UNITED STATES
**NUCLEAR REGULATORY COMMISSION**
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
61 FORSYTH STREET SW SUITE 23T85
ATLANTA, GEORGIA 30303-8931

July 26, 2000

EA 98-543

Duke Energy Corporation
ATTN: Mr. W. R. McCollum
Site Vice President
Oconee Nuclear Station
7800 Rochester Highway
Seneca, SC 29672

SUBJECT: OCONEE NUCLEAR STATION - NRC INSPECTION REPORT 50-269/00-05, 50-270/00-05, AND 50-287/00-05

Dear Mr. McCollum:

On July 1, 2000, the NRC completed inspections at your Oconee facility. The enclosed report presents the results of the inspections. The results of the inspections were discussed on July 5, 2000, with Mr. J. Forbes and other members of your staff.

The inspections were an examination of activities conducted under your licenses as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your licenses. Within these areas, the inspections consisted of a selective examination of procedures and representative records, observations of activities, and interviews with personnel.

The NRC identified nine issues that were evaluated under the risk significance determination process and were determined to be of very low safety significance (Green). These issues have been entered into your corrective action program and are discussed in the summary of findings and in the body of the attached inspection report. Of the nine issues, all were determined to involve violations of NRC requirements, but because of their very low safety significance the violations are not cited. In addition, a non-cited violation involving failures to make required reports to the NRC, is also identified in the attached report. This non-cited violation was not evaluated using the significance determination process. If you contest these non-cited violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the United States Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001, with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Oconee facility.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/NRC/ADMAS/index.html (the Public Electronic Reading Room).

Sincerely,

***/RA/***

Charles R. Ogle, Chief
Reactor Projects Branch 1
Division of Reactor Projects

Docket No: 50-269, 50-270, 50-287
License No: DPR-38, DPR-47, DPR-55

Enclosure: Inspection Report w/Attachments: (1) NRC's Revised Reactor Oversight Process and (2) Oconee Nuclear Site Exercise Narrative

cc w/encl:
Compliance Manager (ONS)
Duke Energy Corporation
Electronic Mail Distribution

Lisa Vaughn
Legal Department (PB05E)
Duke Energy Corporation
422 South Church Street
Charlotte, NC 28242

Rick N. Edwards
Framatome Technologies
Electronic Mail Distribution

Anne Cottingham
Winston and Strawn
Electronic Mail Distribution

Mel Fry, Director
Division of Radiation Protection
N. C. Department of Environmental
Health & Natural Resources
Electronic Mail Distribution

Virgil R. Autry, Director
Div. of Radioactive Waste Mgmt.
S. C. Department of Health and
Environmental Control
Electronic Mail Distribution

R. Mike Gandy
Division of Radioactive Waste Mgmt.
S. C. Department of Health and
Environmental Control
Electronic Mail Distribution

County Supervisor of
Oconee County
415 S. Pine Street
Walhalla, SC 29691-2145

Lyle Graber, LIS
NUS Corporation
Electronic Mail Distribution

L. A. Keller, Manager
Nuclear Regulatory Licensing
Duke Energy Corporation
526 S. Church Street
Charlotte, NC 28201-0006

Peggy Force
Assistant Attorney General

DEC 3

N. C. Department of Justice
Electronic Mail Distribution

<u>Distribution w/encl</u>:
D. LaBarge, NRR
PUBLIC

| OFFICE | RII:DRP | RII:DRP | RII:DRP | RII:DRP | RII:DRP | RII:DRS | RII:DRS |
|---|---|---|---|---|---|---|---|
| SIGNATURE | CRO for | MS | DB | EC | SF | ET per email | WS |
| NAME | RCarroll alt | MShannon | DBillings | EChristnot | SFreeeman | ETesta | WSartor |
| DATE | 07/26/2000 | 07/18/2000 | 07/18/2000 | 07/18/2000 | 07/18/2000 | 07/26/2000 | 07/20/2000 |
| E-MAIL COPY? | YES NO | YES NO | YES NO | YES NO | YES NO | YES NO | YES NO |
| OFFICE | RII:DRS | RII:DRS | RII:DRS | RII:EICS | | | |
| SIGNATURE | JK | RS | GW | AB | | | |
| NAME | JKreh | RSchin | GWiseman | ABoland | | | |
| DATE | 07/20/2000 | 07/20/2000 | 07/21/2000 | 07/20/2000 | 8/ /2000 | 8/ /2000 | 8/ /2000 |
| E-MAIL COPY? | YES NO | YES NO | YES NO | YES NO | YES NO | YES NO | YES NO |

OFFICIAL RECORD COPY DOCUMENT NAME: C:\0005drp.wpd

U. S. NUCLEAR REGULATORY COMMISSION

REGION II

| | |
|---|---|
| Docket No: | 50-269, 50-270, 50-287 |
| License No: | DPR-38, DPR-47, DPR-55 |
| Report No: | 50-269/00-05, 50-270/00-05, 50-287/00-05 |
| Licensee: | Duke Energy Corporation |
| Facility: | Oconee Nuclear Station, Units 1, 2, and 3 |
| Location: | 7800 Rochester Highway<br>Seneca, SC 29672 |
| Dates: | April 2, 2000 - July 1, 2000 |
| Inspectors: | M. Shannon, Senior Resident Inspector<br>D. Billings, Resident Inspector<br>E. Chrisnot, Resident Inspector<br>S. Freeman, Resident Inspector<br>E. Testa, Senior Radiation Specialist (Sections 2OS1, 2OS2, 2OS4)<br>W. Sartor, Senior Emergency Preparedness Inspector (Sections 1EP1, 4OA2)<br>J. Kreh, Emergency Preparedness Inspector (Sections 1EP1, 4OA2)<br>R. Schin, Senior Reactor Inspector (Sections 1R05, 4OA6.2)<br>G. Wiseman, Senior Reactor Inspector (Section 1R05) |
| Approved by: | C. Ogle, Chief<br>Reactor Projects Branch 1<br>Division of Reactor Projects |

SUMMARY OF FINDINGS

Oconee Nuclear Station, Units 1, 2, and 3
NRC Inspection Report 50-269/00-05, 50-270/00-05, and 50-287/00-05

The report covers a 12-week period of resident inspection and announced inspections by regional health physics inspector, emergency preparedness inspectors, and fire protection inspectors. The significance of issues is indicated by their color (green, white, yellow, red) and was determined by the Significance Determination Process (Inspection Manual Chapter 0609), as discussed in the attached summary of the NRC's Revised Reactor Oversight Process.

**Cornerstone: Initiating Events**

- Green. A non-cited violation of Technical Specification 5.4.1 was identified for a failure to follow administrative procedural controls to verify that a working copy of an operating procedure was the latest revision. On May 14, 2000, this resulted in an approximate 150 percent over-pressurization of the Unit 3 low pressure injection and building spray suction piping. This issue was determined to have very low safety significance due to the actual pressure not exceeding the allowable piping pressure (Section 1R14.3).

**Cornerstone: Mitigating Systems**

- Green. A non-cited violation of 10 CFR 50, Appendix R, was identified for reactor coolant pump 1B1 and 2A1 oil collection systems not being capable of collecting lube oil from all leakage locations in August 1998 and June 1999, respectively. This issue was determined to have very low safety significance, because adequate fire detection equipment was installed in the associated reactor buildings and the arrangement of safety-related equipment was such that the likelihood of a reactor coolant pump oil fire affecting any safety systems was minimal (Section 1R05.3).

- No Color. A non-cited violation of 10 CFR 50.72 and 50.73 was identified for failure to report to the NRC conditions outside of the design basis, involving instances of reactor coolant pump 1B1 and 2A1 oil collection system leaks in August 1998 and June 1999, respectively (Section 1R05.3).

- Green. The inspectors identified a non-cited violation of Technical Specification 5.4.1 concerning a failure to follow work control procedures on June 26, 2000, for delaying planned maintenance on Unit 3 Standby Breaker $S_{1\text{-}3}$ and performing preventive maintenance out of sequence. This resulted in an increased likelihood of an initiating event while one of the emergency power supplies was degraded. This issue was determined to have very low safety significance due to the low probability of actually causing an initiating event and that the emergency power supplies were not completely lost (Section 1R13).

- Green. The inspectors identified a non-cited violation of Technical Specification 5.4.1 for an inadequate operating procedure that was used during Unit 2 power escalation on April 19, 2000. Specifically, because the operating procedure did not prohibit it, operators continued to increase Unit 2 reactor power after nuclear instrumentation became greater than 2 percent non-conservative. This resulted in reactor protection system trips for nuclear overpower, reactor coolant pump to power, and nuclear overpower flux/flow imbalance becoming inoperable. This issue was determined to have very low safety significance in that other reactor trip functions were available to protect the reactor core (Section 1R14.2).

- Green. The inspectors identified a non-cited violation of Technical Specification 5.4.1 for failure to properly implement procedures to calibrate the controls to Unit 1 equipment room chilled water valve 1WC-191 following replacement of the valve on March 8, 2000. This resulted in a failure to supply cooling water to one air handling unit for the Unit 1 equipment room. This issue was determined to have very low safety significance because the other train of equipment room cooling was available during the period that chill water valve 1WC-191 was inoperable (Section 1R19).

- Green. The inspectors identified a non-cited violation of Technical Specification 3.5.3 for failure to maintain one Unit 3 train of low pressure injection operable in the emergency core cooling system mode during Mode 4 on April 13, 2000. This issue was determined to have very low safety significance because the operators had control of the danger tags and could have energized the valve operator breakers if required. In addition, it was determined to have very low safety significance because of the reduced reactor coolant temperatures and the short duration that the valves were inoperable (Section 1R20).

- Green. The inspectors identified a non-cited violation of Technical Specification 5.5.9 for failure to refurbish or to replace seven Unit 3 relief valves that had failed to meet their respective relief valve testing acceptance criteria in April 2000. This issue was determined to have very low safety significance because the relief valves would still function to relieve pressure, although slightly outside the prescribed limits, and therefore, were considered to be functional although degraded (Section 1R22.2).

- Green. The inspectors identified a non-cited violation of Technical Specification 5.5.9 for establishing improper test acceptance criteria which did not meet the American Society of Mechanical Engineers code design requirements for ensuring that relief valves would achieve rated lift capability at less than 10 percent above system design. This issue, identified in April 2000, was determined to have very low safety significance because the relief valves would still function to relieve pressure, although slightly outside the prescribed limits, and therefore, were considered to be functional although degraded (Section 1R22.2).

- Significance to be Determined. On April 22, 2000, during the Unit 3 refueling outage, the licensee partially flooded the low pressure injection pump room. This issue was considered to have potential risk significance in that the other low pressure injection pumps were inoperable due to maintenance and modification work. In addition, a potential violation of 10 CFR 50 Appendix B, Criterion XVI was identified for the flooding of the Unit 3 low pressure injection room, because corrective actions for previous LPI room flooding incidents had not been adequately implemented. Pending further review, the flooding issue with the related potential violation, was considered to be an unresolved item (Section 1R23).

**Cornerstone: Barrier Integrity**

- Green. The inspectors identified a non-cited violation of 10 CFR 50, Appendix B, Criterion III, for failure to evaluate the compatibility and suitability of materials, used to help seal the containment purge valves, prior to installation and use of the materials on the containment purge valves. This issue was determined to have very low safety significance in that the valves were tested prior to operation and again prior to the start of the refueling outage and no increase in leakage or degradation was identified (Section 1R17.2).

## Report Details

Summary of Plant Status:

Unit 1 was at 100 percent power throughout the inspection period except for a brief period on May 20, 2000, when reactor power was reduced to 87 percent to facilitate control rod and main turbine valve testing.

