the MSRV vacuum breaker check valves with a provision for sign off, and then a sign-off for closure of the WO stating that the foreman will ensure all covers and scaffolding installed inside the drywell under this WO are removed prior to closure. These procedures were not followed, as evidenced by the FME covers being left on two vacuum breakers after closure of the Unit 2 drywell in October 1997.

Failure to comply with Procedure 2-GOI-200-2 and WO 97-007095-000 is a violation of Technical Specification (TS) 5.4.1, which requires procedures to be implemented as recommended in Regulatory Guide 1.33, Revision 2, Appendix A, for operating and maintenance activities. This Severity Level IV violation is being treated as a non-cited violation (NCV), consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as PER 99-004350-000, and is identified as NCV 50-260/99-02-01, Failure to Remove MSRV Vacuum Breaker Covers.

c. <u>Conclusions</u>

An NCV was identified for failure to follow procedures. The licensee demonstrated poor system configuration controls and attention-to-detail by failing to remove all of the FME covers from the inlets of the MSRV discharge pipe vacuum breakers prior to the previous Unit 2 post-outage drywell closure, as required by procedures. The safety significance was reduced, however, because the affected MSRVs were not rendered inoperable.

O4 Operator Knowledge and Performance

O4.1 Maintaining Shutdown Cooling Requirements

a. Inspection Scope (71707)

The inspector performed checks of the residual heat removal (RHR) shutdown cooling lineup on Unit 2 during plant cooldown for the outage.

b. Observations and Findings

On April 11, 1999, the inspector performed checks of the RHR shutdown cooling lineup during plant cooldown. Shutdown cooling lineup system valves were properly positioned. Required switch positions and caution tags associated with the RHR minimum flow valves were verified to be in accordance with plant procedures. The inspector verified that operators performed surveillances associated with the plant cooldown as required by TS.

During a walkdown of the control room panels, the inspector noted that RHR service water flows through the RHR heat exchangers were not in accordance with Precaution and Limitation 3.45 of Operating Instruction 2-OI-74, Revision 88, Residual Heat Removal System, and Precaution and Limitation 3.13 of Operating Instruction 0-OI-23, Revision 41, Residual Heat Removal Service Water System. The precautions contained instructions to limit temperature on the common discharge piping of the inservice and companion RHR heat exchangers to below the piping design temperature of 150°F. The instructions control common discharge temperature by minimizing RHR service water flow rate through the inservice heat exchanger and establishing a dilution flow rate through the companion heat exchanger.

The inspector observed that the inservice heat exchanger service water outlet temperature exceeded 150°F with a flow rate greater than 1750 gpm and the companion heat exchanger service water flow rate at approximately 2500 gpm. This was contrary to the precautions of Procedures 2-OI-74 and 0-OI-23, which require the inservice heat exchanger flow rate to be less than 1750 gpm and the companion heat exchanger flow rate to be greater than 4000 gpm when the service water discharge temperature of the inservice heat exchanger is greater than 150°F. The inspector informed the operators and the flow rates were immediately corrected.

The inspector reviewed integrated computer system history data of the shutdown cooling system. The data showed that the flow restrictions of the precautions above were not met from the time shutdown cooling was placed in service until the inspector alerted the operators of the condition (approximately 2 hours).

Licensee analysis of system operating data determined that the design temperature of the common discharge was not exceeded and the occurrence did not affect the operability of the RHR service water discharge piping. Failure of the operators to implement Precaution 3.45 of Procedure 2-OI-74 and Precaution 3.13 of Procedure

0-OI-23 is a violation of TS 5.4.1, which requires procedures to be implemented as recommended in Regulatory Guide 1.33, Revision 2, Appendix A, for operation of the RHR service water system. This Severity Level IV violation is being treated as an NCV, consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as PER 99-004430-000, and is identified as NCV 50-260/99-02-02, Failure to Meet RHR Service Water System Discharge Temperature Limitation.

c. Conclusions

An NCV was identified for failure to follow procedures. During shutdown cooling lineup checks for the Unit 2 refueling outage, precautions intended to control temperature on the common service water discharge piping of the residual heat removal heat exchangers were not followed by operators. However, the design temperature of the piping was not exceeded.

