UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
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ATLANTA, GEORGIA 30303-8931

July 10, 2000

Duke Energy Corporation
ATTN: Mr. G. R. Peterson
Site Vice President
Catawba Nuclear Station
4800 Concord Road
York, SC 29745

SUBJECT: CATAWBA NUCLEAR STATION - NRC INSPECTION REPORT 50-413/00-03 AND 50-414/00-03

Dear Mr. Peterson :

On June 24, 2000, the NRC completed an inspection at your Catawba reactor facility. The enclosed report presents the results of that inspection. The results of this inspection were discussed on June 27, 2000, with you and members of your staff.

The inspection was 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 inspection consisted of a selective examination of procedures and representative records, observations of activities, and interviews with personnel.

Based on the results of this inspection, seven issues of very low safety significance (Green) were identified. 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 seven issues, four were determined to involve violations of NRC requirements, but because of their very low safety significance the violations are not cited. 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 Catawba 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/ADAMS/index.html (the Public Electronic Reading Room).

Sincerely,

/RA/

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

Docket No.: 50-413, 50-414
License No.: NPF-35, NPF-52

Enclosure: NRC Inspection Report
w/Attached NRC's Revised Reactor
Oversight Process

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U. S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket No:	50-413, 50-414
License No:	NPF-35, NPF-52
Report No:	50-413/00-03, 50-414/00-03
Licensee:	Duke Energy Corporation
Facility:	Catawba Nuclear Station, Units 1 and 2
Location:	422 South Church Street Charlotte, NC 28242
Dates:	April 2 - June 24, 2000
Inspectors:	D. Roberts, Senior Resident Inspector R. Franovich, Resident Inspector M. Giles, Resident Inspector D. Thompson, Physical Security Specialist (Sections 3PP1, 3PP2) F. Wright, Senior Radiation Specialist (Sections 2OS2, 2PS3)
Approved by:	C. Ogle, Chief Reactor Projects Branch 1 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

Catawba Nuclear Station, Units 1 and 2
NRC Inspection Report 50-413/00-03, 50-414/00-03

The report covers a 12-week period of resident inspection, as well as announced inspections by a regional radiation specialist and a security specialist. 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: Mitigating Systems

- Green. The licensee failed to properly classify a maintenace rule functional failure of the Unit 2 A steam generator power operated relief valve (2SV-19) when it failed to open on April 15, 2000. The licensee incorrectly assumed that the valve's failure was not a functional failure because other redundant valves were available at the time. This issue was determined to have very low safety significance because the licensee's error did not result in additional equipment unavailability (Section 1R12.1).

- Green. The licensee failed to include in its maintenance rule scope an accident mitigating function for a control room alarm associated with emergency core cooling system post-accident leak detection capability. The alarm was tied to residual heat removal and containment spray pump room sump levels and was identified in 1998 as a mitigating function, as described in the Catawba Updated Final Safety Analysis Report. As a result, two functional failures were not properly classified in February 2000. This issue was characterized as a non-cited violation of 10 CFR 50.65 (b)(2) and was determined to have very low safety significance because the licensee's scoping and functional failure determination errors did not directly result in additional unavailability of the alarm function (Section 1R12.2).

- Green. Steam generator power operated relief valve 2SV-19 failed to open on April 15, 2000, due to mispostioned nitrogen pressure regulators, which are required to function during a design basis event involving the loss of normally available instrument air. The licensee determined the mispositioned regulators to be a human performance issue, but were not able to pinpoint when the actual mispositioning took place. This issue was determined to have very low safety significance due to the availability of other steam generator power operated relief valves and diverse means of cooling the secondary plant (Section 1R22.2).

- Green. Residual heat removal and containment spray pump room sump level alarm function was lost for several months up to February 2000 due to inadequate maintenance procedures associated with sump level switch calibrations. This issue was characterized as a non-cited violation of Technical Specification 5.4.1 and was determined to be of very low safety significance due to the availability of other emergency core cooling system leak detection methods (Section 4OA3.2).

Cornerstone: Barrier Integrity

- Green. The licensee did not properly evaluate plant risk associated with emergent work for the Unit 2 hydrogen ignition system on April 27, 2000. As a result, the unit was in an unevaluated increased risk condition while planned work associated with the containment spray system was ongoing. This condition was allowed by Technical Specifications and plant procedures, but plant procedures required that a written contingency plan be developed prior to the work commencing, which was not done. This issue was of very low safety significance due to the availability of diverse and redundant systems designed to accomplish the hydrogen mitigation and containment pressure control functions (Section 1R13).

Cornerstones: Occupational and Public Radiation Safety

- Green. A non-cited violation was identified for the failure to comply with the requirements of 10 CFR 20.1802. Specifically, on April 7, 2000, the licensee failed to prevent the release of radioactive byproduct material (e.g., a radioactive particle on a contract employee's lanyard) from the radiological control area and plant site. Based on the activity of the particle and the resulting occupational dose assessment for the affected contract employee, this finding was determined to be of very low significance (Sections OS2, 2PS3).

Cornerstone: Physical Protection

- Green. A non-cited violation of the Physical Security Plan was identified for the licensee's failure to secure two vital area openings exceeding 96 square inches in February 1999. This issue was determined to have very little significance, given the non-predictable basis of the failures and the fact that there was no evidence that the vulnerabilities had been exploited (Section 3PP2).

Report Details

Summary of Plant Status:

Unit 1 was at 100 percent power throughout the inspection period, except for a brief period between May 12 and May 13, 2000, when reactor power was reduced to 88 percent to facilitate main turbine valve testing. The unit was returned to 100 percent power following successful completion of the testing.

Unit 2 began the period shutdown for the End-of-Cycle 10 refueling outage. After refueling, the reactor was taken critical on April 8 and the unit reached 100 percent power on April 11, 2000. Between April 27-30, 2000, the unit was at reduced power (18 percent) to facilitate repairs to the hydrogen ignition system in containment. On June 5, 2000, the unit experienced a turbine/reactor trip from 100 percent power following a feedwater system transient in which the 2B main feedwater pump turbine experienced a speed control failure. This was caused by excessive rain and a faulty turbine building roof drainage system, which allowed water to enter the 2B pump turbine control power cabinet and cause electronic card failures. Following repairs, the unit was restarted on June 7, 2000, and reached 100 percent power on June 10, 2000. On June 20, 2000, the B main feedwater pump again experienced turbine speed control problems and operators reduced power to 65 percent to allow the pump to be removed from service. On June 23, 2000, pump turbine speed control system repairs and testing were completed and the unit was returned to full power.