Unit 2 was at 100 percent power throughout the inspection period except for two power reductions. The unit was reduced to 20 percent power on April 19, 2000, to repair a leaking valve on the reactor coolant system and returned to 100 percent power on April 22, 2000. On June 17, 2000, the unit was reduced to 25 percent power to repair a steam leak on a piping flange to the 2D2 flash tank. Following repairs, the unit was returned to 100 percent power on June 18, 2000.

Unit 3 began the period at 100 percent power. On April 13, 2000, the unit was shutdown for the End-of-Cycle 18 refueling outage. After refueling, the unit was taken critical on May 18, 2000, and returned to 100 percent power on May 23, 2000. The unit was reduced to 10 percent power on May 24, 2000, due to main exciter bearing vibration problems. Following repairs, the unit returned to 100 percent power on May 30, 2000. On June 22, 2000, the unit was reduced to 70 percent power when a condenser waterbox outlet valve failed closed. Following repairs, the unit returned to 100 percent power on June 23, 2000, and operated there for the remainder of the inspection period.

### 1. REACTOR SAFETY
**Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity**

1R04 Equipment Alignment

a. Inspection Scope

The inspectors conducted equipment alignment partial walkdowns to evaluate the operability of selected redundant trains or backup systems, listed below, with the other train or system inoperable or out of service. The walkdowns included, as appropriate, consideration of plant procedures and reviews of documents to determine correct system lineups, and verification of critical components to identify any discrepancies which could affect operability of the redundant train or backup system. The following systems were included in this review:

- Emergency alternating current power system during the removal from service of the Keowee Hydro Units (KHU),
- Decay heat removal system and the core temperature monitoring, during reactor coolant system (RCS) reduced inventory activities, and
- Unit 1B high pressure injection system train during preventive maintenance and replacement of the power supply breaker to the 1A high pressure injection (HPI) pump.

b. Issues and Findings

No findings were identified.

1R05 Fire Protection

.1 Monthly Fire Protection Inspection

a. Inspection Scope

The inspectors conducted tours of areas important to reactor safety to verify that combustibles and ignition sources were properly controlled, and that fire detection and suppression capabilities were intact. The inspectors selected the areas based on a review of the licensee's safe shutdown analysis and the probabilistic risk assessment based sensitivity studies for fire-related core damage accident sequences. Inspection of the following areas were conducted during this inspection period; Unit 1 and Unit 2 purge inlet room, Unit 1 east and west penetration rooms, cask decontamination room, CT4 transformer blockhouse, and the Unit 1, Unit 2 and Unit 3 cable spreading rooms.

b. Issues and Findings

No findings were identified.

.2 Fire Brigade Drill Performance

a. Inspection Scope

The inspectors observed fire brigade drills on April 5 and April 7, 2000. The inspectors observed the drill to verify that: protective clothing and turnout gear was properly donned; breathing apparatus was properly worn and used; hoses were capable of reaching the location, laid out without constrictions, equipped with the proper nozzle, and charged or simulated charged; the fire area was entered in a controlled manner; sufficient equipment was brought to the scene to fight the fire; the team leader's directions were thorough and effective; radio communications were effective; effective smoke removal operations were utilized; the pre-plans were used; and the drill scenario was followed and the objectives met.

b. Issues and Findings

No findings were identified.

.3 (Closed) Unresolved Item (URI) 50-269,270/99-06-05: Review of Drip Pan Leakage in the Reactor Coolant Pump (RCP) Oil Collection Systems

This URI involved two instances where RCP lube oil leaks were not collected by the RCP oil collection systems. These instances involved RCP 1B1 in August 1998 and RCP 2A1 in June 1999. The licensee determined that about 7.8 gallons of RCP lube oil leaked out beyond the oil collection systems in August 1998 and about 10 gallons in June 1999. Also, operators saw smoke in the Unit 2 reactor building in June 1999 due to RCP lube oil vaporizing from contact with hot RCS piping. The identified causes were that the RCP oil collection drip pans were defective, they leaked due to a crack in a formed corner and a poor joint seal assembly, and maintenance procedural guidance was inadequate. The licensee entered these events into the corrective action program [Problem Investigation Process (PIP) Report 1-O98-03838 for RCP 1B1 and PIPs 2-O99-02532 and 2-O99-02646 for RCP 2A1]. However, the licensee had not reported these events to the NRC.

10 CFR 50, Appendix R, Paragraph III.0, requires that the oil collection system for RCPs shall be capable of collecting lube oil from all potential pressurized and unpressurized leakage sites and draining it to a vented closed container that can hold the entire lube oil system inventory. Updated Final Safety Analysis Report (UFSAR) Section 9.5.1.6.1 and the licensee's Fire Protection Program (OSS-0254.00-00-4008, Appendix D, Response to 10 CFR 50 Appendix R) state that the RCPs are provided with seismically qualified oil collection systems to prevent oil spillage from reaching areas which may be above the flash point of the lubrication oil. It also states that the lower oil pots have been modified with a shield (drip pan) to catch oil and carry it through a properly sized drain line into a collection tank.

10 CFR 50.72 and 50.73 require licensees to notify the NRC of identified plant conditions that are outside the design basis of the plant.

After further in-office review, the inspectors concluded that, contrary to the above requirements, the RCP 1B1 and RCP 2A1 oil collection systems were not capable of collecting lube oil from all leakage sites in August 1998 and in June 1999, respectively. This was demonstrated by the fact that substantial quantities of lube oil (7.8 to 10 gallons) actually leaked out of the oil collection systems. The inspectors further concluded that these instances where the RCP oil collection systems were not capable of collecting oil from all leakage sites represented plant conditions that were outside the design basis of the plant and therefore must be reported to the NRC.

The licensee's corrective actions included repairing the RCP oil collection systems, using a better grade of sealant on the gasket, and enhancing the maintenance procedural guidance. Also, the licensee subsequently reported the June 1999 event to the NRC in LER 50-270/99-04 and Supplement 1 to that LER. In that LER, the licensee stated that they had refurbished the Unit 2 RCP oil collection system and planned to inspect and refurbish as necessary the Units 1 and 3 RCP oil collection systems during the next refueling outages. In addition, the licensee stated plans to add the RCP oil collection system enclosures to the preventive maintenance program for each unit.

This issue was identified during an NRC inspection that occurred prior to the April 2, 2000, implementation of the Reactor Oversight Program. Consequently, not all information needed to fully implement the new Significance Determination Process was obtained. However, the inspectors and a senior reactor analyst considered that there was adequate fire detection equipment installed in the reactor building. Also, the arrangement of safety-related equipment was such that the likelihood of a RCP oil fire affecting any safety systems was minimal. Consequently, they concluded that the conditions related to this issue represented a very low safety significance (green).

This violation of 10 CFR 50, Appendix R, is being treated as a Non-Cited Violation, consistent with Section VI.A of the NRC Enforcement Policy. It is identified as NCV 50-

269,270/00-05-01: Failures of RCP Oil Collection System to Collect Oil. Additionally, the violation of 10 CFR 50.72 and 10 CFR 50.73 for failing to initially report this problem is also being treated as an NCV, consistent with Appendix VI.A of the NRC Enforcement Policy. It is identified as NCV 50-269,270/00-05-02: Failure to Report Conditions Outside of Appendix R Design Basis. URI 50-269,270/99-06-05 is closed.

1R11 Licensed Operator Requalification

a. Inspection Scope

The inspectors observed control room simulator training scenarios on April 12, 2000, to assess licensed reactor operator and senior reactor operator performance. The training scenarios involved a loss of all AC power and a reactor trip with a subsequent loss of coolant accident. The inspectors focused on the performance of the operator in implementing the emergency plan, plant procedures, and Technical Specification (TS) requirements. The inspectors also observed the post-simulator critique to assess the licensee's ability to identify operator or simulator performance issues.

b. Issues and Findings

No findings were identified.

1R12 Maintenance Rule Implementation

a. Inspection Scope

The inspectors sampled portions of selected structures, systems and components (SSCs), listed below, as a result of performance-based problems, to assess the effectiveness of maintenance efforts that apply to scoped SSCs. Reviews focused, as appropriate, on: (1) maintenance rule scoping in accordance with 10 CFR 50.65; (2) characterization of failed SSCs; (3) safety significance classifications; (4) 10 CFR 50.65 (a)(1) or (a)(2) classifications; and (5) the appropriateness of performance criteria for SSCs classified as (a)(2) or goals and corrective actions for SSCs classified as (a)(1). The selected SSCs were as follows:

- Control room chillers and chill water system due to chiller and chill water system failures
- The reactor coolant system loop ultrasonic level detectors, due to several detector failures upon entry into mid-loop operation
- Containment purge valves, due to failures following mid-loop operation
- Anderson-Greenwood relief valves used on the high pressure injection, low pressure injection, and low pressure service water systems, due to a relief valve sticking problem
- KHU sump pumps for Units 1 and 2, due to failure of the emergency sump pump

- Standby shutdown facility (SSF), due to failure of the ventilation system and lack of tracking of some operational data

b. Issues and Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

The inspectors evaluated, as appropriate for the selected SSCs listed below, (1) the effectiveness of the risk assessments performed before maintenance activities were conducted; (2) the management of risk; (3) that, upon identification of an unforseen situation, necessary steps were taken to plan and control the resulting emergent work activities; and (4) that maintenance risk assessments and emergent work problems were adequately identified and resolved. The following items were reviewed under this inspection procedure:

- KHU overhead power path taken out of service for maintenance and modification to KHU Unit 1

- The integrated emergency power test of KHU Units 1 and 2, the standby bus, and the main feeder busses

- Loss of turbine building flood protection measures

- Inadequate core cooling monitoring system, Unit 2, power failure

- Standby shutdown facility taken out of service for maintenance

- Ground on the direct current power system for Units 1, 2, and 3

- Unit 2 RCP seal leak off system isolation

- Turbine driven emergency feedwater pump maintenance and adjustment

- KHU overhead power path unplanned removal from service due to an unexpected emergency lockout of KHU Unit 2 during testing

The inspectors used the following licensee procedures for the reviews:

- Work Process Manual WPM-601, Revision 8, Innage Management

- Work Process Manual WPM-607, Revision 9, Maintenance Rule Assessment of Equipment Removed From Service

- Work Process Manual WPM-609, Revision 2, Innage Risk Assessment Using Oram-Sentinal

b. Issues and Findings

Unapproved Changes in Work Schedule

The inspectors identified a non-cited violation for failure to follow work control procedures when performing planned maintenance on Unit 3 Standby Breaker $S_{1-3}$. This resulted in a slightly increased likelihood of an initiating event while one of the emergency power supplies was degraded. In addition, a loss of the second emergency power supply occurred later that day while the first power supply was degraded.

Operators racked out and tagged Breaker $S_{1-3}$ at 4:55 a.m. on June 26, 2000, for planned maintenance that was scheduled to begin at 7:00 a.m. with completion anticipated approximately two hours later. Maintenance technicians assigned to the task, independently decided to delay working on Breaker $S_{1-3}$ and began a weekly preventive maintenance task on each unit's main exciter. The technicians did not inform the work window manager of the change. As a result of this decision, the potential to trip Unit 3 was increased while the underground emergency power path for that unit was degraded. Technicians completed the exciter maintenance on Unit 3 at approximately 11:30 a.m. Also, as a result the of delay in performance of the maintenance on Breaker $S_{1-3}$, it was still racked out at 12:52 p.m. when unrelated KHU testing resulted in an unexpected emergency lockout of KHU 2. The lockout resulted in loss of the overhead emergency power path and caused Unit 3 to enter TS 3.8.1 Condition I for both the underground and overhead emergency power paths becoming inoperable. Operators restored Breaker $S_{1-3}$ at 3:37 p.m. and the overhead path at 4:46 p.m. All emergency power path LCOs were met.