O8 Miscellaneous Operations Issues (92901)

O8.1 Closure of Previously Cited Severity Level IV Violations

The NRC recently revised NUREG-1600, Revision 1, "General Statement of Policy and Procedures for NRC Enforcement Actions," (Enforcement Policy) by the addition of Appendix C. Appendix C, Interim Enforcement Policy for Power Reactor Severity Level IV Violations, effective March 11, 1999, revises the NRC's enforcement approach for Severity Level IV Violations. Appendix C permits closure of most Severity Level IV Violations, based on the violations being entered into the licensee's corrective action program, such as initiating a PER, as well as other considerations as described in the appendix. The NRC has conducted a review of the following Severity Level IV Violations, and considers it appropriate to close these violations consistent with Appendix C of the Enforcement Policy:

Violation Number	Corrective Action Program File Number
50-296/98-07-01	PER 98-011475-000
50-259,260,296/98-08-02	PER 98-012990-000
50-260,296/98-09-01	PER 98-014727-000

II. Maintenance

M1 Conduct of Maintenance

M1.1 Surveillance Observations

a. Inspection Scope (61726,71707)

The inspector observed portions of the following surveillance tests:

- Surveillance Instruction 0-SI-4.3.A-16, Reactor Building Isolation Time Delay Relay Calibration

- Surveillance Requirement 0-SR-3.8.1.9 (C OL), Diesel Generator C Emergency Load Acceptance Test with Unit 2 Operating
- Technical Instruction 0-TI-20, Control Rod Drive System Testing and Troubleshooting

b. Observations and Findings

Surveillance tests observed were performed in a professional and safe manner. Personnel performing the tasks were well-prepared and knowledgeable about the equipment and test procedure requirements.

Good coordination and communications was demonstrated during the C diesel generator emergency load acceptance test. The complex test required the coordination of numerous personnel in different plant areas to perform plant manipulations and gather test data. The evolution was completed without problems.

The electricians who performed the reactor building isolation time delay calibration were familiar with the test equipment and were well prepared for the test. Deficiencies revealed by the test were promptly reported to the control room. The WOs which resulted from the deficiencies were expeditiously performed.

c. Conclusions

Surveillance tests observed during the inspection period were performed in a professional and safe manner. Good coordination and communications was demonstrated during the C diesel generator emergency load acceptance test. The complex test required the coordination of numerous personnel in different plant areas to perform plant manipulations and gather test data. The evolution was completed without problems.

M1.2 General Maintenance Comments (62707, 71750)

The inspectors observed portions of the following work activities:

- WO 99-004691-000, Troubleshoot and Repair 3A Recirculation Pump Motor-Generator Set
- WO 97-006387-000 Disassemble/Clean/Refurbish Unit 2 C Outboard Main Steam Isolation Valve
- WO 97-004690, Replace Unit 2 Scram Pilot Diaphragms
- WO 99-002726-001-000, Replace Drywell-to-Torus Vacuum Breaker Test Solenoid Valve 2-FSV-064-0028J

Work activities observed during the inspection period were conducted in a well-planned and professional manner. Workers were familiar with the assigned tasks. Engineering support of the maintenance, where applicable, was good. The engineers frequently

monitored the work and were knowledgeable of the equipment. Proper radiological controls were maintained, when required.

Workers properly halted work and consulted with the maintenance planner when work beyond the original scope of the WO was discovered during the replacement of solenoid valve 2-FSV-064-0028J.

M1.3 Inservice Inspection (ISI) - Observation of Work Activities

a. Inspection Scope, Unit 2, (73753)

The inspector observed the following inservice inspection (ISI) activities:

- Manual ultrasonic examination of 28-inch diameter reactor recirculation weld KR-2-46 and 22-inch diameter reactor recirculation weld KR-2-41.

- Manual ultrasonic examination of reactor pressure vessel head to flange weld RCH-2-2C from the inside vessel head surface.

- Magnetic particle examination of reactor pressure vessel head to flange weld RCH-2-2C from the inside vessel head surface.

- Automated remote ultrasonic examination of the reactor vessel core shroud annulus manway cover at 0 degrees.

- Review of radiographic film for welds RWCU-2-003-026, RCIC-2-009-002, RCIC-2-009-003, PNTSL-2-001-002, and PNTSL-2-001-004.

The above examinations were observed to determine whether the ISI of pressure containing components was performed in accordance with TS, the applicable ASME Code, correspondence between NRC and the licensee concerning relief requests, and requirements imposed by NRC/industry initiatives, including the augmented licensee inspection requirements identified in Generic Letter 88-01, NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping.

b. Observations and Findings

The Code of record for the third 10-year ISI interval for Unit 2 is the 1986 edition of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI, Division 1. During manual ultrasonic inspection of reactor recirculation weld KR-2-41 the inspector noted that the ISI examiners had not brought a marker to define the length and position of indications on the surface of the pipe so that accurate measurements could be taken. This represented poor practice in a very confined high radiation area. After the inspector expressed concern with the way the examiners were measuring the indications, a TVA Level III examiner confirmed the defect lengths and positions.