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

1R04 Equipment Alignment

a. Inspection Scope

The inspectors performed partial walkdowns of the Unit 1 vital battery system, the 2A emergency diesel generator and support systems, and the A train of the control room ventilation system to verify their availability while redundant system equipment was inoperable for various reasons. In addition, the inspectors conducted a full system walkdown of the Unit 2 component cooling water system to verify that components were properly operating, labeled, and in good working condition. The full system walkdown included a review of outstanding work requests and corrective action program documents to verify that the licensee was properly identifying and correcting system problems.

b. Issues and Findings

No findings were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors toured six 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, probabilistic risk assessment (PRA)-based sensitivity studies for fire-related core damage accident sequences, and summary statements related to the licensee's 1992 Initial Plant Examination for External Events submittal to the NRC. Areas toured this quarter included various elevations of the Unit 1 turbine building, Unit 1 and 2 service building, and the Unit 1 and 2 auxiliary building.

In addition, the inspectors observed an announced fire brigade training drill conducted on May 30, 2000, which simulated a fire in the Unit 2 auxiliary feedwater pump room.

b. Issues and Findings

No findings were identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

The inspectors observed a control room simulator training scenario on May 9, 2000, to assess licensed reactor operator and senior reactor operator performance. The training scenario involved a seismic event and subsequent plant shutdown. The inspectors focused on the performance of the operators in implementing the emergency plan, plant procedures, and Technical Specifications (TS). 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

.1 Review of Various Equipment Issues

a. Inspection Scope

The inspectors reviewed the licensee's implementation of the maintenance rule (10 CFR 50.65) with respect to the five equipment issues identified in the following Problem Investigation Process reports (PIPs) and TS Action Item Log (TSAIL) entries:

PIP C-98-04282	Unit 1 nuclear service water system a(1) classification due to component cooling water heat exchanger fouling
PIP C-00-02068	Failure of Unit 2 'A' steam generator (S/G) power-operated relief valve (PORV) to stroke open with backup nitrogen system
PIP C-00-02788	Failure of containment isolation valve 2NM-220B
PIP C-00-02248	Functional failure determination for the April 2000 hydrogen ignitor system failure

Various TSAIL entries	Unavailability of the hydrogen ignitor system during routine testing

b. Issues and Findings

The inspectors noted that PIP C-00-02068 described the failure of valve 2SV-19, the Unit 2 ‘A’ S/G PORV, to stroke open during a surveillance test on April 15, 2000, in which the normal instrument air supply to the valve was isolated and the backup safety-related nitrogen supply was relied upon. The S/G PORVs are included in the scope of the maintenance rule as part of the “Main Steam Relief to Atmosphere” system. Their primary accident function is to provide for manual control of secondary plant cooldown following a steam generator tube rupture (SGTR) event such that containment pressures are maintained within assumed limits. This function is defined in the licensee’s Maintenance Rule Structures, Systems, and Components (SSC) Summary Sheets, and is scoped as a non-risk significant and standby function. During a design basis SGTR event, the safety-related nitrogen backup supply is relied upon (assuming a loss of normal instrument air supply) to control the valves manually (and remotely) from the control room. Technical Specification Surveillance Requirement 3.7.4.2 requires that each valve be subject to one complete stroke with nitrogen every 18 months. The limiting condition for operation (LCO) of TS 3.7.4 requires, with one PORV line inoperable, that the licensee restore the inoperable PORV to operable status within 7 days. The LCO basis states that four PORV lines are required to be operable to ensure that at least two are available to conduct a unit cooldown following a SGTR. This is because one of the four is assumed to be lost due to the associated ruptured S/G, and two of the remaining three are lost due to a previously analyzed single active failure. One of those two is credited for being locally operated along with the remaining unaffected PORV, which is controlled manually from the control room to mitigate the accident.

The licensee’s investigation into the failure of 2SV-19 found that the valve would not open from the control room due to both of its nitrogen pressure regulators being improperly set too low. This is further discussed in Section 1R22.2 of this inspection report.

The licensee’s initial maintenance rule functional failure determination documented in PIP C-00-02068 stated that the failure of valve 2SV-19 to open was not a functional failure because at least two other PORVs were available to satisfy the function as defined in the scoping summary sheet. Based on that conclusion, no maintenance preventable functional failure (MPFF) determination was performed. The inspectors noted that this conclusion did not take into account the fact that the valve had failed a function for which it was scoped into the rule. The licensee’s conclusion also did not take into account statements in the TS Bases explaining why all four PORVs were required to be operable. The inspectors discussed this aspect with cognizant licensee personnel who reiterated their position by revising the PIP functional failure determination to state that the failure of 2SV-19 could be considered the single failure referenced in the TS Bases when evaluating whether or not its failure on April 15, 2000, constituted a maintenance rule functional failure. The licensee added that as long as three other PORVs were available, the function was met. The inspectors concluded that the licensee’s functional failure determination was inappropriate and that the failure of 2SV-19 did constitute a functional failure.

Toward the end of the inspection period, the licensee determined that their functional failure determination was incorrect and that this may have been due to the system engineer being misled by the function description in the SSC Summary Sheet. The licensee revised PIP C-00-02068 to document the April 15, 2000, incident as a MPFF and included a corrective action to address the initial improper determination. Although the inspectors have noted previous licensee performance problems in the area of maintenance rule implementation, the inspectors determined that this error did not result in any additional equipment failures. Therefore, this issue was of very low safety significance and was screened as green in Phase 1 of the Significance Determination Process (SDP). Because this missed MPFF classification did not result in the 10CFR 50.65 a(2) demonstration becoming invalid, a violation of 10 CFR 50.65 did not occur.

.2 Control Room Computer Alarm Unavailable due to Inappropriate Maintenance

a. Inspection Scope

The inspectors reviewed PIPs C-00-00592 and -00685 associated with the unavailability of a computer alarm associated with the Unit 1 and 2 residual heat removal (ND) and containment spray (NS) pump room sump level instruments. The unavailability of this alarm is also described in Licensee Event Report (LER) 50-413/2000-002, which is discussed in Section 4OA3.2. The inspectors also reviewed Sections 5 and 6 of the Catawba Updated Final Safety Analysis Report (UFSAR), which described this mitigating feature, and Engineering Directives Manual (EDM) 210, Rev. 11, Engineering Responsibilities for the Maintenance Rule. The inspectors reviewed the licensee's implementation of the maintenance rule with respect to this unavailability.

b. Issues and Findings

Background

The high and high-high level alarms associated with the ND/NS pump area sumps are described in the UFSAR as a means for operators to determine that an ECCS system leak has occurred outside containment following a design basis loss of coolant accident (LOCA). The inspectors identified a non-cited violation (NCV) for failure to scope the ND/NS sump alarm feature in the maintenance rule. A detailed description of the alarm's design basis function and the maintenance errors that lead to the function being disabled for several months in 1999 and 2000 are discussed in Section 4OA3.2.