The inspectors and the regional senior reactor analysis evaluated the degradation in the emergency power supply and the impact on initiating event frequency using the significance determination process (SDP). During the Phase 1 screening the inspectors determined that redundant Unit 3 Standby Breaker $S_{2-3}$ and KHU 1 remained available and therefore the emergency power function was not completely lost. Therefore, the inspectors concluded that this issue was of low safety significance (Green). The Phase 1 screening on the increase in likelihood of a unit trip while the underground emergency power path was degraded determined that a Phase 2 screening was needed because both the initiating events and mitigating systems cornerstones were affected. The Phase 2 screening determined this issue was of low safety significance (Green) because even though the underground emergency power path for Unit 3 was degraded, the overhead path was available when maintenance technicians were working on the Unit 3 exciter. The increase in initiating event frequency did not increase the significance of a reactor trip given that the overhead power path was available.

Work Process Manual 601, Innage Management, Revision 8, required that the work window manager approve all schedule adjustments. Because maintenance technicians did not inform the work window manager of their decision to delay work on Breaker $S_{1-3}$ and commence preventive maintenance activities on the Unit 3 exciter, they were not in compliance with this procedure. The inspectors considered this a violation of TS 5.4.1 (Regulatory Guide 1.33, Appendix A, Paragraph 9e procedure). This is being treated as a NCV, consistent with Section VI.A of the enforcement policy and is identified as

NCV 50-269,270,287/00-05-03: Failure to Follow Work Control Procedures. This violation is in the licensee's corrective action program as PIP O-00-02375.

## 1R14 Personnel Performance During Nonroutine Plant Evolutions

### .1 Nonroutine Plant Evolutions

#### a. Inspection Scope

The inspectors reviewed, as described below, (1) personnel performance during selected non-routine events and/or transient operations, (2) licensee event reports focusing on those events involving personnel response to non-routine conditions, and (3) operator response after reactor trips which required more than routine expected operator responses, or which involved operator errors. As appropriate, the inspectors: (1) reviewed operator logs, plant computer data, or strip charts to determine what occurred and how the operators responded; (2) determined if operator responses were in accordance with the response required by procedures and training; (3) evaluated the occurrence and subsequent personnel response using the SDP; and (4) confirmed that personnel performance deficiencies were captured in the licensee's corrective action program. The non-routine evolutions reviewed during this inspection period included the following:

- Unit 3 plant shutdown activities for starting the Spring 2000 refueling outage
- Seal leak off isolation resulting in a four-hour TS limiting condition for operation (LCO)
- Unit 3 containment evacuation alarms during the Spring 2000 refueling outage
- Unidentified leakage in Unit 2 containment, resulting in a forced power reduction
- Flooding of the Unit 3 Train A low pressure injection (LPI) room with four inches of water
- Increased unidentified leakage in Unit 1 containment
- Mispositioning of Unit 3 LPI valve during the unit shutdown activities during the Spring 2000 refueling outage
- Smoke observed coming from the inside of the Unit 3 load center 3XA
- Steam leak in Unit 2 moisture separator reheater system

#### b. Issues and Findings

No findings were identified.

### .2 Power Escalation Results in Non-Conservative Nuclear Instruments

a. Inspection Scope

The inspectors reviewed personnel performance for the Unit 2 power escalation during the evening of April 19, 2000, and the morning of April 20, 2000, which resulted in the nuclear instruments becoming non-conservative. The inspectors attended the licensee's initial event review meeting, discussed the issues with licensee's management and staff, reviewed PIP O-00-01428, reviewed operating experience, and reviewed control room logs, nuclear instrument trend data, alarm response procedure OP/2/A/6102/005, NI Calibration Error, the Alarm Log Report, operating procedure OP/2/A/1102/004, Operation at Power, and station procedure PT/O/A/1103/020, Power Maneuvering Guidelines.

b. Issues and Findings

The inspectors identified a non-cited violation for an inadequate Oconee Station Procedure OP/2/A/1102/004, Operation At Power, Revision 59. The operators continued to increase reactor power after nuclear instrumentation became greater than 2 percent non-conservative which resulted in reactor protection system trips for nuclear overpower, reactor coolant pump to power, and nuclear overpower flux/flow imbalance subsequently being declared inoperable.

On April 19, 2000, at approximately 10:20 p.m., operators began increasing reactor power on Unit 2 from approximately 30 percent power following a repair inside the containment. The NIs had been calibrated at 30 percent reactor power and the licensee's maneuvering plan was to increase power at 18 percent per hour. The control rods, which were initially at 60 percent, were not moved significantly to control power during this transient. At 11:35 p.m., NI-7 initially became greater than 2 percent non-conservative to the thermal power best (NI-7 was at 49.6 percent and Thermal Power Best was at 52 percent). Operators continued the power increase and by 12:00 mid-night three of four channels of nuclear instrumentation had become greater than 2 percent non-conservative with respect to the thermal power best, which was now at 59.8 percent thermal power. The power increase continued until approximately 12:25 a.m. when thermal power reached 65 percent and control rods were inserted to maintain power. By 12:30 a.m., the nuclear instrument channels had become as much as 5.7 percent non-conservative to the thermal power best. Subsequently, operators declared all four NI channels inoperable, starting at 12:15 a.m. and maintenance completed re-calibration of all four channels of NIs by 2:55 a.m. on April 20, 2000.

The inspectors evaluated the results of this finding using the SDP. The inspectors noted that the non-conservative calibration of the nuclear instruments, resulted in not meeting the requirements (Allowable Values) specified in TS 3.3.1, Table 3.3.1-1 for (1)(a) Nuclear Overpower High Setpoint less than 105.5 percent reactor thermal power, (7) Reactor Coolant Pump to Power and (8) Nuclear Overpower Flux/Flow Imbalance. This resulted in an actual degradation in the function of the reactor protection system. However; the licensee's analysis confirmed that other trips were available to protect the reactor core and that these trips, although outside the allowable values would still function to protect the core for the various design basis accidents. Because the reactor protection system remained functional, the Phase 1 screening determined that the issue was considered to be of low safety significance (green).

Surveillance Requirement (SR) 3.3.1.2 states "Compare results of calorimetric heat balance calculation to the power range channel output and adjust the power range output if the calorimetric exceeds the power range channel output by greater than 2 percent reactor thermal power." The basis document for SR 3.3.1.2 states that "the control room operators monitor redundant indications and alarms to detect deviation in channel outputs." Oconee Station Procedure OP/2/A/1102/004, Operation At Power, Revision 59, Limits and Precautions, Section 2.10 requires that "if any two of four power range NIs are greater than 2 percent non-conservative, calibration is required to prevent exceeding safety limits." However, the procedure stated that, "If any two of the four NIs are not within 2 percent of core thermal power during power level increases, the core thermal power increase SHOULD be stopped and the NIs calibrated." The operators did not stop the power increase when all four NIs exceeded 2 percent since there was no requirement in the procedure. The Operations at Power procedure was inadequate in that it did not have a "SHALL" statement to require the operators to stop and recalibrate the NIs procedure. In addition, the Operation at Power procedure was deficient in that it did not inform the operators that the status-alarm, for NI calibration error, was bypassed during transient conditions. The inspectors considered this to be a violation of TS 5.4.1 (Regulatory Guide 1.33, Appendix A, Section 3 procedure). This issue is being treated as a NCV, consistent with Section VI.A of the enforcement policy and is identified as NCV 50-270/00-05-04: Inadequate Procedure for Operation At Power Results in Inoperable Reactor Protection System Trips. This violation is in the licensee's corrective action program as PIP O-00-01428.

.3 Over-Pressurization of the LPI System Suction Piping

a. Inspection Scope

The inspectors reviewed the control room logs, operating procedure OP/3/A/1102/001 (Controlling Procedure for Unit Startup), operating procedure OP/3/A/1104/005 (Reactor Building Spray (BS) System Operating Procedure), test procedure PT/3/A/0204/007 (Reactor Building Spray Pump Test Procedure), PIP O-00-01899, and interviewed operations personnel involved with the over-pressurization of the LPI suction piping.

b. Issues and Findings

The inspectors identified a non-cited violation for failure to verify that a working copy of a procedure was the latest revision, which resulted in an approximate 150 percent over-pressurization of the LPI/BS suction piping.

On May 14, 2000, during Unit 3 startup prior to going to Mode 4, with the LPI system in service and the reactor coolant system pressure of 285 pounds per square inch (psig), the LPI system and the BS systems were improperly realigned resulting in over-pressurization of a section of LPI/BS suction piping. This resulted in the LPI system suction relief valve lifting when valve 3LP-22 was opened and a loss of approximately 140 gallons of water from the reactor coolant system. Valve 3LP-22 was subsequently closed and the relief valve reseated although a small flange leak had developed. This section of LPI suction piping, which is shared with the BS system, has a design rating of 200 psig. The licensee calculated that with the reactor coolant system at 285 psig, the worst case pressure at the LPI suction piping would have been 307 psig during this event. The licensee concluded, based on the maximum code allowable piping pressure (442 psig), that the piping and valves were not over-stressed during this event. The licensee concluded that this event was the result of control room operators not using the latest revision of operating procedure OP/3/A/1104/005, Reactor Building Spray System. OP/3/A/1104/005 had been recently revised, but the revised copy had been misfiled in the control room procedure file and an inappropriate old revision of the procedure was obtained from a working file in the work control center. The operators subsequently failed to verify that the procedure they were going to use was the latest revision. The inspectors interviewed the operators and concluded that the error was not the result of schedule/time related pressure or emergent changes in outage plans.

The inspectors evaluated the results of this finding using the shutdown SDP. Because of the potential safety significance and the potential consequences of failure of the low pressure injection suction piping, the Phase 2 screening of this issue was performed by NRC headquarters. This issue was subsequently determined to have very low safety significance (green) due to the actual pressure not exceeding the allowable piping pressure.

NSD 704, Technical Procedure Use and Adherence, Revision 8, states, in part, that prior to use, working copies of procedures shall be verified by comparison with the control copy of the procedure. The failure to verify and use the latest revision of operating procedure OP/3/A/1104/005, resulted in over-pressurization of the LPI/BS suction piping and is considered to be a violation of TS 5.4.1 (Regulatory Guide 1.33, Appendix A, Section 1, Administrative Procedures). This issue is being treated as an NCV, consistent with Section VI.A of the enforcement policy and is identified as NCV 50-287/00-05-05: Failure to Use the Correct Revision to Plant Operating Procedures Results in Over-Pressurization of Low Pressure Injection Piping. This violation is in the licensee’s corrective action program as PIP O-00-01899.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed selected operability evaluations affecting risk significant mitigating systems, listed below, to assess, as appropriate, (1) the technical adequacy of the evaluations; (2) whether continued system operability was warranted; (3) whether other existing degraded conditions were considered; (4) if compensatory measures were involved, whether the compensatory measures were in place, would work as intended, and were appropriately controlled; (5) where continued operability was considered unjustified, the impact on TS LCOs. The inspectors reviewed the seven operability evaluations described in the following PIPs:

- PIP O-00-02141, Control room chillers operable with a six-second time delay relay to bypass the low oil level trip signal on chiller start

- PIP O-00-00688, Standby shutdown facility reactor coolant make up pump code testing, operable based on design input, the pressure, and the percentage of operating time at that pressure

- PIPs O-00-01959 and O-00-01960, code testing of Anderson-Greenwood relief valves, operable because, although the code requirements were not met, the relief valves would have lifted within the design basis of the systems

- PIP O-00-01748, Uninterruptible power supply for anticipated transients without a scram system not tested per design basis document, operable because the un-interruptible power supply was not required

- PIP O-99-03909, Emergency feedwater system operable with non-conformance with the current licensing basis

- PIP O-00-01899, Unit 3 LPI system pressurized over design on pump suction piping, operable because the over pressure did not exceed the code allowable

b. Issues and Findings

No findings were identified.