The licensee decided to perform the manual ultrasonic examination of the reactor pressure vessel head to flange weld RCH-2-2C from the inside vessel head surface because the configuration of the flange prevented the licensee from obtaining full weld coverage from the outside surface. Prior to the ultrasonic examination, the inspector questioned the licensee as to whether the weld would be magnetic particle examined first. The inspector was informed that magnetic particle examination had been performed on the outside of the reactor vessel head as delineated in the ASME Code. The inspector reminded the licensee that the ultrasonic examination was also depicted on the outside of the vessel in the ASME Code and that the apparent purpose of the surface examination, when the weld through-wall would be inspected by ultrasonics, was to cover the area of weld metal under the transducer, which is in the transducers' near field. After further consideration, the licensee decided to magnetic particle examine the head flange weld on the inside surface.

The licensee's automated ultrasonic examination of the manway cover weld @ 0 degrees in the core annulus was performed and evaluated in an effective manner.

During the review of radiographic film and the licensee's radiographic procedure N-RT-1, the inspectors noted that the licensee was using wire penetrameters and the 1992 edition of the ASME Code, Section III, for radiography of Class 1 & 2 welds. Discussions with the licensee revealed that by letter dated March 9, 1995, TVA submitted a request for relief that proposed the use of ASME Code Case N-416-1, "Alternate Pressure Test Requirement for Welded Repairs or Installation of Replacement Items by Welding, Class 1, 2, & 3, Section XI, Division 1." ASME Code Case N-416-1 invokes the 1992 edition, no addenda, of the ASME Code, Section III, in the performance of nondestructive examination on piping weldments. The NRC staff approved the request for relief by letter dated August 18, 1995. ASME Section III, Articles NB-5111 and NC 5111, require that "..Radiographic examination shall be in accordance with Section V, Article 2, except that ...the penetrameters of Table NB-5111-1 and NC-5111-1 shall be used in lieu of those shown in table T-276" (of ASME Section V). Tables NB-5111-1 and NC-5111-1 specify only plaque type penetrameters. However, equivalent wire type penetrameters were incorporated into these tables in the 1993 addenda to the 1992 edition of the ASME Section III Code. TVA determined, with some justification, that the current Code of record allowed the use of wire type penetrameters. In a relief request dated April 27, 1999, TVA requested NRC approval to use wire type penetrameters to expeditiously resolve the issue. On April 29, 1999, Browns Ferry received approval to use wire penetrameters delineated in ASME Section III, 1992 edition with 1993 addenda for inservice inspection radiography.

c. Conclusions

Inservice examination activities observed were performed in a thorough manner by knowledgeable examiners using approved procedures.

M3 Maintenance Procedures and Documentation

M3.1 Hydraulic Snubber Functional Testing and Maintenance

a. Inspection Scope (62707, 61726, 37551)

The inspectors reviewed periodic surveillance functional testing and maintenance of system hydraulic snubbers during the Unit 2 outage. The inspectors observed functional testing of snubbers 2-SNUB-074-5005 and 2-SNUB-001-5058.

b. Observations and Findings

On April 7, 1999, the inspectors reviewed several planned WOs on Unit 2 hydraulic snubbers and noted that two, WO 99-003436-000 for 2-SNUB-071-5008 and WO 99-003437-000 for 2-SNUB-074-5005, were associated with empty fluid reservoirs as indicated by the reservoir plunger indicators. Although the reservoir plunger indicators were not visible, no fluid leakage was observed. These WOs were initiated March 16, 1999, during a periodic visual inspection surveillance.

The inspectors questioned the ability of the two snubbers to properly function with empty reservoirs. The licensee explained that operability was not in question, because no leakage was observed and there were no indications that air had infiltrated the snubber bodies. The licensee stated that the snubbers were in a degraded condition but were still operable because all visual inspection acceptance criteria were met. The inspectors questioned whether Technical Requirements Manual requirements were met and whether a written evaluation was documented to justify continued operation with a degraded snubber. The licensee stated that because all acceptance criteria had been met and no leakage was detected from the snubbers, no evaluation was necessary.

The inspectors observed performance of functional testing for 2-SNUB-074-5005. The snubber passed as-found functional test acceptance criteria. This supported the licensee's operability determination. After refilling the reservoir and performing satisfactory as-left functional testing, the snubber was re-installed in the plant.

The inspectors reviewed the as-found functional test data for 2-SNUB-071-5008. The test data indicated that the acceptance criteria for drag force had been exceeded. The inspectors questioned whether the snubber should be declared inoperable based on the test results. The licensee stated that declaring snubbers operable with as-found drag forces greater than the vendor's recommended 2% of the snubber rated load was allowed with an engineering evaluation. The licensee stated that exceeding the vendor recommended acceptance criteria was acceptable as long as drag force did not exceed 5% of rated load and the attached system pipe stresses were acceptable, based on piping size per a previous civil engineering evaluation. The engineer stated that this evaluation was performed but not documented. The inspectors concluded that the licensee's operability justification was adequate, however, not documenting the engineering evaluation for the high as-found drag forces for the snubber was considered a poor practice.