Problem Assessment

The ND/NS pump area sump level control room computer alarm was unavailable from August 30, 1999, to February 10, 2000, and again for four hours on February 16, 2000, due to inadequate controls and maintenance procedures for performing calibrations on associated level switches. The inspector reviewed the licensee's maintenance rule evaluations for these incidents and found that they had determined the two losses of this alarm not to be functional failures. The licensee based this determination on the fact that the level alarm was not included in the scope of the maintenance rule for the design basis accident mitigating function described in the UFSAR.

The inspectors noted that this alarm feature is used by control room operators to confirm excessive leakage from ECCS components, particularly from a seal failure of the ND or NS pumps, following a design basis LOCA. The Catawba UFSAR states that once the sump alarms confirm excessive leakage, operators determine which train is faulted by measuring flow at the discharge of each ECCS pump, and subsequently isolate the faulted train. The plant computer alarm function associated with high-high ND/NS sump level changed in October 1998 when the licensee began relying on it to satisfy the leak detection function until a permanent plant modification to install a safety injection signal interlock and a dedicated control room annunciator could be completed in the fall of 2000. The inspectors determined that maintenance rule implementing procedure EDM-210, Section 210.8.3.2, required that engineers complete an accident mitigation rescoping analysis based on a review of the UFSAR when a SSC function has changed. The inspectors concluded that the alarm feature should have been scoped in the maintenance rule in 1998 for the accident mitigating function described in the UFSAR and that the two incidents identified in February 2000 constituted either functional failures or unavailability, or both. The inspector discussed this issue with licensee personnel who indicated that they were in the process of performing a maintenance rule scoping analysis of this function, but were waiting for the permanent modification to be completed.

Although the inspectors have noted previous licensee performance problems in the area of maintenance rule implementation, the inspectors determined that this error did not contribute to any additional equipment failures. Thus, the failure to include the sump level alarm function in the maintenance rule scope and monitor the effectiveness of preventive maintenance (i.e., properly classify two functional failures or functional unavailability) was of very low safety significance and was screened in Phase 1 of the SDP as “green.”

10 CFR 50.65 (a)(1), requires, in part, that the licensee shall monitor the performance or condition of structures, systems, or components (SSCs) within the scope of the rule as defined by 10 CFR 50.65 (b), against licensee-established goals, in a manner sufficient to provide reasonable assurance that such structures, systems, and components, are capable of fulfilling their intended functions. 10 CFR 50.65 (a)(2) states, in part, that monitoring as specified in 10 CFR 50.65 (a)(1) is not required where it has been demonstrated that the performance or condition of an SSC is being effectively controlled through the performance of appropriate preventive maintenance, such that the SSC remains capable of performing its intended function. 10 CFR 50.65 (b)(2) states that nonsafety-related SSCs that are relied upon to mitigate accidents or transients or are used in plant emergency operating procedures are to be included in the scope of the monitoring program specified in paragraph (a)(1). As described above, the licensee failed to scope the ND/NS sump level alarm feature in the maintenance rule, and did not identify two functional failures of this component in February 2000. This is considered a violation of 10 CFR 50.65 (b)(2). This violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. It is identified as NCV 50-413,414/00-03-01: Failure to Scope an Accident Mitigating Function Associated with ECCS Leak

Detection in the Maintenance Rule. This violation is in the licensee's corrective action program as PIP C-00-00592.

As a side item, the inspectors noted that the alarm was not referenced in emergency operating procedures, and the computer point alarm response procedure did not include any of the accident mitigating actions described in the UFSAR. This item was communicated to plant personnel who indicated that procedural enhancements would be considered when permanent modifications associated with this alarm function are completed after the Fall 2000 Unit 1 refueling outage.

1R13 Maintenance Risk Assessment and Emergent Work Evaluation

a. Inspection Scope

The inspectors reviewed the licensee's assessments of the risk impacts of removing from service those components associated with the six emergent and planned work items listed below, focusing primarily on activities determined to be risk-significant within the maintenance rule. The inspectors evaluated: (1) overall impact to PRA based on the SSC unavailability; and (2) actual SSC unavailability date as compared to scheduled unavailability date with PRA implications.

Component or System	Reason for Removal from Service
2B Emergency Diesel Generator (EDG)	Test failure; governor adjustment
Unit 2 Train B Hydrogen Ignition	Test failure; inadequate glow plug current
1A EDG	Test failure; incorrectly set digital reference unit (DRU) potentiometer
Unit 2 turbine-driven auxiliary feedwater pump	Trip and throttle valve actuator stem failure
Vital bus 2EBA	Planned maintenance
2B Centrifugal Charging Pump	Planned maintenance

b. Issues and Findings

On April 27, 2000, the inspectors asked whether or not work control personnel had factored ongoing maintenance of the Unit 2 B train hydrogen mitigation (EHM) system into its daily risk profile for online work. The B train of the hydrogen ignitor portion of the system had failed a surveillance test the day before, which rendered it inoperable and unavailable, and preparations were being made to repair individual glow plugs associated with the train. The inspectors noted that the B train of the NS system had also been rendered inoperable on April 27 due to planned maintenance and testing of its associated pump and heat exchanger. Work control personnel stated that they were aware of the B train EHM system inoperability, but had determined the system to be available for maintenance rule purposes. When the inspectors pointed out the that the train was unavailable due to the number of ignitors involved and the nature of the ongoing maintenance and testing, the licensee agreed and reevaluated the risk; this time correctly factoring in the B EHM train unavailability. Because both the EHM and NS systems were designed to protect the reactor containment barrier, and because both were simultaneously degraded due to maintenance, the licensee determined that Unit 2 had been in an increased risk condition, per its online risk assessment matrix (ORAM) program.

The inspectors noted from a review of Work Process Manual (WPM) 609, Revision 1, Innage Risk Assessment Utilizing ORAM-SENTINEL, that this level of increased risk was to be accompanied by a written contingency plan to restore the SSC, prior to the work commencing. The inspectors noted that these plans typically employ a defense-in-depth strategy and reference abnormal or emergency procedures for the loss of the associated function. When the risk assessment error was identified, the NS system work had already been completed and the system was in the process of being restored to standby status. However, because the licensee did not properly implement its own requirements for controlling risk, they generated PIP C-00-02265 to document the error. A subsequent investigation by the licensee determined that further training was needed for operators and work control personnel responsible for implementing the requirements of WPM 609, because of weaknesses identified in the use of the ORAM-SENTINEL program and non-conservative assumptions concerning when it is to be used.