1R17 Permanent Plant Modifications

.1 Breaker Coil Modification

a. Inspection Scope

The inspectors performed a review of installed plant modifications to ensure that the design basis, licensing basis, and performance capability of risk significant systems, structures and components were not degraded through the modification and that the plant was not placed in an unsafe condition due to the modification. The inspector reviewed the modification issues of 25 volt direct current (vdc) rated coils versus the required 125 vdc being installed in the opening and closing circuits for various breakers and use of certain material while performing preventive maintenance on the containment purge valves. For the breaker coil issue, the inspectors reviewed the work histories, problem reports, Nuclear Station Modification NSM-53051, and discussed the issues with appropriate licensee personnel.

b. Issues and Findings

No findings were identified.

.2 Suitability of Materials for Sealing the Containment Purge Valves

a. Inspection Scope

The inspectors reviewed the surveillance testing, corrective maintenance history, and preventive maintenance history for the Units 1, 2, and 3 containment inlet and outlet purge valves and observed portions of surveillance testing and preventive maintenance on the Unit 3 outlet purge valves.

b. Issues and Findings

The inspectors identified a non-cited violation for failure to evaluate the compatibility and suitability of materials, used to help seal the containment purge valves, prior to installation and use of the materials on the containment purge valves.

Following higher than normal leakage rates, while performing purge valve leak rate testing during the Unit 1 forced outage in late February, the inspectors performed a detailed review of the purge valve corrective and preventive maintenance histories. The work order review noted that licensee maintenance personnel were routinely applying Dow Corning RTV DC-732 on various sections of the containment purge valves which included the purge valve hub seals, purge valve seats, and purge valve seat liners. The work orders indicated that RTV DC-732 had been applied during outages in 1994, 1995, 1997, and 1999. Visual examination of the Unit 3 purge inlet valves by the inspectors noted that RTV had actually been applied as indicated by the work orders to the seat liners, seat liner adjustment bolts, valve hub seals, and valve hubs. RTV was not found on the purge valve seats during these inspections. Discussions indicated that RTV had also been applied under the rubber seats when they were initially installed.

In addition, maintenance work orders indicated that DC-55 grease was routinely being applied to the valve seating surfaces. DC-55 is recommended for use as a pneumatic O-ring lubricant for “viton” O-ring seals in air operated valves. The manufacture’s grease literature indicated that the DC-55 grease should not be used on certain materials in that it could cause swelling and loss of tensile strength. It also indicated that more detailed testing should be performed on specific material prior to use. The grease manufacturer’s literature indicated that the ethylene-propylene (EPDM) purge valve seat would swell 5 percent instead of shrinking 3 percent and would have a loss tensile strength approximately 25 percent. Visual examination of the purge valves by the inspectors found that the DC-55 grease was being heavily applied to the interior of the valve disc and seat of purge valve 3PR-5.

When questioned about the use of RTV, the licensee stated that the RTV was being used to assist with the pressure boundary for the valve. The licensee had discussions with Dow Corning, who stated that "RTV DC-732 should not be applied on carbon steel because it does not necessarily remain bonded." The inspectors were provided information that indicated that the purge valve body, hub seals and seat liner bolting are fabricated from carbon steel. When questioned about the use of Dow Corning DC-55 lubricant, Dow Corning was contacted and stated that the "DC-55 would swell EPDM about 3 percent at room temperature and 6 percent at 155C." The grease manufacturer noted that the DC-55 would be acceptable on the hub seals. Although the licensee could provide information to show that both materials would maintain their characteristics under high temperature, humidity and radiation conditions, the licensee did not have information to show that the DC-732 would remain bonded to the carbon steel during a design basis accident and the licensee did not have information on the long term detrimental effects for loss of tensile stress on the valve seats due to the use of DC-55. The licensee stated that the procedures would be revised to prohibit the use of DC-732 and DC-55 on the containment purge valves.

The inspectors reviewed the valve manufacturer's technical manual and noted that the manufacturer only recommended a Dow Corning DC-111 lubricant for use in the purge valves. The valve manufacturer stated that the DC-111 grease was used primarily as a corrosion inhibitor and was chosen because of its ability to withstand high temperatures and because it produced no adverse effect on the EPDM seat. The manufacturer also stated that it was chosen for its anti-stick property and was recommended as a light coating for the seat grooves before installing a new rubber seat. The technical manual also recommended a light coating of DC-111 on the valve EPDM seat during routine preventive maintenance to prevent oxidation and hardening of the EPDM seat.

The inspectors evaluated the results of this finding using the SDP. Because the finding did not represent a significant actual open pathway in the physical integrity of the reactor containment, the Phase 1 screening determined that the issue was considered to be of very low safety significance (green).

10 CFR 50, Appendix B, Criterion III, Design Control, requires that measures shall be established for the selection and review for suitability of application of materials essential to the safety related functions of the structures, systems and components. This requirement is implemented by the Duke Energy Corporation Topical Report, dated May 20, 1999. Section 17.3.2.2, Design Control, of the Topical Report, states that for each proposed modification, the individual/organization assigned responsibility for evaluation and design of the modification considers the compatibility of materials and the suitability of application of materials essential to the function of the structure, system and components to be modified. Materials not recommended by the manufacturer (DC-732 and DC-55) have been routinely used to assist in sealing the containment purge valves since at least 1994 and the licensee had not evaluated the compatibility or the suitability of the materials for use on the containment purge valves. The failure to perform the evaluation prior to using the materials was considered to be a violation of 10 CFR, Appendix B, Criterion III. This issue is being treated as a NCV, consistent with Section VI.A of the enforcement policy and is identified as NCV 50-

269,270,287/00-05-06: Failure to Evaluate the Compatibility and Suitability of Materials Prior to Use on Containment Purge Valves. This violation is in the licensee's corrective action program as PIP O-00-01885.

1R19 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed post-maintenance test (PMT) procedures and/or test activities, as appropriate, for selected risk significant mitigating systems to assess whether: (1) the effect of testing on the plant had been adequately addressed by control room and/or engineering personnel; (2) testing was adequate for the maintenance performed; (3) acceptance criteria were clear and adequately demonstrated operational readiness consistent with design and licensing basis documents, (4) test instrumentation had current calibrations, range, and accuracy consistent with the application, (5) tests were performed as written with applicable prerequisites satisfied; (6) jumpers installed or leads lifted were properly controlled; (7) test equipment was removed following testing; (8) and that equipment was returned to the status required to perform its safety function. The inspectors observed testing and/or reviewed the results of the following tests:

- PT/3/A/0152/12, Low Pressure Injection System Valve Stroke Test, Revision 14, Enclosure 13.3, Page 11 and 12, valve 3LP-9, 3C LPI Pump discharge valve to train A, Attachment 1 - VST Datasheet, Page 2; IP/0/A/3001/11B, Revision 21, Testing Motor Operated Valves Using VOTES; and IP/0/A/3001/11H, Revision 0, Differential Pressure Testing Using VOTES

- PT/3/A/0152/12, Low Pressure Injection System Valve Stroke Test, Revision 14, Enclosure 13.3, Page 13 and 14, valve 3LP-10, 3C LPI Pump discharge valve to train B, Attachment 1 - VST Datasheet, Page 2; IP/0/A/3001/11B, Revision 21, Testing Motor Operated Valves Using VOTES; and IP/0/A/3001/11H, Revision 0, Differential Pressure Testing Using VOTES

- PT/3/A/0152/12, Low Pressure Injection System Valve Stroke Test, Revision 14, Enclosure 13.3, Page 24 and 25, valve 3LP-17, LPI Train A low pressure injection valve, Attachment 1 - VST Datasheet, Page 5; IP/0/A/3001/11B, Revision 21, Testing Motor Operated Valves Using Votes; and IP/0/A/3001/11H, Revision 0, Differential Pressure Testing Using VOTES

- PT/3/A/0152/12, Low Pressure Injection System Valve Stroke Test, Revision 14, Enclosure 13.3, Page 26 and 27, valve 3LP-18, LPI Train B low pressure injection valve, Attachment 1 - VST Datasheet, Page 6; IP/0/A/3001/11B, Revision 21, Testing Motor Operated Valves Using Votes; and IP/0/A/3001/11H, Revision 0, Differential Pressure Testing Using VOTES

- TN/ 1/A/3049/00/AL1, Revision 1, Keowee Unit 1 relay change out and test

- Equipment Room Chill Water supply valve 1WC-191 repair per Work Order 98185574.

b. Issues and Findings

Inadequate Testing of Chill Water System Automatic Supply Valve

The inspectors identified a non cited violation for failure to properly implement procedures to calibrate the controls to Unit 1 equipment room chilled water valve 1WC-191 following replacement of the valve. This resulted in a failure to supply cooling water to one air handling unit for the Unit 1 equipment room.

During a plant status tour on March 28, 2000, the inspectors observed that the temperature in the Unit 1 equipment room was 5 degrees higher than Units 2 or 3 equipment rooms and that the chilled water inlet and outlet temperatures for AHU-22, which supplies one train of cooling for the Unit 1 equipment room, were both equal at about 76 degrees F. When questioned about this, the licensee found that valve 1WC-191 was closed with the valve controller providing a 20 psig close signal to the valve which was designed with a proportional band for a 4 to 8 psig signal. Further investigation revealed that the valve had been removed from service on March 8, 2000, replaced on March 9, 2000, and that the work order had only specified a visual leak check as the post-maintenance test. No calibration of the replaced valve was specified. On March 29, 2000, the licensee calibrated the controller for proper operation with the new valve. The inspectors verified that AHU-34, which is the second train of cooling for the Unit 1 equipment room, had remained in service from March 8 to 29, 2000.

The inspectors evaluated this finding using the significance determination process and found it to be of very low safety significance because AHU-34 had remained operable during the period that AHU-22 was not functioning (green).

NSD 408, Testing, Revision 8, required that post-maintenance testing be performed to verify that a structure, system, or component is capable of performing its function. The failure to specify the proper calibration for the replacement valve was contrary to NSD 408 and was considered to be a violation of TS 5.4.1 (Regulatory Guide 1.33 Appendix B, Paragraph 8a). This is being treated as an NCV, consistent with Section VI.A of the enforcement policy and is identified as NCV 50-269/00-05-07: Inadequate Post-Maintenance Testing of Chill Water Supply Valve to Equipment Room Cooler. This violation is in the licensee’s corrective action program as PIP O-00-01137.

1R20 Refueling and Outage Activities

a. Inspection Scope

The inspectors conducted reviews and observations for selected licensee outage activities to ensure that the licensee considered risk in developing the outage plan, the licensee adhered to the outage plan to control plant configurations based on risk, that mitigation strategies were in place for losses of key safety functions, and that the licensee adhered to operating license and technical specification requirements. Between April 13, 2000, and May 19, 2000, the inspectors reviewed the following activities related to the refueling outage on Unit 3 for conformance to the applicable procedure and witnessed selected activities associated with each evolution:

- Reactor cooldown and initiation of decay heat removal
- Mid-loop operations to install and remove steam generator nozzle dams
- RCS level instrument calibrations
- Fuel pool cooling alignment
- Fuel pool cooling temperature and flow
- Containment closure
- Electrical power alignments and testing
- Condenser waterbox isolation
- Fuel movement
- Reactor startup
- Zero power physics testing

The inspectors also walked down the Unit 3 containment during hot standby conditions prior to reactor startup.

b. Issues and Findings

Failure to Maintain One Train of LPI Operable While In Mode 4

The inspectors identified a non cited violation on Unit 3 for failure to maintain one train of LPI operable in the emergency core cooling system (ECCS) mode during Mode 4.