The licensee initiated PER 99-004157-000 because there was no specified criteria or guidance provided to justify operability or a specified time limit to perform functional testing of snubbers which fail non-acceptance criteria steps. Additionally, the licensee planned to revise test acceptance criteria to more clearly define the acceptability of snubbers which exceed the as-found drag acceptance criteria of 2% of rated load.

On April 29, 1999, the inspectors identified an issue associated with the as-left test data for a third snubber, 2-SNUB-074-5010, located in the residual heat removal system. The data showed that acceptance criteria of Surveillance Instruction 2-SI-4.6.H-2B, Functional Testing of Bergen-Paterson Hydraulic Snubbers (Rev. 8), for tension actuation (lockup) and tension drag force were exceeded. Tension actuation velocity was tested at 18.18 inches/minute and tension drag force was tested at 67.43 pounds versus the maximum acceptance criteria of 18 inches/min (Acceptance Criterion 6.2.2.1) and 60 pounds (Acceptance Criterion 6.2.2.3), respectively. However, the snubber was inappropriately determined to meet test acceptance criteria and was signed off and subsequently re-installed in the plant. The inspectors informed the licensee of this issue.

The licensee initiated PER 99-005236-000 and promptly removed snubber 2-SNUB-074-5010 from the plant for rebuilding. Because the as-left test acceptance criteria were exceeded, the licensee performed an engineering evaluation and determined that the degraded snubber did not have a detrimental effect on the supported system operability.

The failure of licensee personnel to implement procedural steps of Acceptance Criteria 6.2.2.1 and 6.2.2.3 of Surveillance Instruction 2-SI-4.6.H-2B is a violation of TS 5.4.1, which requires procedures to be implemented as recommended in Regulatory Guide 1.33, Revision 2, Appendix A, for surveillance tests. This Severity Level IV violation is being treated as an NCV, consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as PER 99-005236-000, and is identified as NCV 50-260/99-02-03, Failure to Follow Hydraulic Snubber Functional Test Instructions.

c. <u>Conclusions</u>

An NCV was identified for failure to follow procedures. During review of periodic surveillance functional testing and maintenance of system hydraulic snubbers during the Unit 2 outage, as-left acceptance criteria were exceeded for a residual heat removal system snubber. However, the snubber was signed-off as satisfactory, based on an inappropriate, undocumented evaluation.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 <u>(Closed) Inspection Followup Item (IFI) 50-296/96-08-03</u>: Unit 3 Main Steam Isolation Valve (MSIV) Circuitry Failures. This issue was originally identified in NRC Inspection Report 50-259,260,296/96-05, and was subsequently addressed in NRC Inspection Reports 50-259,260,296/96-08, 97-09, and 98-07. Immediate corrective actions to prevent grounding of the affected circuits were to install isolation transformers. After the

licensee identified the root cause to be damaged insulation on conductors in Conax conduit assemblies, the licensee removed the temporarily installed isolation transformers and commenced replacement of Conax conduit assemblies. This IFI was left open to track the licensee's inspection of six remaining Conax conduit assemblies, evaluation of the findings, and implementation of the corrective actions.

The inspector verified that the temporary alteration to install isolation transformers in the MSIV circuitry was closed out, and that the applicable Conax conduit assemblies were replaced on all four limit switches on the Units 2 and 3 inboard MSIVs. The licensee provided objective evidence through documentation. The balance of Conax conduit assemblies was addressed in WOs for each assembly for replacement. Each assembly would be replaced on a priority basis, starting with the outboard MSIVs. There have been no problems with grounds on the installed Conax assemblies that have not been replaced. The inspector concluded that the licensee was taking the appropriate actions to resolve this problem. No further NRC inspection effort will be necessary on this issue.

III. Engineering

E1 Engineering Support of Facilities and Equipment

E1.1 Core Reload Analysis Turbine Trip Modeling Assumptions

a. Inspection Scope (37551)

The inspectors reviewed the licensee's actions when the vendor's core reload analysis was found to inaccurately model plant response to most turbine trip transients.

b. Observations and Findings

NRC Inspection Report 50-259,260,296/99-01, Section E1.1, documented a licensee-identified problem where a safety evaluation was not performed for disabling the main turbine stop valve load limit (SVLL) switches which were described in the Updated Final Safety Analysis Report (UFSAR). NCV 50-260,296/99-01-03, Failure to Perform a Safety Evaluation to Disable Main Turbine SVLL Switches, was identified. The SVLL switches, which sense closure of the main turbine stop valves, provide input to the electro-hydraulic control (EHC) system logic. EHC system response to closure of the stop valves results in the closure of the turbine control valves and opening of the turbine bypass valves. The inspectors considered that the bypass system was operable during the time period that the SVLL switches were disabled, and that an unreviewed safety question did not exist, because actual plant data demonstrated that bypass system response to the steam pressure signal/control valve demand signal mismatch during a turbine trip was faster than the operation of the SVLL switches. Even though the rate of closure of the control valves during a turbine trip is slower than the stop valves, the control valves have an immediate effect on steam pressure during a turbine trip due to being only partially open (about 52%) during full power operation.