The inspectors determined that, while the two systems involved both protect reactor containment integrity, they provide two distinct functions. The EHM system is primarily used for controlled burns of hydrogen pockets that develop in containment following a LOCA, while the NS system is used for post-LOCA long-term containment pressure control. When the inspectors discussed this with licensee personnel familiar with the probabilistic risk assessment (PRA) for Catawba, they were told that, for containment barrier protection analysis, the ORAM-SENTINEL program primarily used a deterministic approach (i.e., qualitative versus PRA assessment of risk that incorporates safety margins and accident analyses). The inspectors were also informed that, while having the NS and EHM systems simultaneously unavailable did not significantly degrade the containment protection function, there are a small number of PRA accident sequences that assume the availability of both; thus implying that there is a small potential impact on plant risk.

On April 27, 2000, other hydrogen mitigation systems (e.g., the hydrogen recombiners, and containment air return and hydrogen skimmer fans) were available during the time that the B train of hydrogen ignition was not. The A trains of both EHM and NS were also available during this time. Because of the availability of diverse and redundant means for hydrogen mitigation and containment pressure control, the inspectors determined that this issue was of very low safety significance and was screened as “green” during Phase 1 of the SDP.

Because the condition identified on April 27, 2000, was not prohibited by TS, did not result in the plant being outside of its design basis, and there are currently no NRC regulations requiring the evaluation of risk for planned maintenance, no violations of NRC requirements occurred.

1R14 Personnel Performance During Non-routine Plant Evolutions

a. Inspection Scope

The inspectors observed or reviewed licensee performance during non-routine plant evolutions, including: a feedwater pump transient that resulted in a Unit 2 reactor trip on June 5, 2000; a Unit 2 reactor startup on June 7, 2000; and a rapid Unit 2 down power performed on June 20, 2000. These reviews were conducted to determine if operator response was appropriate and in accordance with plant procedures and training.

b. Issues and Findings

No findings were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the operability determinations (or justifications for continued operation) for the five issues described in the following PIPs:

PIP Number	Issue
C-00-01330	Unit 2 containment recirculation sump screen missing bolts; debris
C-00-02084	Effect of missing valve parts (1NV-337) on reactor coolant pumps
C-97-03621	Dose equivalent iodine limitations resulting from SGTR vulnerability
C-00-02566	1A EDG failure due to DRU not set properly
C-00-02625	Unit 1 containment recirculation sump screen issues

This review was conducted to verify that operability was properly justified, that the component or system remained available, and that no unrecognized increase in risk occurred.

b. Issues and Findings

No findings were identified.

1R16 Operator Workarounds

a. Inspection Scope

The inspectors reviewed the list of operator workarounds in place during the week of May 22, 2000, to assess individual workarounds and determine their cumulative impact on plant risk. During this review, no individual workarounds were determined to be risk significant, but those that were in place were still evaluated for their cumulative risk impact.

b. Issues and Findings

No findings were identified.

1R19 Post-Maintenance Testing

a. Inspection Scope

The inspectors observed or reviewed post-maintenance tests associated with the following six work activities:

Procedure Number	Maintenance/Test Activity
PT/2/A/4250/001C, Rev. 6	Unit 2 S/G PORV 2SV-19 stroke test following pressure regulator repair
PT/0/A/4400/022B, Rev. 53	Nuclear service water pump Train B test following planned maintenance
PT/1/A/4350/002A, Rev. 96	EDG 1A operability test following DRU failure
IP/2/A/3170/003B, Rev. 9	Quarterly current check for Train B hydrogen ignitors following replacement (Train A also reviewed)
PT/2/A/4250/03C, Rev. 61	Unit 2 auxiliary feedwater pump turbine test following trip/throttle valve actuator stem failure
PT/2/B/4250/004D, Rev. 15	Feedwater Pump 2B turbine overspeed test following speed control failure and card replacement

b. Issues and Findings

No findings were identified.

1R20 Refueling and Outage Activities

a. Inspection Scope

The inspectors observed or reviewed several activities during the last week of the Unit 2 End-of-Cycle 10 refueling outage, which was completed on April 8, 2000. These included a reactor startup, an ice condenser closeout inspection, and a containment closeout inspection. An outage-related surveillance test of the engineered safety features actuation system was also reviewed in accordance with Inspection Procedure (IP) 71111.22. The inspectors also verified that plant configuration was being controlled in accordance with the licensee’s procedures for maintaining defense-in-depth during shutdown conditions involving risk.

b. Issues and Findings

No findings were identified.

1R22 Surveillance Testing

.1 Surveillance Test Observation and Reviews

a. Inspection Scope

The inspectors reviewed the six surveillance test procedures listed below to verify that TS requirements were properly incorporated and that test acceptance criteria were properly specified. The inspectors observed actual performance of some of the tests and reviewed completed procedures to verify that acceptance criteria had been met.

Procedure Number	Title
PT/2/A/4200/09, Rev.141	Engineered Safety Features Actuation Periodic Test
PT/0/A/4200/017, Rev. 25	Standby Shutdown Facility Diesel Test
OP/1/A/6200/034, Rev. 12	Operating Procedure for Unit 1 NM (primary sample) Automation Sampling System
PT/2/A/4200/007C, Rev. 15	Standby Makeup Pump #2 Performance Test
PT/2/A/4200/007B, Rev 31	Centrifugal Charging Pump 2B Test
PT/1/A/4200/027, Rev. 40	NW (valve injection water) Valve Inservice Test

b. Issues and Findings

No findings were identified.

.2 S/G PORV 2SV-19 Failure to Open

a. Inspection Scope

During a plant status review, the inspectors learned that valve 2SV-19, Unit 2 A S/G PORV, failed to stroke open while on its nitrogen backup supply during a quarterly surveillance test. This occurred on April 15, 2000. The inspectors reviewed this test failure for its impact on plant safety and verified that the licensee properly incorporated the failure in its corrective action program.

b. Issues and Findings

The licensee immediately investigated and found that pressure regulators on the discharge of each of two nitrogen cylinders connected to the valve operator were set to zero and 20 pounds per square inch gauge (psig), versus the required 80 psig. The regulators control the pressure from each of the two redundant nitrogen cylinders to the valve. Upon discovery, the regulators were reset and the valve stroked successfully later on April 15, 2000. The licensee was unable to determine when or how the regulators were set improperly. The valve was last successfully tested on January 20, 2000. Unit 2 had been in a refueling outage from March 11, to April 8, 2000.