On April 13, 2000, Unit 3 entered Mode 4 as planned for the refueling outage. Upon entering Mode 4, at approximately 8:45 p.m., operators closed ECCS sump suction valves 3LP-19 and 3LP-20 in order to align the LPI system for decay heat removal. In addition, the inspectors noted that the operators opened the power supply breakers to the valves and tagged the breakers open. TS 3.5.3 allowed a train of LPI to be considered operable if it was capable of being manually realigned to its ECCS mode of operation. The operators concluded that by retaining control of the tags they could restore power to the valves for subsequent control room operation and hence met the requirement of TS 3.5.3.

TS 3.5.3 requires one train of LPI be operable for ECCS operation while in Mode 4. Note 2 to TS 3.5.3 allows a train of LPI to be considered operable if it can be manually realigned for ECCS operation. The basis for TS 3.5.3 states that an LPI train is operable for ECCS if it includes the capability to manually (remotely) transfer suction to the reactor building sump. The inspectors determined that tagging out the power supply for Valves 3LP-19 and 3LP-20 made both valves inoperable because they would not be capable of remote operation, i.e., from the control room. Also, the TS did not contain a provision for allowing retention of tags by operators as an alternative to the ability to remotely operate the valves when required. Therefore, the one required train of LPI was not operable for ECCS operation in Mode 4. Unit 3 entered Mode 5, where TS 3.5.3 was not applicable, at 1:55 a.m. on April 14, 2000.

The inspectors performed the initial screening of this issue using the shutdown SDP. This issue was determined to have very low safety significance (green) because the operators had control of the danger tags and could have energized the valve operator breakers if required. In addition, it was determined to have very low safety significance because of the reduced reactor coolant temperatures and the short duration that the valves were inoperable.

TS 3.5.3 Condition D required immediate restoration if the one required LPI train was inoperable while in Mode 4. Because the operators did not restore one train of LPI immediately, the removal of power from the breakers for 3LP-19 and 3LP-20 was a violation of TS 3.5.3. This is being treated as an NCV, consistent with Section VI.A of the enforcement policy and is identified as NCV 50-287/00-05-08: Low Pressure Injection System Inoperable in Mode 4 Due to Removal of Control Power from Containment Sump Valves Supply Breakers. This violation is in the licensee's corrective action program as PIP O-00-01906.

## 1R22 Surveillance Testing

### .1 Routine Surveillance Tests

#### a. Inspection Scope

The inspectors witnessed surveillance tests and/or reviewed test data of selected risk-significant SSCs, listed below, to assess, as appropriate, whether the SSCs met TS, UFSAR, and licensee procedure requirements, and to determine if the testing effectively demonstrated that the SSCs were operationally ready and capable of performing their intended safety functions. The following testing was observed and/or reviewed:

- PT/2/A/0400/07, Revision 34, SSF RCS Make Up Pump Test, Unit 2
- PT/1/A/0151/19 and 20, Revision 5, Penetrations 19 and 20 Leak Rate Tests, Unit 1
- PT/0/A/0620/09, Revision 19, Keowee Hydro Plant Operation, Units 1 and 2 (or TT/0/A/0620/45, Revision 1, Keowee Uncertainty Test - Overspeed)
- PT/0/A/0620/16, Revision 26, Keowee Hydro Plant Emergency Start, Units 1 and 2
- PT/3/A/0151/19 and 20, Revision 4, Penetrations 19 and 20 Leak Rate Tests, Unit 3

b. Observations and Findings

No findings were identified.

.2 Anderson Greenwood Relief Valve Testing Problems

a. Inspection Scope

The inspectors reviewed the results of relief valve testing for the thermal relief valves (Anderson Greenwood) which were installed on the HPI system, LPI system, and low pressure service water (LPSW) system. The inspection included a review of the as-found and as-left testing in accordance with the American Society for Mechanical Engineers (ASME), Section XI, OM-1, a review of the equipment problem history documented in the licensee's PIP program, and discussions regarding the testing failures with engineering personnel. The inspectors also reviewed Oconee Inservice Testing Program OM, Part 1, MP/0/1200/148A, Revision 11, Anderson-Greenwood Model 81P Relief Valve Testing and Corrective Maintenance.

b. Issues and Findings

The inspectors identified a non-cited violation for failure to refurbish or to replace relief valves that had failed to meet their respective acceptance criteria. The inspectors identified a second non-cited violation for establishing improper test acceptance criteria which did not meet the ASME code design requirements for ensuring that relief valves would achieve rated lift capability at less than 10 percent above system design.

In early April 2000, discussions with the licensee indicated that many relief valves, manufactured by Anderson Greenwood, installed on the HPI, LPI, and LPSW systems, were sticking and were not opening within the required acceptance band. PIP O-97-03373, initiated on October 6, 1997, indicated that 86 Anderson Greenwood relief valves could be affected. Review of the Unit 3 test results and discussions with the component engineer indicated that the relief valves were routinely sticking which resulted in the initial test being approximately 5-6 percent high. The inspectors noted that subsequent testing would be within the test acceptance criteria and the licensee would then return the valves to service without resolving the sticking problem. Discussions indicated that the licensee has been working with the manufacturer to resolve the problem for a number of years with no success. The result of the sticking problem was that the relief valves would not meet the plus or minus 3 percent tolerance specified in ASME NC-7614.2 for popping/relief pressure tolerance. To resolve this problem with not meeting the code requirements, the licensee, in some cases, inappropriately raised the acceptable tolerance by as much as 20 percent.

The inspectors also noted that based on the approved testing methodology that the relief valves would pop open/relieve (attain rated lift capacity) at approximately 107 percent of design when operating properly. However, with the relief valve sticking problem, 13 of 18 valves tested during the Unit 3 refueling outage had lift (pop open/relief) pressures greater than 110 percent of design during the first test. This condition did not meet the design requirements specified by ASME code, Section NC-7614, which requires that “liquid relief valves shall attain rated lift at a pressure not greater than 10 percent above set pressure.”

The inspectors screened the results of these findings using the SDP. The inspectors noted that with the identified relief valves not lifting as required, the various sections of HPI, LPI and LPSW piping could be subjected to cyclic pressure stresses above design (greater than 100 percent) when isolated and over an extended period could result in fatigue failure of the piping. The inspectors concluded that this issue resulted in a degraded condition and did not cause a loss of function. Because the HPI, LPI, and LPSW systems remained operable with degraded functioning relief valves, the Phase 1 screening determined that the issue was considered to be of low safety significance (green).

Relief valve testing conducted per ASME Section XI, OM-1987, Part 1, Section 7.4.2.2.(b) requires that “valves which do not comply with their respective acceptance criteria (lift at a pressure within the owner specified pressure tolerance) shall be refurbished in accordance with written procedures or replaced.” Contrary to this requirement, seven Unit 3 Anderson Greenwood 81P relief valves, tested during the Unit 3 refueling outage in April 2000, failed to lift within the owner specified pressure tolerance (prescribed acceptance criteria) and the valves were not refurbished to resolve the sticking problem nor were the valves replaced. This failure to meet the relief valve testing requirements of ASME code, Section XI, Testing of Pumps and Valves, OM-1, is considered a violation of TS 5.5.9, Inservice Testing Program. This violation is being treated as an NCV, consistent with Section VI.A of the enforcement policy and is identified as NCV 50-287/00-05-09: Failure to Meet ASME, Section XI, OM-1 Testing Requirements for Refurbishment or Replacement of Valves Following Test Failure. This violation is in the licensee’s corrective action program as PIP O-97-03567.

NUREG 1482 provides guidance to licensees for changing the ASME specified relief valve lifting tolerances provided the licensee has performed an evaluation that justifies the change. The licensee, in some cases, changed the ASME specified relief valve lifting tolerances from -3% to +3% to values of -3% to +20%. However; this change in the relief valve lift tolerance was not justified by the evaluation in that the evaluation did not consider the system design requirements specified by ASME Article NC-7000. NC-7000 Article NC-7000 of the ASME code for the design requirements of piping systems for protection against overpressure, Section NC-7411, Relieving Capacity of Pressure Relief Devices, requires that “relief devices intended for overpressure protection of the system...shall be sufficient to prevent a rise in pressure more than 10 percent above system design pressure at design temperature...” In addition, ASME code NC-7614.1 requires that “liquid relief valves shall attain rated lift at a pressure not greater than 10 percent above set pressure.” Contrary to these requirements, the licensee had established inappropriate acceptance criteria (some as much as 20 percent above the set pressure). The failure to establish appropriate acceptance criteria is contrary to the requirements of Article NC-7400 of the ASME code for Protection Against Overpressure, and therefore, in violation of TS 5.5.9. This violation is being treated as an NCV, consistent with Section VI.A of the enforcement policy and is identified as NCV 50-287/00-05-10: Inappropriate Acceptance Criteria Established for Relief Valve Testing. This violation is in the licensee’s corrective action program as PIP O-00-02460.

.3 Unit 1 Containment Purge Valve Testing Failures

a. Inspection Scope

The inspectors reviewed control room logs, completed containment purge valve surveillances, completed containment purge valve work orders and discussed test failures with engineering personnel for the Unit 1 containment purge valve testing failures on February 22, and February 28, 2000.

b. Issues and Findings

Towards the end of a Unit 1 outage to repair a RCS loop drain line through wall leak, containment purge valves 1PR-5 and 6 and 1PR-1 and 2 were tested per Selected Licensee Commitment (SLC) 16.6.9, because they had been cycled to allow ventilation of the reactor building. When containment purge penetrations 19 and 20 were tested on February 28, 2000, and February 22, 2000, respectively, the licensee was unable to pressurize the penetrations. Discussions indicated that the penetrations could not be pressurized to 10 psig (design 60 psig). However; the actual pressures achieved and the leak rates that were observed were not documented in the test results. Given the leak rate conditions of the penetrations, the inspectors questioned the ability of the valves to function as containment closure devices during the just completed forced outage maintenance activities on the RCS drain line and during replacement of three reactor coolant pump seals. Reduced inventory activities were entered at 7:18 p.m. on February 19 and exited at 8:40 p.m. on February 26, 2000. Reactor coolant pump seal replacement activities, in addition to the drain line repair, resulted in RCS drain down conditions from 2:19 p.m. on February 19 until 6:56 p.m. on February 27. The steam generator manways were reinstalled at 10:35 p.m. on February 27, 2000.

During outages in which containment work activities are expected, the licensee opens the purge valves to ventilate containment. At the end of the outage, the licensee performs iterative leak testing on the valves (performing adjustments and preventive maintenance that procedurally authorizes grease and RTV as required) until acceptable leakage results are achieved. From that point on, until the end of the operating cycle, the valves are not disturbed (baring an interim outage requiring containment ventilation).

The inspectors noted that if an event occurred with the plant in a reduced inventory or mid-loop condition, the licensee's long-standing practice of iteratively adjusting and sealing the purge valves could not be relied upon to seal the penetrations in that access to the valves would be prohibited. The licensee's operability evaluation (performed following the testing of February 28, 2000) concluded that valve cycling and preventive maintenance performed prior to the testing caused the observed failures in the valve leak rate testing. The licensee did not initiate a problem report for the February 22, 2000, purge valve penetration failure, so an operability evaluation was not performed for this failure. The inspectors noted that the valves had only been cycled prior to testing on February 22 and 28, 2000; the preventive maintenance, as well as the subsequent readjustments to the valve seats to get the valves to pass, the leak rate test was not performed until later.

Pending additional NRC review of operating in mid-loop with purge valves that subsequently failed to hold design pressure, this will be identified as URI 50-269/00-05-11: Operation in Mid-Loop with Containment Purge Valves that Subsequently Failed to Hold Design Pressure.