During the resolution of this issue, the inspectors reviewed the licensee's core reload analysis, General Electric Standard Application for Reactor Fuel (GESTAR II), NEDE-24011-P-A. The inspectors noted that US Supplement Section S.2.2.1.2, Turbine Trip Without Bypass, description referred to the turbine trip being initiated by the main turbine stop valves. All turbine trips result in closure of both the stop valves and the control valves with one exception; the generator load reject turbine trip results in closure of only the main turbine control valves. The inspectors questioned how the turbine trip transient was modeled in the core reload analysis, because actual plant pressure would respond more quickly to main turbine control valve closure vice the stop valves for most turbine trips.

After consulting with the vendor, the licensee determined that GESTAR II performs the analysis assuming that only the stop valves close for all turbine trips with the exception of generator load reject. The licensee initiated PER 99-003659-000 because GESTAR II incorrectly modeled actual plant response during the turbine trips. The incorrect modeling assumptions had the potential to affect OLMCPR results. The most limiting transient was determined to be the feed water controller failure transient with the turbine bypass valves out of service which results in a turbine trip on high reactor vessel level.

The licensee's vendor, General Electric, performed the feed water controller failure transient analysis based on closure of the turbine control valve closure. The calculated difference for the Units 2 and 3 current operating cycles OLMCPR was determined to be +0.003. However, this small non-conservative difference in calculated OLMCPR did not impact the OLMCPR reported in the COLR. This was because OLMCPR is reported to the nearest one-hundredth of a unit. Therefore, the error was considered to be within the accuracy of the analysis.

The inspectors concluded that no violation of regulatory requirements occurred and no further follow up of licensee actions was warranted because the COLR OLMCPR was not effected. However, the non-conservative turbine trip modeling assumptions of GESTAR II potentially affect all boiling water reactors which use General Electric to perform the core reload analysis. Because the consequences of the incorrect modeling assumptions are plant and core specific, there is a potential for the COLR OLMCPR for these plants to be affected. On March 23, 1999, General Electric initiated Potential Safety Concern (PSC-9906) in accordance with their quality assurance program to address this concern and evaluate reportability in accordance with 10 CFR Part 21.

c. <u>Conclusions</u>

The modeling assumptions for most turbine trip transients in the licensee's core reload analysis, General Electric Standard Application for Reactor Fuel (GESTAR II), NEDE-24011-P-A, incorrectly assumed that the associated transient pressure response was controlled by the turbine stop valves vice the turbine control valves. However, the reported OLMCPR was not effected for the current operating cycles of Units 2 and 3.

E1.2 Failure to Perform 10 CFR 50.59 Safety Evaluation for HPCI Testing

a. Inspection Scope (37551)

The inspectors reviewed actions taken by the licensee to address a concern that a safety evaluation was not performed for a post-modification testing configuration of the HPCI system. This configuration resulted in the defeat of the automatic function of an UFSAR valve.

b. Observations and Findings

On February 16, 1999, one of two Unit 2 HPCI test return shutoff valves (in series) was de-energized in a partially open position which defeated the automatic function of the valve to close by the signal which actuates system operation. The function of the valve to close by the signal which actuates system operation is described in the UFSAR, Section 6.4.1. The valve was in this condition for implementation of testing associated with a modification prior to the Unit 2 outage. Based on discussion with the licensee, the inspectors determined that a 10 CFR 50.59 safety evaluation had not been performed prior to de-energizing the shutoff valve.

Further licensee investigation determined that at the time that the WO was planned, the planner expected the WO to be worked during a future outage. When the decision was made to work the WO without entering a TS Limiting Condition for Operation (LCO), the steps of procedure MMDP-1, Maintenance Management System, which would have identified the need for a 10 CFR 50.59 review, had already been performed. The licensee did not recognize that the assumption made by the planner had been invalidated with the decision to do the test with the system operable. The licensee determined that Procedure SPP-9.4, 10 CFR 50.59 Evaluations of Changes, Tests, and Experiments, would have required a screening review, safety assessment, and safety evaluation for this WO to be performed while the HPCI system was considered operable. The licensee documented the issue in PER 99-002311-000.