The inspectors reviewed the maintenance history for the valve and found no work documented between January 20, 2000, and April 15, 2000. The inspectors also reviewed security records to determine when the last entry was made, before the failure of the valve to stroke, into the Unit 2 "outside doghouse" where the valve is located. There were numerous room entries made on a daily basis during and after the Unit 2 refueling outage up to April 15, 2000, - too many entries to pinpoint a time when the pressure regulators could have been manipulated last. Based on this review, the inspectors concluded that the amount of time the valve had been inoperable was indeterminate. The licensee concluded the same and that the valve was inoperable at the time of discovery on April 15, 2000. The inspectors concluded that no TS violation occurred.

The licensee classified the regulator mispositioning as a human performance issue. This was documented in their corrective action program as PIP C-00-02068. The inspectors used the SDP to evaluate the risk significance of this issue. Consistent with Nuclear Energy Institute (NEI) document 99-02, Revision 0, Regulatory Assessment Performance Indicator Guideline, which is endorsed by the NRC and used by the licensee for reporting fault exposure hours for the safety system unavailability performance indicator (PI), the inspectors assumed that PORV 2SV-19 was unavailable for half of the period between its January 20 and April 15, 2000, surveillance tests. Because Unit 2 was in a mode where the PORV was not required to be operable for several weeks between March 11 and April 8, 2000, the period of unavailability was further reduced, but still assumed to be greater than 30 days for the SDP. During the Phase 1 screening, the inspectors determined a Phase 2 screening was required. The inspectors evaluated the unavailability using Phase 2 worksheets associated was a SGTR event, during which PORVs are relied upon to help depressurize and cool the secondary side of the plant and prevent excessive loss of primary system coolant. Based largely on the availability of the other S/G PORVs and the auxiliary feedwater system during the period of concern, this issue was determined to have little impact on SGTR mitigating capability and was of very low safety significance (green).

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation

a. Inspection Scope

The inspectors observed an emergency response organization practice drill conducted on May 17, 2000, to observe licensee performance in the area of emergency preparedness, and to assess its own critique of that performance. The majority of these observations were made in the control room simulator and the technical support center.

b. Issues and Findings

No findings were identified.

2. RADIATION SAFETY
Cornerstone: Occupational Radiation Safety

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

a. Inspection Scope:

The inspectors reviewed elements of the ALARA program and planning activities for the radiological controls implemented since the previous inspection and those of the recently completed Unit 2 refueling outage. Specific program elements reviewed included:

- The plant collective exposure history, current exposure dose trends, annual dose goals, and exposure tracking procedures;
- Source term reduction initiatives including a review of the licensee's operating and shutdown chemistry procedures and the results of those programs;
- Licensee outage reports and documentation of significant outage job evaluations and performance;
- Temporary shielding installation and removal, and schedules for scaffold erection and removal;
- Exposures for declared pregnant workers; and
- Corrective action program problem identification and resolution.

b. Issues and Findings

No findings were identified.

Cornerstone: Public Radiation Safety

2PS3 Radiological Environmental Monitoring Program and Material Control Program

a. Inspection Scope

The inspectors reviewed the events and circumstances surrounding the April 7, 2000, unconditional release of a contaminated lanyard from the licensee's radiological control area (RCA) to determine the significance of the issue and if violations of regulatory requirements had occurred.

b. Issues and Findings

An NCV was identified for the licensee's failure to comply with the requirements of 10 CFR 20.1802, in that, on April 7, 2000, the licensee failed to prevent the release of radioactive byproduct material (i.e., a radioactive particle on a contract employee's lanyard) from the radiological control area and plant site.

On April 7, 2000, the presence of low level radioactive byproduct material, 81 nanocuries (nCi) of cobalt-60 and 12 nCi of cesium-137, was initially identified on a contract worker during a routine exit whole body count analysis. As directed by radiation protection personnel, subsequent whole body counts of the employee in both street clothes and in paper clothing (without personnel items) were conducted which determined that the byproduct contamination was on the employees personal clothing or articles. However, before a health physics technician was dispatched to survey the employee's personal articles, the contract employee departed the site.

On April 10, 2000, the contract employee was contacted and arrangements were made for his personal articles to be analyzed for contamination at the Wolf Creek nuclear power station. On April 13, 2000, an analysis was performed by personnel at Wolf Creek, and on April 14, 2000, Catawba personnel were notified that the individual's clothing was clean, but a hot particle had been found embedded in the worker's lanyard. The lanyard was confiscated and shipped to the Catawba site on April 26, 2000. According to statements made by the contract employee and documented by the licensee, the contractor removed the lanyard from his body when he departed the Catawba site, and it had remained in the employee's automobile until the lanyard was delivered to the Wolf Creek power facility for analysis. This information indicated that the employee had not received a dose from the hot particle as a member of the public. From an occupational dose perspective, the licensee determined that the maximum hot particle dose for the employee was approximately 13.7 microCurie-hours (μCi-hrs). This is well below the NRC's 75 μCi-hr limit established for hot particles. The licensee also assigned a whole body dose of 1,017 mrem. The inspector determined that the licensee's dose assignment was appropriate and conservative and was included in the employee's dose record.

Based on the particle activity and the licensee's occupational dose determinations, this finding was determined to be of very low significance (green) in accordance with the Occupational Radiation Safety Significance Determination Process (SDP). Although the events described above also involved radioactive material being inappropriately released offsite, the finding is not assessed in accordance with the Public Radiation Safety SDP because the potential dose impact is to a very small localized area of the skin and is not equivalent to the risk associated with a Total Effective Dose Equivalent (TEDE) dose. This finding is, however, considered an occurrence for purposes of the Public Radiation Safety SDP. This is the first occurrence in the last two years.

Title 10 of Part 20 to the Code of Federal Regulations does not provide for the release of any radioactive materials except in liquid and gaseous releases. 10 CFR 20.1802 requires the licensee control and maintain constant surveillance of licensed material that is in a controlled or unrestricted area and that is not in storage. Licensed material means source material, special nuclear material, or byproduct material received, possessed, used, transferred or disposed of under a general or specific license issued by the Commission. Contrary to this requirement, on April 7, 2000, the licensee failed to control byproduct material on a contractor's lanyard when it was released from the RCA and the plant site. This violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. It is identified as NCV 50-413,414/00-03-02: Failure to Prevent the Release of Radioactive Byproduct Material from the Radiological Control Area and Plant Site. This violation is in the licensee's corrective action program as PIP C-0-00-1905.

3. SAFEGUARDS
Cornerstone: Physical Protection

3PP1 Access Authorization

a. Inspection Scope

The inspector interviewed representatives of licensee management and escort personnel concerning their understanding of the behavior observation portion of the personnel screening and fitness for duty (FFD) program. In interviewing these personnel, the inspector reviewed the effectiveness of their training and abilities to recognize aberrant behavioral traits.

b. Issues and Findings

No findings were identified.