.4 Surveillance for Response Time Testing of Keowee Units

a. Inspection Scope

The inspectors reviewed the response time testing of the Keowee hydro units specified by Technical Specification (TS) Surveillance Requirement (SR) 3.8.1.9. This review was performed using station procedures PT/0/A/0610/022, (Degraded Grid, Switchyard Isolation and Keowee Over Frequency Protection Functional Test, dated October 30), 1999), PT/0/ A/0620/016, (Keowee Hydro Emergency Start Test, dated July 16, 1999), TT/0/A/0620/016, (Keowee Uncertainty Test-Overspeed Start Test, dated June 30, 2000), and TT/0/A/0620/039, (Keowee Unit 2 Governor Overshoot Reduction Test, dated January 7, 2000).

b. Issues and Findings

The inspectors noted that during the test, the frequency of both Keowee hydro units exceeded the 63 hertz specified in SR 3.8.1.9. This surveillance requires that the KHU be available to carry load in less than 23 seconds and achieves 57-63 hertz. However; the inspectors noted that during surveillance testing, the licensee stops timing when the Keowee unit reaches approximately 60 hertz, although, subsequently the unit exceeds the 63 hertz limit and reaches approximately 70 hertz. During the test, the unit did not return to 57-63 hertz until approximately 28 seconds. This practice did not appear to be appropriate and was discussed and reviewed with the licensee. The licensee stated this practice was acceptable and that clarification to the TS surveillance requirement would be made and submitted to NRC headquarters for review during the third quarter of 2000.

The inspectors noted that the licensee was performing additional testing of the Keowee units to establish better hydro gate control, had proposed modifications to the Keowee unit governor, and would be installing automatic trip circuitry for load protection for greater than 66 hertz operation. Pending additional NRC review, the issue of potentially not meeting the surveillance requirements of SR 3.8.1.9 will be identified as URI 50-269,270,287/00-05-12: Potential Inadequate Surveillance Testing of Keowee Hydro Units. This issue is in the licensee's corrective action program as PIP O-00-00783.

1R23 Temporary Plant Modifications

Flooding in LPI Room

a. Inspection Scope

The inspectors conducted a review of a temporary modification to ensure that it did not have an adverse affect on the safety functions of important safety systems. The inspectors reviewed the implementation of a temporary modification to provide power to the sump pumps in LPI Room 82 during the Unit 3 refueling outage. Incomplete implementation of this modification resulted in partial flooding of the room.

b. Issues and Findings

On April 22, 2000, the licensee began draining the Unit 3 borated water storage tank (BWST) to the sump in LPI Room 82. The normal power supply to the sump pumps was deenergized and a modification to connect temporary power to the pumps was signed off as complete. However, the modification had only been implemented in one of the LPI rooms, not Room 82. Therefore, when the sump in Room 82 filled, there was no power for the sump pumps to remove the water and the room flooded to a depth of approximately 4 inches before operators stopped the draining.

The inspectors evaluated the results of this finding using the shutdown SDP. At the time the flooding occurred, Unit 3 was in Mode 6 with the reactor cavity filled and LPI Pump 3A operating in the decay heat removal mode. LPI Pump 3B was unavailable due to work on the pump and injection valve. LPI Pump 3C was available but the discharge valves were tagged out for modification work. The remaining LPI Pump 3A is located in Room 82. The inspectors verified that the flooding did not directly impact LPI operation. However, if the flooding continued a potential impact did exist because the bottom of the LPI motor was 24 inches above the floor and access paths to the other LPI room and the HPI room were approximately 53 inches above the floor. At the close of this inspection period, NRC personnel were still assessing the risk associated with this issue.

The inspectors noted that PIP O-99-04661 had been initiated on November 18, 1999, following similar events during outages on both Unit 1 and Unit 2. The corrective actions for that PIP included taking extra care during the planning stage of the outage to ensure that temporary power installation was not scheduled during times when the LPI room sumps were needed. The inspectors determined that this corrective action was not adequate to correct the problem from the previous outages and was therefore a potential violation of 10 CFR 50, Appendix B, Criteria XVI. Pending additional NRC review of the risk associated with this issue, the LPI room flooding is identified as an unresolved item URI 50-287/00-05-13: Inadequate Corrective Action to Prevent Low Pressure Injection Room Flooding. This issue is in the licensee's corrective action program as PIPs O-00-02099, O-00-02100, and O-00-02101.

**Cornerstone: Emergency Preparedness**

1EP1 Exercise Evaluation

a. Inspection Scope

The inspectors reviewed the objectives and scenario for the Oconee Nuclear Site biennial, full-participation emergency preparedness 2000 exercise to determine whether they were designed to suitably test major elements of the licensee's emergency plan. (See Attachment 2 for a narrative of the exercise.)

During the period June 12-15, 2000, the inspectors observed and screened the licensee's performance in the exercise, as well as selected activities related to the licensee's conduct and self-assessment of the exercise. The exercise was conducted on June 12, 2000, from 7:00 p.m. to 9:30 p.m., and on June 13, 2000, from 8:00 a.m. to 12:26 p.m. Licensee activities inspected during the exercise included those occurring in the control room simulator, technical support center, operational support center, and emergency operations facility. The NRC's evaluation focused on the risk-significant activities of event classification, notification of governmental authorities, onsite protective actions, offsite protective action recommendations, and accident mitigation. The inspectors also evaluated command and control, the transfer of emergency responsibilities between facilities, communications, adherence to procedures, and the overall implementation of the emergency plan. The inspectors attended the post-exercise critique to evaluate the licensee's self-assessment process, as well as the presentation of critique results to plant management.

b. Issues and Findings

No findings were identified.

1EP6 Drill Evaluation and Simulator Observations

a. Inspection Scope

The inspectors observed an emergency response organization practice drill conducted on April 4, 2000, and observed simulator scenarios on April 12, 2000, to observe licensee performance in the area of emergency preparedness, and to assess the licensee's critique of those performances. The inspectors specifically verified the proper classification of events during the simulations. These observations were made in the control room simulator, technical support center, operations support center, and in the applicable portions of the plant.

b. Issues and Findings

No findings were identified.

## 2. RADIATION SAFETY

### Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiological Significant Areas

a. Inspection Scope

The inspectors performed plant walkdowns of radiological control areas; reviewed selected radiation work permits; evaluated worker knowledge of radiation work practices; observed package labels; and postings and control of access to radiological control areas high radiation areas and extra high radiation areas. Independent boundary and contamination control surveys were performed by the inspectors. Selected survey instruments, electronic pocket dosimeters, friskers, small article monitors and portal monitor calibrations, source checks and operability were independently verified. Selected health physics identified items in the licensee's Problem Investigation Process were reviewed for assignment, closeout timeliness and trending.

b. Issues and Findings

No findings were identified.

2OS2 As Low As Reasonably Achievable (ALARA) Planning and Controls

a. Inspection Scope

The inspectors reviewed the Unit 3 End-Of-Cycle 18 refueling outage collective exposure, shutdown chemistry crud bursts, and clean-up results. The inspectors reviewed ALARA work plan dose estimates and dose controls used to track and minimize worker doses for the following outage activities: steam generator eddy current testing, tube plugging, installation/removal of lead shielding, installation of cold leg drain line plug, installation/removal of nozzle dams, steam generator platform set-up, steam generator man-way removal, and erection/removal of scaffolds. The preparation, survey and removal of outage equipment through the containment equipment hatch were also observed. The inspectors reviewed ALARA emergent work planning, including the Unit 3 reactor building annulus inspection (Radiation Work Permit Number 3026), work controls, and worker doses. The inspectors observed workers performing maintenance activities and the use of shielding packages and work site engineering controls. The inspectors independently verified dose rates, area surveys, and postings at selected locations. Licensee procedures and worker files for declared pregnant workers were reviewed.

b. Issues and Findings

No findings were identified.

2OS4 Operation of an Independent Spent Fuel Storage Installation (ISFSI)

a. Inspection Scope

The inspectors independently verified radiation surveys for the ISFSI. A daily security inspection of ventilation screens and roof slab temperature inspection was observed. ISFSI environmental thermoluminescent dosimetry data was reviewed and 10 CFR 72.106 Controlled Area of an ISFSI compliance was verified. Operation of continuous air monitors, air samplers and the portable radiation bridge monitor was observed in the Unit 3 Spent Fuel Building. Fuel shuffle and pre-staging of selected spent fuel to be loaded in the spent fuel cannister was observed. Decontamination and surveys of the cask, installation of the bottom seal plate and leak check, lubrication of the cask rails and cask and canister placement in the decontamination pit was observed. The inspectors observed cold fit-up of the top radiation shield and two cask cover plates.

b. Issues and Findings

No findings were identified.

## 4. OTHER ACTIVITIES

4OA2 Performance Indicator (PI) Verification - Emergency Preparedness

PIs were verified in accordance with the guidance contained in Section 2.4, Emergency Preparedness Cornerstone, of NEI 99-02, Revision 0, Regulatory Assessment Performance Indicator Guideline.

.1 Emergency Response Organization (ERO) Drill/Exercise Performance PI

a. Inspection Scope

The inspector assessed the accuracy of the performance indicator for ERO drill and exercise performance through review of documentation from first quarter 1999 to first quarter 2000.

b. Issues and Findings

No findings were identified.

.2 ERO Drill Participation PI

a. Inspection Scope

The inspector assessed the accuracy of the PI for ERO drill participation from first quarter 1999 to first quarter 2000 by review of approximately 10% of the training records for the 139 personnel assigned to key positions in the ERO.

b. Issues and Findings

No findings were identified.

.3 Alert and Notification System Reliability PI

a. Inspection Scope

The inspector assessed the accuracy of the PI for the alert and notification system reliability through review of the licensee's records of the siren tests for the first quarter of 2000.

b. Issues and Findings

No findings were identified.

4OA3 Event Follow-up

a. Inspection Scope

The inspectors evaluated plant status and mitigating actions of the following events, listed below, to assess the need for an Incident Investigation Team (IIT), Augmented Inspection Team (AIT), or Special Inspection (SI). Specifically, the inspectors, as appropriate, (1) observed plant parameters and status, (2) evaluated the performance of mitigating systems and licensee actions, (3) confirmed that the licensee properly classified the event and made timely notifications to the NRC and state/county governments as required, (4) communicated details regarding the event to risk analysts and others in Region and Headquarters offices for use in determining risk significance and NRC reactive response to the event, and (5) verified that licensee event reports were accurate and consistent with NRC observations, such as in reports of ITTs, AITs, and SIs. The inspectors initially reviewed the following events/issues under this inspection procedure:

- Non-conservative nuclear instruments, during rapid power increase, resulting in inoperable reactor protection system trips for nuclear overpower, reactor coolant pump to power, and nuclear overpower flux/flow imbalance.

- Minor earthquake in the area of the Jocassee dam.

- Automatic lockout of the emergency AC overhead power path during testing of Keowee Unit 2.

b. Issues and Findings

No findings were identified and documented through this inspection activity. Findings were identified and documented in other sections of this report, through other inspection activities, for a nuclear instrument issue (Section 1R14) and for an automatic lockout (Section 1R13).