With the HPCI test return valve de-energized in a partially open position, the normal boundary of the system was expanded to the second normally closed test return shutoff valve. The system is classified as ASME Code Class 2 equivalent up to the first HPCI test return shutoff valve. Downstream of this valve, to the second shutoff valve, the piping is designated as non-nuclear code class. However, this piping is designed to the same pressure and temperature, as noted on the system flow diagram. The licensee determined that the conclusions from a previous safety evaluation which was written for this system configuration on Unit 3 were applicable to Unit 2, and that the work on the HPCI test return valve did not involve an unreviewed safety question. The inspectors reviewed the Unit 3 safety evaluation, and did not identify any problems with the licensee's conclusions.

10 CFR 50.59 requires, in part, that the licensee shall maintain records of changes in the facility to the extent that these changes constitute changes in the facility as described in the safety analysis report and that these records must include a written safety

evaluation which provides the basis that the change does not involve an unreviewed safety question. The UFSAR stated that a full-flow test line is provided to verify system operation. The line directs flow to the condensate storage tank when the shutoff valves are open. These valves are sequenced to close by the signal which actuates system operation and are interlocked closed when either suction valve from the suppression pool is open. On February 16, 1999, while the system was considered operable, one of the Unit 2 HPCI test return shutoff valves was de-energized in a partially open position which defeated the automatic function of the valve to close by the signal which actuates system operation. This Severity Level IV violation is being treated as an NCV, consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as PER 99-002311-000 and is identified as NCV 50-260/99-02-04, Failure to Perform a Safety Evaluation for HPCI Testing (EA 99-127).

c. Conclusions

An NCV was identified in connection with the licensee's failure to perform a safety evaluation in support of work/testing on the HPCI system with the system being operable, as required by plant procedures and 10 CFR 50.59.

E8 Miscellaneous Engineering Issues (92903, 71707)

E8.1 (Closed) IFI 50-259,260,296/97-01-01: Resolution of UFSAR Discrepancies. Since February 1996, as documented in NRC Inspection Report 50-259,260,296/96-03, the inspectors have identified several discrepancies in the UFSAR text. In addition, the licensee identified many other discrepancies and areas requiring clarification as a result of an extensive voluntary effort to review and correct the UFSAR as appropriate. A listing consisted of 1120 discrepancies were identified under PER 96-00204-000 and as a result of team reviews of 106 UFSAR sections under PER 97-00226-000, 60 additional issues were identified because of conflicts between the wording in the UFSAR and the TS, plant instructions, or plant configuration. The inspector determined that the licensee was approximately 95% complete in resolving the list of issues, i.e., a change to the UFSAR has been completed, submitted or a justification provided. All open actions were scheduled for completion by August 1, 1999.

The inspectors noted that the licensee had implemented a thorough and comprehensive review process in order to correct the UFSAR. This was facilitated by providing direction through Technical Instruction 0-TI-353, Updated FSAR Functional Review Criteria.

The inspectors concluded that the licensee was near enough to completion of their effort to validate and update the contents of the UFSAR, such that no further tracking of the licensee's progress was necessary.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Occupational Radiation Exposure Control Program

a. Inspection Scope (83750)

The inspector reviewed implementation of selected elements of the licensee's radiation protection program during the U2C10 RFO. The review entailed observation of radiological protection activities including personnel exposure monitoring, radiological postings, verification of posted radiation dose rates and contamination levels within the radiologically controlled area (RCA). Those activities were evaluated for consistency with the programmatic requirements, personnel monitoring requirements, occupational dose limits, radiological posting requirements, and survey requirements specified in Subparts B, C, F, G, and J of 10 CFR 20.

b. Observations and Findings

The inspector conducted frequent tours of the RCA to observe radiation protection activities and practices. Personnel preparing for routine entries into the RCA and for entries into the drywell were observed being briefed on the radiological conditions in the areas to be entered. The briefings were given by radiation control personnel before access was granted and covered the dosimetry and the protective clothing and equipment required by the radiation work permit (RWP). The administrative limits for the allowed dose and dose rate were emphasized during the briefings. The briefings provided thorough descriptions of the existing dose rates which could be encountered. The inspector determined that personnel entering the RCA were adequately briefed on the radiological hazards which could be encountered while in the RCA and the radiological protective measures required to be taken. Individuals at selected job sites were interviewed and the inspector determined that the workers were aware of their administrative dose and dose rate limits, the work area dose rates, the proximate low-dose waiting areas, areas of high contamination, and protective clothing required by the RWP.

The inspector observed the use of personal radiation exposure monitoring devices by personnel entering and exiting the RCA. Thermoluminescent dosimeters (TLDs) were used as the primary device for monitoring personnel radiation exposure. In addition, digital alarming electronic dosimeters (EDs) were used for monitoring the accumulated dose and the encountered dose rates during each RCA entry. The EDs were set to alarm at administrative limits established for the specific RWP under which the RCA entry was being made. As the individuals exited the RCA, the accumulated dose and encountered dose rate information was transferred from the EDs to the radiation exposure system (REXS) data base in order to track individual exposures. During tours of the RCA, the inspector noted that the required dosimetry was being properly worn by personnel when entering and while in the RCA. The inspector also noted that personnel

exiting the RCA routinely surveyed themselves for contamination using personal contamination monitors.