3PP2 Access Control

a. Inspection Scope

The inspector observed access control activities on April 3, 4, and 6, 2000, and the equipment testing conducted on April 5, 2000. In observing the access control activities, the inspector assessed whether officers could detect contraband before it was introduced into the protected area. Additionally, the inspector assessed whether the officers were conducting access control equipment testing according to regulatory requirements.

b. Issues and Findings

While reviewing the licensee event logs to determine if the licensee had a process for controlling access to vital equipment, the inspector noted that in February 1999, the licensee discovered two breaches of vital area barriers. These were identified as an NCV.

On February 3, 1999, at approximately 10:10 a.m., a vital area patrol officer discovered that the security bars for a vital area barrier had been removed and security was not compensating for the open vital barrier. The licensee determined that although the firestop material was in place, the bars, which were installed because the opening exceeded 96 square inches, had been removed by maintenance. Security determined that the opening existed for approximately 20 hours before being discovered by security. Several factors contributed to the barrier being opened without security being established. They were: (1) maintenance and security had conferred on several penetrations during the fire prevention work and in some cases determined that the barriers were not needed because the openings did not allow access to vital areas; (2) the sign posted on the wall indicating that this was a security barrier was approximately 20 feet away; (3) the sign was not clear; and (4) during security and maintenance discussion several barriers were discussed without appropriate resolution documentation. The second event occurred on February 11, 1999, when the licensee discovered a penetration from the protected area to the vital area with an opening that exceeded 96 square inches. The licensee determined that an adequate barrier had not been established since licensing of the plant. However, access through the opening was unlikely in that the original firestop material was still bonded to the damming board as originally installed in the 1980's. The breaches were not predictable and were determined to be “green” by the SDP.

License Amendment No. 164, Paragraph E, dated April 23, 1998, states that Duke Energy Corporation shall fully implement and maintain in effect all provisions of the Commission-approved nuclear security and contingency, and guard training and qualification plans.

Paragraph 4.3 of the Physical Security Plan (PSP), Revision 12, dated April 3, 2000, requires that “vital areas of the station shall be bounded (walls, floors and ceilings) by physical barriers such that there shall be no openings of greater than ninety-six (96) square inches having a minor dimension of greater than six (6) inches, not secured by grates, doors, covers or other barriers.” Failure to adequately secure two vital area openings exceeding 96 inches is a violation of the PSP. This violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. It is identified as NCV 50-413,414/00-03-03: Failure to Secure Two Vital Area Openings Exceeding 96 Square Inches in February 1999. This violation is in the licensee’s corrective action program as PIP C-99-0045 and C-99-00445.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification

.1 Quarterly Performance Indicator Verification

a. Inspection Scope

The inspectors verified the following three Reactor Safety Performance Indicators (PIs) for accuracy:

Cornerstone	PI
Initiating Events	Unplanned Power Changes Per 7,000 Critical Hours
Mitigating Systems	Safety System Unavailability, Auxiliary Feedwater System
Barrier Integrity	Reactor Coolant System Specific Activity

To verify the PI data, the inspectors reviewed plant chemistry records, control room logs, TSAIL entries, and maintenance rule data. In accordance with IP 71111.22, the inspectors also observed portions of the chemistry surveillance procedure that collects and analyzes reactor coolant samples for determining specific activity.

b. Issues and Findings

There were no findings identified for the first two indicators listed above. However, for the Reactor Coolant System (RCS or NC) Specific Activity indicator, which monitors the integrity of the reactor fuel cladding by indicating the amount of dose-equivalent radioactive iodine that is present in the NC system, the inspectors identified a potential discrepancy with how the indicator has been calculated. The indicator is defined in NEI 99-02, Revision 0, as "the maximum monthly RCS activity in micro-Curies per gram (μCi/gm) dose equivalent Iodine-131, and expressed as a percentage of the TS limit." The inspectors noted that the licensee reported this data as a function of the TS limit (1.0 μCi/gm), even though it had imposed more restrictive limits through an operating license condition (0.46 μCi/gm) since 1997. More recently, the licensee had reduced limits on NC system specific activity even further to 0.099 μCi/gm and 0.046 μCi/gm, both of which were controlled administratively through procedures. The more restrictive limits were due to design basis issues in which single failure vulnerabilities associated with the SGTR accident analysis rendered the TS value non-conservative. The 0.046 μCi/gm limit was due to differences between actual NC system letdown flow rates and non-conservative values assumed in accident analyses. This latter restriction is related to a generic concern that affects other Westinghouse plant designs as well.

The governing NEI document contained frequently asked questions (FAQ) related to the reporting of PI data and included one asking whether or not TS limits should be used when more restrictive limits apply. The FAQ response stated, in part, that the circumstances of each situation should be identified to the NRC so that a determination can be made as to whether alternate data reporting can be used. The licensee had not consulted with the NRC prior to reporting its first quarter 2000 PI data on April 21, 2000. After the inspectors discussed this with licensee personnel, PIP C-00-02331 was generated to document the oversight. The NRC Region 2 staff and the licensee have since contacted the NRC Office of Nuclear Reactor Regulation (NRR) for resolution of this discrepancy. A clear determination of which limit should be used in the PI data had not been obtained by the close of the inspection period. Per guidance in Temporary Instruction (TI) 2515/144, "Performance Indicator Data Collecting and Reporting Process Review," the inspectors are opening an Unresolved Item (URI) pending resolution by NRR. It is identified as URI 50-413,414/00-04: Minor Discrepancy Involving the Calculation of Reactor Coolant System Specific Activity Performance Indicator.

As a precaution, the licensee recalculated the specific activity PI using the more restrictive limits and determined that, while the new denominator slightly increased the indicator from the reported values, the PI remained at a level requiring no additional NRC oversight (green).

.2 <u>PI Collecting and Reporting Verification Using TI 2515/144</u>

a. <u>Inspection Scope</u>

The inspectors reviewed the licensee's PI data collecting and reporting process to determine whether the NRC/Industry guidance was being implemented properly. The inspectors reviewed indicator definitions, calculational methods, clarifying notes, and FAQs contained in NEI 99-02 for the following six indicators:

Cornerstone	PI
Initiating Events	Unplanned Power Changes per 7,000 Critical Hours
Mitigating Systems	Safety System Unavailability, Auxiliary Feedwater System
Mitigating Systems	Safety System Functional Failures
Emergency Preparedness	Emergency Response Organization Drill Participation
Occupational Radiation Safety	Occupational Exposure Control Effectiveness
Public Radiation Safety	Protected Area Security Equipment Performance Index

b. Issues and Findings

TI 2515/144 was completed and no findings were identified.