4OA6 Meetings

.1 Exit Meeting Summary

The inspectors presented the inspection results to Mr. J. Forbes, Station Manager, and other members of licensee management at the conclusion of the inspection on July 5, 2000. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

.2 Predecisional Enforcement Conference Summary

On April 25, 2000, a predecisional enforcement conference (EA 98-543) was held in the Region II Office with the licensee to discuss seven apparent violations (EEIs) related to the emergency feedwater (EFW) system design (EEIs 50-269,270,287/99-13-01 through -07). The apparent violations were identified prior to the April 1, 2000, implementation of the Revised Oversight Process (ROP) and were therefore dispositioned under the previous enforcement policy. Following the conference, a letter was sent to the licensee on May 9, 2000, describing the NRC's conclusions with respect to the seven apparent violations. The NRC concluded that the issues described in the seven apparent violations represented five violations of NRC regulations. Also, the NRC applied enforcement discretion and risk mitigation considerations in concluding that none of the five violations would be cited. No colors were assigned to the violations. Accordingly, the seven EEIs are closed and the five NCVs will be identified as:

- NCV 50-269,270,287/00-05-14: Past EFW System Design Was Not Functional for a Main Feedwater Line Break and Was Not Reported or Adequately Corrected

- NCV 50-269,270,287/00-05-15: Insufficient Water Sources for EFW System

- NCV 50-269,270,287/00-05-16: EFW System Single Failure Vulnerability and Inadequate 10 CFR 50.59 Safety Evaluation

- NCV 50-269,270,287/00-05-17: Inadequate EFW System Seismic Boundary

- NCV 50-269,270,287/00-05-18: Inadequate 10 CFR 50.59 Safety Evaluation for

UFSAR Change That Reduced EFW System Design Criteria

The NRC letter of May 9, 2000, also indicated that the risk assessment associated with insufficient water sources for the EFW system (NCV 50-269,270,287/00-05-15) did not take into consideration a potential vulnerability associated with the effect of a high energy line break on the 4-kilovolt (KV) safety-related electrical busses. Specifically, a high energy line break in the turbine building could cause a loss of the three 4KV safety-related electrical busses, failure of all ECCS, and loss of RCP seal cooling. This potential vulnerability has not been thoroughly evaluated with respect to the probability of occurrence of the event or with respect to the potential for consequential RCP seal failures and a loss of coolant accident. The potential vulnerability could represent an increase in core damage frequency over that described in the Oconee Probabilistic Risk Assessment. The licensee stated at the conference its intent to conduct additional high energy line break analyses related to this potential vulnerability. The NRC letter stated that this potential vulnerability will be identified as an unresolved item. This issue is identified as URI 50-269,270,287/00-05-19: Potential Vulnerability of a High Energy Line Break Causing a Loss of the Three 4KV Safety-Related Electrical Busses.

## PARTIAL LIST OF PERSONS CONTACTED

Licensee
T. Coutu, Superintendent of Operations
T. Curtis, Mechanical System/Equipment Engineering Manager
J. Forbes, Station Manager
W. Foster, Safety Assurance Manager
D. Hubbard, Modifications Manager
C. Little, Civil, Electrical& Nuclear Systems Engineering Manager
W. McCollum Site Vice President, Oconee Nuclear Station
B. Medlin, Superintendent of Maintenance
M. Nazar, Manager of Engineering
L. Nicholson, Regulatory Compliance Manager
M. Thorne, Emergency Preparedness Manager
J. Twiggs, Manager, Radiation Protection
J. Weast, Regulatory Compliance

NRC
D. LaBarge, Project Manager

## ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

| | | |
|---|---|---|
| 50-269/00-05-11 | URI | Operation in Mid-Loop with Containment Purge Valves that Subsequently Failed to Hold Design Pressure (Section 1R22.3) |
| 50-269,270,287/00-05-12 | URI | Potential Inadequate Surveillance Testing of Keowee Hydro Units (Section 1R22.4) |
| 50-287/00-05-13 | URI | Inadequate Corrective Action to Prevent Low Pressure Injection Room Flooding (Section 1R23) |
| 50-269,270,287/00-05-19 | URI | Potential Vulnerability of a High Energy Line Break Causing a Loss of the Three 4KV Safety-Related Electrical Busses (Section 4OA6.2) |

Opened and Closed During this Inspection

| | | |
|---|---|---|
| 50-269,270/00-05-01 | NCV | Failures of RCP Oil Collection System to Collect Oil (Section 1R05.3) |
| 50-269,270/00-05-02 | NCV | Failure to Report Conditions Outside of Appendix R Design Basis (Section 1R05.3) |
| 50-269,270,287/00-05-03 | NCV | Failure to Follow Work Control Procedures (Section 1R13) |
| 50-270/00-05-04 | NCV | Inadequate Procedure for Operation At Power Results in Inoperable Reactor Protection System Trips (Section 1R14.2) |
| 50-287/00-05-05 | NCV | Failure to Use the Correct Revision to Plant Operating Procedures Results in Over-Pressurization of Low Pressure Injection Piping (Section 1R14.3) |
| 50-269,270,287/00-05-06 | NCV | Failure to Evaluate the Compatibility and Suitability of Materials Prior to Use on Containment Purge Valves (Section 1R17.2) |

| | | |
|---|---|---|
| 50-269/00-05-07 | NCV | Inadequate Post-Maintenance Testing of Chill Water Supply Valve to Equipment Room Cooler (Section 1R19) |
| 50-287/00-05-08 | NCV | Low Pressure Injection System Inoperable In Mode 4 Due to Removal of Control Power from the Containment Sump Valves Supply Breakers (Section 1R20) |
| 50-287/00-05-09 | NCV | Failure to Meet ASME, Section XI, OM-1 Testing Requirements for Refurbishment or Replacement of Valves Following Test Failure (Section 1R22.2) |
| 50-287/00-05-10 | NCV | Inappropriate Acceptance Criteria Established for Relief Valve Testing (Section 1R22.2) |
| 50-269,270,287/00-05-14 | NCV | Past EFW System Design Was Not Functional for a Main Feedwater Line Break and Was Not Reported or Adequately Corrected (Section 4OA6.2) |
| 50-269,270,287/00-05-15 | NCV | Insufficient Water Sources for EFW System (Section 4OA6.2) |
| 50-269,270,287/00-05-16 | NCV | EFW System Single Failure Vulnerability and Inadequate 10 CFR 50.59 Safety Evaluation (Section 4OA6.2) |
| 50-269,270,287/00-05-17 | NCV | Inadequate EFW System Seismic Boundary (Section 4OA6.2) |
| 50-269,270,287/00-05-18 | NCV | Inadequate 10 CFR 50.59 Safety Evaluation for UFSAR Change That Reduced EFW System Design Criteria (Section 4OA6.2) |

Previous Items Closed

| | | |
|---|---|---|
| 50-269,270/99-06-05 | URI | Review of Drip Pan Leakage in the Reactor Coolant Pump Oil Collection Systems (Section 1R05.3) |
| 50-269,270,287/99-13-01 | EEI | Past EFW System Design Was Not Functional for a Main Feedwater Line Break (Section 4OA6.2) |
| 50-269,270,287/99-13-02 | EEI | Inadequate Corrective Action and |

| | | |
|---|---|---|
| | | Reporting for Past EFW System Design That Was Not Functional for a Main Feedwater Line Break (Section 4OA6.2) |
| 50-269,270,287/99-13-03 | EEI | Insufficient Water Sources for EFW System (Section 4OA6.2) |
| 50-269,270,287/99-13-04 | EEI | EFW System Single Failure Vulnerability (Section 4OA6.2) |
| 50-269,270,287/99-13-05 | EEI | Inadequate EFW System Seismic Boundary (Section 4OA6.2) |
| 50-269,270,287/99-13-06 | EEI | Inadequate Safety Evaluation for EFW System Modification to Automatically Close Valve C-187 and Protect EFW Pumps' Suction Source (Section 4OA6.2) |
| 50-269,270,287/99-13-07 | EEI | Inadequate Safety Evaluation for UFSAR Change That Reduced EFW System Design Criteria (Section 4OA6.2) |

## LIST OF ACRONYMS USED

AC - Alternating Current
AHU - Air Handling Unit
ALARA- As Low As Reasonably Achievable
ASME - American Society of Mechanical Engineers
BS - Building Spray
BWST - Borated Water Storage Tank
CFR - Code of Federal Regulations
DC - Direct Current
ECCS - Emergency Core Cooling System
ERO - Emergency Response Organization
GL - Generic Letter
HPI - High Pressure Injection
IP - Inspection Procedure
ISFSI - Independent Spent Fuel Storage Installation
KHU - Keowee Hydro Unit
KV - Kilovolt
LCO - Limiting Conditions for Operation
LER - Licensee Event Report
LPI - Low Pressure Injection
LPSW - Low Pressure Service Water
NI - Nuclear Instruments
NCV - Non-Cited Violation
NRC - Nuclear Regulatory Commission
NRR - Nuclear Reactor Regulation

| | | |
|---|---|---|
| NSD | - | Nuclear System Directive |
| PI | - | Performance Indicator |
| PIP | - | Problem Identification Process |
| PMT | - | Post Maintenance Testing |
| psig | - | pounds per square inch gauge |
| RCMU | - | Reactor Coolant Make-Up |
| RCP | - | Reactor Coolant Pump |
| RCS | - | Reactor Coolant System |
| SDP | - | Significance Determination Process |
| SLC | - | Selected Licensee Commitments |
| SR | - | Surveillance Requirement |
| SSC | - | Structure, System and/or Component |
| SSF | - | Standby Shutdown Facility |
| TIA | - | Task Interface Agreement |
| TS | - | Technical Specification |
| UFSAR | - | Updated Final Safety Analysis Report |
| URI | - | Unresolved Item |
| V | - | Volt |

# NRC's REVISED REACTOR OVERSIGHT PROCESS

The federal Nuclear Regulatory Commission (NRC) recently revamped its inspection, assessment, and enforcement programs for commercial nuclear power plants. The new process takes into account improvements in the performance of the nuclear industry over the past 25 years and improved approaches of inspecting and assessing safety performance at NRC licensed plants.

The new process monitors licensee performance in three broad areas (called strategic performance areas): reactor safety (avoiding accidents and reducing the consequences of accidents if they occur), radiation safety (protecting plant employees and the public during routine operations), and safeguards (protecting the plant against sabotage or other security threats). The process focuses on licensee performance within each of seven cornerstones of safety in the three areas:

**Reactor Safety**

- Initiating Events
- Mitigating Systems
- Barrier Integrity
- Emergency Preparedness

**Radiation Safety**

- Occupational
- Public

**Safeguards**

- Physical Protection

To monitor these seven cornerstones of safety, the NRC uses two processes that generate information about the safety significance of plant operations: inspections and performance indicators. Inspection findings will be evaluated according to their potential significance for safety, using the Significance Determination Process, and assigned colors of GREEN, WHITE, YELLOW or RED. GREEN findings are indicative of issues that, while they may not be desirable, represent very low safety significance. WHITE findings indicate issues that are of low to moderate safety significance. YELLOW findings are issues that are of substantial safety significance. RED findings represent issues that are of high safety significance with a significant reduction in safety margin.

Performance indicator data will be compared to established criteria for measuring licensee performance in terms of potential safety. Based on prescribed thresholds, the indicators will be classified by color representing varying levels of performance and incremental degradation in safety: GREEN, WHITE, YELLOW, and RED. GREEN indicators represent performance at a level requiring no additional NRC oversight beyond the baseline inspections. WHITE corresponds to performance that may result in increased NRC oversight. YELLOW represents performance that minimally reduces safety margin and requires even more NRC oversight. And RED indicates performance that represents a significant reduction in safety margin but still provides adequate protection to public health and safety.

The assessment process integrates performance indicators and inspection so the agency can reach objective conclusions regarding overall plant performance. The agency will use an Action Matrix to determine in a systematic, predictable manner which regulatory actions should be taken based on a licensee's performance. The NRC's actions in response to the significance (as represented by the color) of issues will be the same for performance indicators as for inspection findings. As a licensee's safety performance degrades, the NRC will take more and increasingly significant action, which can include shutting down a plant, as described in the Action Matrix.

More information can be found at: http://www.nrc.gov/NRR/OVERSIGHT/index.html.