During tours of the RCA, the inspector noted that general areas and individual rooms were properly posted for radiological conditions. Survey maps indicating dose rates and contamination levels at specific locations within the RCA were posted at the entrance to the RCA. Radiological postings were also conspicuously displayed at individual contaminated and high radiation areas. At the inspector's request, a licensee health physics technician performed dose rate and contamination surveys in several rooms and locations. The inspector verified that the survey instrument readings were consistent with the posted area dose rates. Contact dose rates from several radioactive material-bearing containers were also verified to be consistent with the dose rates recorded on container labels. Independent contamination surveys performed around several posted contaminated areas indicated that contamination was not being tracked out of the contaminated areas.

The inspector compiled the annual and outage collective dose data presented in the table below from the licensee's REXS and as low as reasonably achievable (ALARA) reports. The REXS tracks the cumulative dose on a fiscal year, rather than a calendar year, basis and therefore the annual ALARA goals were also established on a fiscal year basis. The outage doses were listed in the table by the calendar year in which they occurred and in some cases the outage periods crossed fiscal year ends.

Collective Dose (Man-Rem)									
Annual Dose						Outage Dose			
Fiscal Year[7]	Actual	Goal	Calendar Year	Actual	3 Year Mean	Unit/ Cycle	Actual	Goal	Days
1994	426[1]	500	1994	855[1]	747	U2C7[4]	424[1]	480	54
1995	850[1]	895	1995	409[1]	711				
1996	432[1]	510	1996	384[1]	549	U2C8[4]	241[1]	350	32
1997	283[1]	360	1997	516[1]	436	U3C7[4]	56[1]	180	19
						U2C9[4]	277[1]	342	21
1998	517[1]	489	1998	360[1]	420	U3C8[4]	171[1]	170	25
1999	385[2,3]	520[1]	1999	264[2,3]		U2C10[4]	193[2,3]	345[5]	27[6]

[1] TLD data
[2] ED data
[3] As of 4/22/99
[4] RFO
[5] U2C10 Outage Goal established at 345 man-rem as measured by ED based on a

Goal of 283 man-rem as measured by TLD
[6] Scheduled for 27 days beginning 4/11/99
[7] October 1 of previous year to September 30 of stated year

As indicated in the table, the licensee was usually successful at meeting established ALARA goals, in that eight of ten goals were met during 1994 through 1998. Twelve days into the scheduled 27 day U2C10 RFO, the licensee was on track for meeting the outage goal.

The licensee also provided the inspector with data from the REXS data base pertaining to maximum individual radiation exposures for 1998 and year-to-date 1999. The inspector verified that the data were consistent with the REXS data base and tabulated the data in the table below.

Maximum Individual Radiation Doses (Rem)				
Calender Year	TEDE	Skin	Extremity	Eye Lens
1998	2.815[1]	3.411[1]	2.869[1]	2.850[1]
1999	1.867[2]	NA[3]	NA[3]	NA[3]
Regulatory and Administrative Limits				
10 CFR 20	5.000	50.000	50.000	15.000
Admin.	1.000	10.000	10.000	3.000

[1] Official doses of record
[2] ED data as of 4/19/99
[3] Not monitored by ED

The administrative annual dose limits established by the licensee were delineated in Section 3.4.1.6 and Table 1 of Procedure SPP-5.1, Radiological Controls, Revision 2. The procedure specified that the administrative limits could be exceeded only if authorized by the site radiological and chemistry control manager, and that exposures exceeding regulatory limits required authorization by the site radiological and chemistry control manager, the plant manager and the site vice president. As indicated in the table, the maximum individual radiation exposures were well within the regulatory limits for occupational dose specified in 10 CFR 20.1201(a).

The inspector reviewed the licensee's procedures for follow-up actions to personnel contamination events (PCEs) and reviewed selected records for those events which occurred during 1998. Field Operations Implementing Procedure No. 1, Personnel Decontamination, Revision 75, of Radiological Control Instruction (RCI)-1.1 indicated that the threshold for initiating follow-up actions was skin or personal clothing contamination in excess of 100 net counts per minute (ncpm) as measured by a hand held frisker. (Contamination on licensee provided modesty garments and contamination from noble