4OA3 Event Followup

.1 Event Response

a. Inspection Scope

The inspectors responded to the control room following an uncomplicated Unit 2 turbine/reactor trip on June 5, 2000. The trip was caused by failed speed control circuitry associated with the 2B feedwater pump turbine following a heavy rainstorm and a faulty turbine building roof drainage system, which allowed water to impact the pump's turbine speed control cabinet. At the end of the inspection period, the licensee was developing an LER for this event in accordance with 10 CFR 50.73.

b. Issues and Findings

No findings were identified.

.2 (Closed) LER 50-413/00-002-00: Bypassed Compensatory Action on ECCS Pump Area Sump Pumps Caused Plant to be in a Condition Outside the Design Basis. This LER described a condition in which control room computer points associated with liquid waste (WL) system sumps located in the ND and NS pump areas were disabled during maintenance activities, which placed the plant in a condition outside of its design basis. This was identified as an NCV.

Background

The high and high-high level alarms associated with the ND/NS pump room sumps are described in the UFSAR as a means for operators to determine that an ECCS system leak has occurred outside containment following a design basis LOCA. The ND/NS pump room sumps are provided with four safety-related pumps that are designed to automatically pump down the sump at the high level setpoint to prevent flooding of ECCS equipment. In October 1998, the licensee discovered that, during plant construction, they failed to install an interlock intended to ensure that the high level alarm would actuate in the control room during a safety injection (SI) signal before the sump pumps automatically pumped down the sump level (this issue was described in LER 50-413/98-016). Corrective actions for the 1998 issue included placing the WL sump pumps in standby to prevent them from starting until the control room alarm was received. In standby, the pumps would still automatically pump the sump down at the high-high level setpoint to protect ECCS equipment. Since October 1998, the licensee has been relying on a control room computer alarm to provide the sump level alarm function until a permanent annunciator window is activated. The control room annunciator and permanent SI interlock installation was scheduled to be completed during the Fall 2000 Unit 1 refueling outage.

Problem Assessment

On February 10, 2000, the licensee found that the computer alarm relied upon to meet the above function had been defeated since August 1999 due to maintenance associated with one of the four sump pump level switches. The work on the level switch had not been completed when this problem was identified. Upon discovery, the computer point was restored and corrective actions to prevent recurrence included increasing the security level on the computer point to require Operations permission before manipulating it. On February 16, 2000, the computer point was deleted again by a maintenance technician who was completing the calibration of the level switch. The computer point was returned to service four hours later after control room operators discovered it during a shift turnover. As a corrective action, the computer point security level was further increased to require an Operations password prior to manipulating it. Further licensee investigation determined that the alarm had been defeated seven other times between October 1998, when the compensatory measure was first established, and August 1999.

The licensee’s root cause evaluation determined that the compensatory action program was not reviewed and integrated into appropriate processes to ensure that requirements were met. The inspectors’ review found that instrument procedure IP/1/A/3181/001, (WL) Safety Related Sump Level Control Switches, Revision 028, which was used to calibrate the level switch on both occasions, was inappropriate for the circumstances. Enclosure 11.6 of the procedure stated that each affected computer point must be deleted from processing or have an appropriate value inserted per information on each point’s summary display. The ND/NS sump level point was among those listed in the enclosure and was deleted after consultation with a senior reactor operator. Failure to provide adequate procedures for performing maintenance on these level switches was considered to be a violation of TS 5.4.1.a and Regulatory Guide 1.33, Appendix A, Section 9. This violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. It is identified as NCV 50-413,414/00-03-05: Failure to Provide Adequate Procedures for Performing Maintenance on Safety-Related Sump Pump Level Switches. The licensee’s corrective actions identified in PIP C-00-00592, which increased the security level of the sump level computer point and addressed weaknesses in how existing processes and procedures are reviewed to incorporate compensatory action program requirements, should preclude recurrence of this event.

Section 6.3.2.5 of the UFSAR stated that the ND/NS sump level alarms are used to confirm excessive leakage from ECCS components, particularly from a seal failure of the ND or NS pumps. The UFSAR states that once the sump alarms confirm excessive leakage, operators determine which train is faulted by measuring flow at the discharge of each ECCS pump, and isolate the faulted train. The LER stated that various radiation monitors and increasing waste tank levels would have provided an indirect indication of excessive leakage to operators during the time that the control room computer alarm was defeated. The inspectors confirmed that most of the radiation monitors were available during this period. Based on the availability of redundant means for detecting ECCS component leaks following a LOCA, the inspectors concluded that this issue was of very low safety significance. This issue was screened in Phase 1 of the SDP as green.

.3 (Closed) LER 50-414/00-001-00: Failure of Diesel Generator Output Breaker Renders the 2B Diesel Generator Inoperable for Longer than Technical Specifications Allow. The inspectors reviewed the proposed and implemented corrective actions and determined them to be adequate. The equipment failure rendered the 2B EDG inoperable from February 7, to March 1, 2000. This period of inoperability, which was calculated to be approximately 528 hours, exceeded the licensee's maintenance rule unavailability limit for Unit 2 Cycle 10 (490.56 hours). Based on this occurrence, the licensee placed the 2B EDG in maintenance rule (a)(1) status. The inspectors concluded that this equipment failure was not reflective of a performance deficiency on the part of the licensee. Specifically, the inspectors determined that the failure which resulted in the inoperable EDG was not the result of any shortcomings in licensee performance. Additionally, it was not reasonable for the licensee to have discovered the degraded condition earlier. Therefore, this event did not constitute a violation of NRC regulatory requirements. This LER is closed.

.4 (Closed) LER 50-413/00-003-00: Use of Control Room Pressure Boundary Compensatory Action Caused Control Room Ventilation System to be Inoperable. This LER described a regulatory issue that was dispositioned as NCV 50-413,414/00-01-02. No new issues were revealed by the LER.