The exercise begins with Oconee Unit 1 operating at 100% power (beginning of core life ≈ 4 Effective Full Power Days (EFPDs)), Unit 2 shutdown for a refueling outage with core unloading completed, and Unit 3 at 100% power (middle of core life - 254 EFPDs). The site's Standby Shutdown Facility (SSF) is out of service for piping modifications, diesel generator maintenance, and breaker maintenance. Keowee Hydro Unit 1 and 2 are available as emergency power supplies. All three combustion turbines at Lee Steam Station are also available to supply emergency power.

The weather forecast for Monday evening, June 12th, calls for severe thunderstorms with winds from the West (≈ 270°) with a wind speed of 20 - 30 mph. A low temperature of 65 °F is expected during the night.

The weather forecast for Tuesday, June 13th, calls for winds from the West (≈ 270°) with a wind speed of 5-10 mph. A low temperature of 67 °F is expected with a high temperature of 86 °F. A 75% chance of late evening thunderstorms is expected.

At 1900 Unit 1 is operating with no major problems. A *Technical Specification Limiting Condition For Operation* is in effect due to the SSF being out of service for maintenance, with the SSF due back in service by 06/18/00. Maintenance personnel are in the Unit 1&2 Spent Fuel Pool (SFP) moving fuel that has been unloaded from Unit 2 as part of refueling activities.

At 1915 fuel assembly NJ087J fails at the top while being moved in the Unit 1&2 SFP. The assembly drops in the mast and two fuel pins are damaged. Personnel on the SFP Bridge observe bubbling in the pool as fuel gap gases are released. The portable radiation monitor on the fuel bridge alarms and maintenance personnel evacuate the Unit 1&2 SFP notifying Unit 1 Control Room personnel of conditions/observations in the SFP. Area Radiation Monitor 1RIA-6 (1&2 SFP) and Process Radiation Monitor 1RIA-41 (SFP Building Gas) reach their respective ***High*** Alarm setpoints of 25 mR/hr and 2.94 $E^3$ ccpm. At this time, the air handling unit supplying inlet air to the Unit 1&2 SFP also fails. 1RIA-6 continues increasing and reaches a maximum reading of 3.8 $E^4$ mR/hr in five minutes. 1RIA-41 continues increasing over the next six minutes until it reaches it's maximum range value of 1.0 $E^7$ ccpm. Process Radiation Monitor 1RIA-45 (Unit Vent Gas - Normal) begins to increase above it's background reading. A monitored release, Below Normal Operating Limits, is in progress at this time; however, no activity is detected at the site or offsite.

The Control Room Operators respond to the radiation monitor alarm indications and inform the Control Room Senior Reactor Operator (SRO) of the current plant conditions and monitor readings. The Control Room SRO notifies the Operations Shift Manager (OSM). A Non Licensed Operator (NLO) is directed to line up the Spent Fuel Ventilation Filters; however, both SFP Filter Ventilation fans fail - F1 due to fan problems and F2 due to a breaker fault. Dose rates in the area of the SFP prevent the NLO from further troubleshooting of this problem.

After notification from the Control Room SRO, the OSM reviews the Emergency Classification procedure and declares an **Alert** at approximately 1930 based on ***Major Damage To Irradiated Fuel Or*** *Loss Of Water Level That Has Or Will Result In The Uncovering Of Irradiated Fuel Outside The Reactor Vessel - Valid RIA 3, 6, 41, OR 49* ***HIGH*** *Alarm.*. Procedure actions are initiated to: notify offsite agencies (SC State, Oconee County, Pickens County, and NRC); activate ERDS; activate the site's Emergency Response Organization (ERO); and, recall emergency response personnel to the site. Site Assembly is initiated and site personnel are warned of the radiation hazard near the SFP. The SC State Warning Point, Oconee County LEC, and Pickens County LEC are notified of the Alert at 1945 (or within 15 minutes after the declaration).

Site Assembly is completed by 2000 (or within 30 minutes after initiation). Duty ERO personnel are enroute to the site and EOF. Staffing of the TSC and OSC is being provided by on-shift resources. At approximately 2045 (within 75 minutes of the Alert declaration), after the TSC Emergency Coordinator has completed turnover with the OSM, the TSC is *Activated*. The TSC is now responsible for Emergency Classification, Offsite Communications, and Protective Action Recommendations. Site personnel are monitoring plant conditions and implementing appropriate response actions. Field Monitoring Teams are surveying the site and downwind environs to determine the impact of this event. No increase in activity is detected.

Minimum staffing at the EOF is also completed at 2045 and the EOF is declared *Operational* at this time.

If not provided earlier, Follow-Up Notifications are provided to the SC State EOC, Oconee County EOC, and Pickens County EOC at 2045 (or at least 1 hour after the initial emergency notification). The site remains in an Alert classification.

The EOF completes turnover with the TSC and is *Activated* at approximately 2115. The EOF is now responsible for Emergency Classification, Offsite Communications, and Protective Action Recommendations. The EOF Director notifies the State Emergency Preparedness Director, Oconee County Emergency Preparedness Director, and Pickens County Emergency Preparedness Director that the EOF is activated and provides additional information concerning current plant conditions.

At 2130, objectives related to after hours activation of the ERO have been adequately demonstrated and the Exercise is *Suspended*. The ERO is instructed to return back to their respective Emergency Response Facility by 0730 on June 13th. A Follow-Up Notification is provided to the SC State EOC, Oconee County EOC, and Pickens County EOC. For the purposes of this exercise, offsite agencies request that the next Follow-Up Notification be provided by 0845 on June 13th.

At 0730 on June 13th, ERO personnel report to their respective facilities and are briefed on current plant conditions. Overnight, plant personnel were able to return one of the Spent Fuel Filtered Ventilation Fans to service. This has reduced the area radiation readings in the SFP, enabling OSC personnel to enter the room to assess the condition of the damaged fuel element. Elevated dose rates have been observed in the Purge Rooms and SFP Cooler and Filter rooms. No releases are occurring at this time.

At approximately 0800, the exercise resumes. Unit 1 remains at 100% Power. Alert conditions still exist and emergency response personnel are implementing appropriate response actions. An OSC team enters the SFP to assess the condition of the damaged fuel element. At 0815, one of the OSC team members in the SFP slips and falls, resulting in a medical injury. Due to the location of the fall, the individual is radioactively contaminated. At 0820, the OSC receives a call on the site's emergency response line concerning this event. The site's medical emergency response team (MERT) is activated and dispatched to the SFP. MERT identifies the need for an ambulance to transport the individual for further treatment (this activity will simulated; ie, Oconee EMS will not be notified to transport the injured person to the hospital).

At 0830, 1B Low Pressure Service Water (LPSW) Pump fails due to a breaker problem. This loss requires entry into a *Selected Licensee Commitment Action Statement*. Operations and OSC personnel initiate actions to recover the pump. The pump is restored to service by 0915.

At 0845 a Follow-Up Notification is provided to the SC State EOC, Oconee County EOC, and Pickens County EOC.

At 0900, high vibrations are indicated on Unit 1's 1B2 Reactor Coolant Pump (RCP). *Sustained Low Magnitude Noise* can be heard on the Loose Parts Monitor. Control Room personnel initiate a power reduction to less than 70% power. Low Oil Level alarms are received in the control room. Some fuel damage results from RCP debris; however, it is less than 1% at this time.

Once Unit 1 is < 70% power, the 1B2 RCP is secured. TSC and OSC personnel are evaluating the Loose Parts Monitor noise.

At 0925, a steam generator tube rupture (SGTR) occurs on 1B Steam Generator. This results in an RCS leak of ≈ 200-210 gallons per minute (gpm). Control Room operators initiate applicable procedures and initiate a shutdown of unit 1. Plant conditions require the site to remain at an **Alert** classification due to a *Potential Loss of the RCS Barrier* resulting from the SGTR.

At 0930, a Turbine Trip occurs that results in a Unit 1Reactor Trip (shutdown). The Main Steam Relief Valves (MSRVs) lift in response to the Reactor Trip; however, two MSRVs on the 1B Main Steam Line remain open and will not reseat. This results in a *Loss of the Containment Barrier* and a radiological release pathway. Conditions exist at this time for a **Site Area Emergency** classification due to the failed MSRVs (*Loss of the Containment Barrier)* and the SGTR (*Potential Loss of the RCS Barrier)*.

At 0935, the EOF Director declares a **Site Area Emergency** based on *Loss of the Containment Barrier and the Potential Loss of the RCS Barrier.* No Protective Action Recommendations are required at this time. Notification of the **Site Area Emergency** classification is provided to the SC State EOC, Oconee County EOC, and Pickens County EOC by 0950 (or within 15 minutes after the event is classified). Oconee County and Pickens County coordinate activation of the Alert and Notification System (EAS and Sirens) with SC State. EAS and Sirens are activated at 1005 (or within 15 minutes of the decision by State and County Emergency Preparedness Directors to activate the Alert and Notification System).

At 1015, fuel failures increase to approximately 1%. This increase results in an increase in rad levels as indicated on various area radiation monitors. Due to plant conditions, the TSC Emergency Coordinator may evacuate non-essential personnel. RP personnel prepare an evacuation plan that sends personnel to Keowee Elementary School due to the fact that a radiological release is in progress. With the radiological release in progress, vehicles located in the parking lots East of the plant would be unavailable for use. The OSC would arrange for transportation of affected personnel. The TSC Offsite Communicator (or EOF State/County Communicator) should request Oconee County to provide assistance as needed.

From 0930 to 1045, plant personnel initiate actions to minimize the release from the ruptured steam generator. OSC personnel attempt to close the MSRVs without success. The offsite radiological release continues.

At 1045, RCP seals begin to leak on the damaged 1B2 RCP. A small RCS leak of approximately 6-8 gpm begins into containment. Fuel failures increase as indicated by an increase in plant area radiation monitors. High Radiation Containment Monitors, 1RIA-57 and 1RIA-58 indicate > 1.0 R/Hr in containment. The site remains in a **Site Area Emergency** classification.

Follow-Up Notifications are provided to the SC State EOC, Oconee County EOC, and Pickens County EOC at approximately 1050 (or at least 1 hour after the initial notification).

At 1100, 1RIA-57 indicates > 80 R/hr and 1RIA-58 indicates > 40 R/hr. Conditions exist at this time for a **General Emergency** classification.

After reviewing the Emergency Classification procedure, the EOF Director declares a **General Emergency** at 1115 based on a *Loss of any two barriers (Containment and Fuel Clad) and Potential Loss of the third barrier*. A Protective Action Recommendation to evacuate a two mile radius, evacuate five miles down wind, and shelter the remaining sectors is provided by to SC State by the EOF Director. The SC State EOC, Oconee County EOC, and Pickens County EOC are notified of the **General Emergency** classification and Protective Action Recommendations at 1130 (or within 15 minutes after the event declaration). After reviewing the site's Protective Action Recommendations and current plant conditions, SC State along with Oconee and Pickens Counties determine the Protective Action Recommendations that will be issued. Within 15 minutes of this determination state and county personnel begin to implement the agreed on Protective Actions. The Alert and Notification System is activated (simulated at this time; however, actual activation may occur if required due to system problems during the Site Area Emergency).

Site Evacuation of non-essential personnel is initiated by 1130 if it was not performed earlier. RP personnel prepare an evacuation plan that sends personnel to Keowee Elementary School due to the fact that a radiological release is in progress. With the radiological release in progress, vehicles located in the parking lots East of the plant would be unavailable for use. The OSC would arrange for transportation of affected personnel.

TSC personnel may direct steaming the isolated 1B steam generator to the condenser to minimize the consequences of the offsite release; however, regulatory action would be required (implementation of the provisions of 10CFR50.54(x)). This action would route the majority of the steam being released to the condenser and provide OSC personnel with an opportunity to close the stuck MSRVs. Once the MSRVs are closed, the unmonitored radiological release would be stopped.

The exercise is terminated by 1400 once the state and counties complete demonstration of applicable objectives.