gas were not counted as PCEs.) The licensee's records indicated that 56 PCEs had occurred as of April 22. Twelve occurred prior to the start of the U2C10 outage and 44 during the first eleven days of the outage. Dosimetry Implementing Procedure (DOS-IP) No. 7, Skin Dose Assessment and Calculation, Revision 42, of RCI-2.1 specified that dose assessments were to be initiated whenever an individual may have received a shallow dose to the skin of the whole body or to the extremities in excess of 100 millirem (mrem) from skin or personal clothing contamination. No PCEs resulted in skin doses exceeding that procedurally established threshold. Procedure SPP-5.1 required the performance of bioassay for any indication of an intake of radioactive material. Procedure DOS IP-7, Internal Dose Calculations, Revision 26, of RCI-8.1 specified that any bioassay results greater than the minimum detectable activity required calculation of the internal dose. Procedure SPP-5.1 required follow up investigation and additional internal dose assessments whenever bioassay results indicated that an individual may have had an intake of radioactive material in excess of one percent of the annual limit on intake. The licensee's records indicated that internal dose assessments were initiated for one intake which occurred prior to the U2C10 outage and for nine intakes which occurred during the first twelve days of the outage. Preliminary results indicated that the internal doses were less than 25 mrem. No regulatory dose limits were exceeded.

The inspector also reviewed the licensee's records for contaminated floor space within the RCA. Radiological control personnel maintained records of the areas within the RCA, excluding the drywells, which had contamination levels in excess of 1000 disintegrations per minute per 100 square centimeters (dpm/100 cm^2). Contaminated areas (C-zones) were categorized as either temporarily C-zones or non-recoverable/exempt areas. The C-zone square footage was tracked on a daily basis and weekly averages were calculated. The inspector noted that during non-outage periods the weekly averages for C-zone square footage during 1999 (year-to-date) were less than one half of one percent of the RCA floor space and the non-recoverable/exempt areas were 15 percent of the RCA.

c. <u>Conclusions</u>

The licensee was properly monitoring and controlling personnel radiation exposure during the U2C10 RFO and posting area radiological conditions in accordance with 10 CFR Part 20. Personnel entering the RCA were adequately briefed on radiological hazards and protective measures. Maximum individual radiation exposures were controlled to levels which were well within the regulatory limits for occupational dose specified in 10 CFR 20.1201(a). The licensee was generally successful in meeting established ALARA goals, in that eight of ten goals were met during 1994 through 1998.

V. Management Meetings

X1 Exit Meeting Summary

The resident inspectors presented inspection findings and results to licensee management on May 7, 1999. Additional formal meetings to discuss inspection findings were conducted on April 23, 1999. The licensee acknowledged the findings presented. The licensee did not identify any of the materials reviewed during this inspection as proprietary.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

T. Abney, Licensing Manager
J. Brazell, Site Security Manager
T. Burzese, Supervisor, Radiation Protection
R. Coleman, Radiological Control Manager
J. Corey, Radiation Protection and Chemistry Manager
R. Greenman, Site Support Manager
J. Johnson, Site Quality Assurance Manager
R. Jones, Plant Manager
J. Ledgerwood, Maintenance Superintendent
G. Little, Operations Manager
R. Moll, System Engineering Manager
W. Nurnberger, Chemistry Superintendent
D. Olive, Operations Superintendent
R. Ryan, Site Engineering Manager
D. Sanchez, Training Manager
J. Schlessel, Maintenance Manager
J. Shaw, Design Engineering Manager
B. Shriver, Assistant Plant Manager
K. Singer, Site Vice President

INSPECTION PROCEDURES USED

IP 37551	Engineering
IP 61726	Surveillance Observations
IP 62707	Maintenance Observations
IP 71707	Plant Operations
IP 71750	Plant Support Activities
IP 73753	Inservice Inspection
IP 83750	Occupational Radiation Exposure
IP 92901	Follow-up-Plant Operations
IP 92902	Follow-up-Maintenance
IP 92903	Follow-up-Engineering

ITEMS OPENED AND CLOSED

Opened and Closed

50-260/99-02-01	NCV	Failure to Remove MSRV Vacuum Breaker Covers (Section O2.1).
50-260/99-02-02	NCV	Failure to Meet RHR Service Water System Discharge Temperature Limitation (Section O4.1).

50-260/99-02-03	NCV	Failure to Follow Hydraulic Snubber Functional Test Instructions (Section M3.1).
50-260/99-02-04	NCV	Failure to Perform a Safety Evaluation for HPCI Testing (EA 99-127)(Section E1.2).

Closed

50-296/98-07-01	VIO	Failure to Comply with LCO 3.0.4 for HPCI System Operability (Section O8.1).
50-259,260,296/98-08-02	VIO	Inadequate SBGT Heater Flow Switch Logic Functional Test (Section O8.1).
50-260,296/98-09-01	VIO	Inadequate Instrument Checks and Observations Procedure (Section O8.1).
50-296/96-08-03	IFI	Unit 3 Main Steam Isolation Valve Circuitry Failures (Section M8.1).
50-259,260,296/97-01-01	IFI	Resolution of UFSAR Discrepancies (Section E8.1).