.5 (Closed) LER 50-414/00-002: Inoperable Ignitors on Both Trains of the Hydrogen Ignition System (HIS) Due to a Common Cause Failure Mode of Non Safety-Related Equipment Resulting in a Technical Specification Violation. Discovered during sequential HIS train testing, this common-mode failure was caused by internal changes in the hydrogen ignitor design that were unknown to the licensee. These changes occurred after a new sub-contractor continued production of the igniters (i.e.,glow plugs), utilizing the same part number and application. All accessible igniters in train B and A were replaced with the previous design and tested satisfactorily on April 29 and 30, respectively. On May 5, 2000, the NRC approved an emergency TS change allowing an exception to the requirement of TS 3.6.9 for at least one operable igniter per containment region. Specifically, the inaccessible ignitors (one per train) located beneath the reactor vessel missile shield were allowed to remain inoperable for the remainder of Cycle 11 or until the unit enters Mode 5, which would facilitate their replacement. Both trains of the Unit 2 HIS were subsequently determined to be past inoperable, with the unit unknowingly in TS 3.0.3 from entry into Mode 2 on April 8, 2000, until approval of the NRC emergency TS on May 5, 2000. The inspectors reviewed this LER and PIP C-00-02248 and concluded that this equipment failure was not reflective of a performance deficiency on the part of the licensee. Specifically, the inspectors determined that the failure which resulted in the inoperable igniters was not the result of any shortcomings in licensee performance. Additionally, it was not reasonable for the licensee to have discovered the degraded condition earlier. Therefore, this event did not constitute a violation of NRC regulatory requirements. This LER is closed.

4OA5 Other

a. Inspection Scope

The inspectors conducted a supplemental inspection in accordance with Inspection Procedure 95001 to assess the licensee's evaluation of a white performance indicator reported for first quarter 2000, which involved the unavailability of the Unit 1 B train of ND.

b. Issues and Findings

The high unavailability of this ND system train was due to fault exposure hours that were assigned for second quarter 1997, following the discovery that the 1B ND heat exchanger bypass valve failed to stroke open during a surveillance test. A subsequent review by the licensee determined that the test failure, as well as all of the related fault exposure hours, occurred during a plant operating mode in which the affected system function was not required by TSs. Therefore, the inspectors determined, following consultation with NRR, that the ND system's fault exposure hours had been erroneously reported, and the system's performance was at a level requiring no additional NRC oversight.

4OA6 Meetings

Exit Meeting Summary

The inspectors presented the inspection results to Mr. Gary Peterson, Site Vice President, and other members of licensee management at the conclusion of the inspection on June 27, 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.

Public Meeting Summary

On June 21, 2000, at 7:00 p.m., Mr. C. Ogle (Chief, Branch 1, Division of Reactor Projects, Region II), assisted by Mr. D. Roberts (Senior Resident Inspector - Catawba), held a public presentation at the City Hall in Rock Hill, South Carolina concerning the NRC's Revised Reactor Oversight Process. Seventeen persons attended, including employees of Duke Energy Corporation, local emergency planning officials, local news reporters, and members of the Blue Ridge Environmental Defense League.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

E. Beadle, Emergency Preparedness Manager
R. Beagles, Safety Review Group Manager
M. Boyle, Radiation Protection Manager
G. Gilbert, Regulatory Compliance Manager
R. Glover, Operations Superintendent
P. Grobusky, Human Resources Manager
P. Herran, Engineering Manager
R. Jones, Station Manager
R. Parker, Maintenance Superintendent
G. Peterson, Catawba Site Vice-President
F. Smith, Chemistry Manager
R. Sweigart, Safety Assurance Manager

NRC

Herbert Berkow, Project Director, Region 2 Projects, NRR
Chandu Patel, Project Manager for Catawba, NRR
Frank Rinaldi, Project Manager for McGuire, NRR

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-413,414/00-03-04	URI	Minor Discrepancy Involving the Calculation of Reactor Coolant System Specific Activity Performance Indicator (Section 4OA1.1)

Opened and Closed During this Inspection

50-413,414/00-03-01	NCV	Failure to Scope an Accident Mitigating Function Associated with ECCS Leak Detection in the Maintenance Rule (Section 1R12.2)
50-413,414/00-03-02	NCV	Failure to Prevent the Release of Radioactive Byproduct Material from the Radiological Control Area and Plant Site (Section 2PS3)
50-413,414/00-03-03	NCV	Failure to Secure Two Vital Area Openings Exceeding 96 Square Inches in February 1999 (Section 3PP2)

50-413,414/00-03-05	NCV	Failure to Provide Adequate Procedures for Performing Maintenance on Safety-Related Sump Pump Level Switches (Section 4OA3.2)

Previous Items Closed

2515/144	TI	Performance Indicator Data Collecting and Reporting Process Review (Section 4OA1.2)
50-413/00-002-00	LER	Bypassed Compensatory Action on ECCS Pump Area Sump Pumps Caused Plant to be in a Condition Outside the Design Basis (Section 4OA3.2)
50-414/00-001-00	LER	Failure of Diesel Generator Output Breaker Renders the 2B Diesel Generator Inoperable for Longer than Technical Specifications Allow (Section 4OA3.3)
50-413/00-003-00	LER	Use of Control Room Pressure Boundary Compensatory Action Caused Control Room Ventilation System to be Inoperable (Section 4OA3.4)
50-414/00-002-00	LER	Inoperable Ignitors on Both Trains of the Hydrogen Ignition System Due to a Common Cause Failure Mode of Non Safety-Related Equipment Resulting in a Technical Specification Violation (Section 4OA3.5)

LIST OF ACRONYMS USED

CFR - Code of Federal Regulations
DRU - Digital Reference Unit
ECCS - Emergency Core Cooling System
EDG - Emergency Diesel Generator
EDM - Engineering Directives Manual
EHM - Hydrogen Mitigation
FAQ - Frequently Asked Questions
FFD - Fitness For Duty
GL - Generic Letter

IP - Inspection Procedure
LCO - Limiting Condition for Operation
LOCA - Loss of Coolant Accident
LER - Licensee Event Report
MPFF - Maintenance Preventable Function Failure
NC - Reactor Coolant (also RCS)
nCi - Nanocuries
NCV - Non-Cited Violation
ND - Residual Heat Removal
NEI - Nuclear Energy Institute
NM - Primary Sample
NRC - Nuclear Regulatory Commission
NRR - Nuclear Reactor Regulation
NS - Containment Spray
NSD - Nuclear System Directive
NW - Containment Isolation Valve Water Injection
ORAM - Online Risk Assessment Matrix
PIP - Problem Investigation Process
PORV - Power Operated Relief Valve
PRA - Probabilistic Risk Assessment
psig - Pounds per square inch gauge
PSP - Physical Security Plan
RCA - Radiological Control Area
RCS - Reactor Coolant System
SDP - Significance Determination Process
SG - Steam Generator (also S/G)
SGTR - Steam Generator Tube Rupture
SI - Safety Injection
SSC - Structures, Systems and Components
TEDE - Total Effective Dose Equivalent
TI - Temporary Instruction
TS - Technical Specification
TSAIL - Technical Specification Action Item Log
UFSAR - Updated Final Safety Analysis Report
URI - Unresolved Item
WL - Liquid Waste
WPM - Work Process Manual
μCi/gm - Micro-Curies per gram
μCi-hrs - microCurie-hours

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.