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

July 29, 2005

South Carolina Electric & Gas Company
ATTN: Mr. Jeffrey B. Archie
Vice President, Nuclear Operations
Virgil C. Summer Nuclear Station
P. O. Box 88
Jenkinsville, SC 29065

SUBJECT: VIRGIL C. SUMMER NUCLEAR STATION - NRC INTEGRATED INSPECTION REPORT 05000395/2005003

Dear Mr. Archie:

On June 30, 2005, the United States Nuclear Regulatory Commission (NRC) completed an inspection at your Virgil C. Summer Nuclear Station. The enclosed integrated inspection report documents the inspection findings, which were discussed on July 13, 2005, with Mr. Jeff Archie and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection, one NRC-identified and two self-revealing findings were identified. Two of these findings were determined to involve violations of NRC requirements. However, because of their very low safety significance and because they are entered into your corrective action program, the NRC is treating these findings as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. In addition, four licensee-identified violations, which were determined to be of very low safety significance, are listed in Section 4OA7 of this report. If you contest any NCV in this report, 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 Virgil C. Summer Nuclear Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) 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/reading-rm/adams.html* (the Public Electronic Reading Room).

Sincerely,

/RA/

Kerry D. Landis, Chief
Reactor Projects Branch 5
Division of Reactor Projects

Docket No.: 50-395
License No.: NPF-12

Enclosure: NRC Integrated Inspection Report 05000395/2005003
w/Attachment: Supplemental Information

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U. S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket No.:	50-395
License No.:	NPF-12
Report No.:	05000395/2005003
Licensee:	South Carolina Electric & Gas (SCE&G) Company
Facility:	Virgil C. Summer Nuclear Station
Location:	P. O. Box 88 Jenkinsville, SC 29065
Dates:	April 1, 2005 - June 30, 2005
Inspectors:	J. Zeiler, Senior Resident Inspector M. Cain, Resident Inspector M. King, Resident Inspector J. Blake, Steam Generator Consultant (Section 1R08) J. Fuller, Reactor Inspector (Section 1R08) J. Griffis, Health Physicist (Section 2OS2) R. Hamilton, Senior Health Physicist (Sections 2OS1, 2PS2, 4OA1, and 4OA5) P. VanDoorn, Senior Reactor Inspector (Sections 1R08 and 4OA5.1)
Approved by:	K. D. Landis, Chief Reactor Projects Branch 5 Division of Reactor Projects

Enclosure

CONTENTS

SUMMARY OF FINDINGS

IR 05000395/2005003; 04/01/2005 - 06/30/2005; Virgil C. Summer Nuclear Station; Inservice Inspection Activities, Operator Performance during Non-Routine Evolutions and Events, and Refueling and Outage Activities.

The report covered a three-month period of inspection by resident inspectors and two announced inspections by regional inspectors. One Green NRC-identified non-cited violation (NCV), one Green self-revealing NCV, and one Green Finding was identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using IMC 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. A self-revealing finding was identified for the use of an inadequate on-line leak repair procedure, which resulted in the line break of a 1" diameter Main Steam Turbine Casing Drain / 3rd Stage Extraction Steam Equalization Line. The on-line leak repair procedure, MMP-105.005, did not contain any instruction to verify that the subject piping maintained adequate wall thickness prior to installation of the leak sealant enclosure cavity. The licensee has performed a root cause investigation of the line failure and has entered the results into their corrective action program.

  This finding is greater than minor because the procedure, if left uncorrected, could be applied to more safety significant piping systems where a similar failure could initiate a plant transient or cause complications such as loss of normal heat sink. The finding is considered to be of very low safety significance because it did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment would not be available. The cause of this finding was an evaluation issue of the cross-cutting aspect of Problem Identification and Resolution (Section 1R08).

- Green. A self-revealing non-cited violation of Technical Specification 6.8.1.a was identified for the failure to adequately review and understand the impact of protective relay maintenance/testing on the plant prior to allowing the work to commence.

  This finding is greater than minor because it affected the human performance attribute of the Initiating Events cornerstone and affected the cornerstone objective, in that, the failure to adequately review and understand the impact of the work activity resulted in a perturbation in plant stability by causing a loss of power to the Class 1E "B" train vital safeguards bus (1DB), loss of power to all balance of plant buses, and automatic start of the "B" train emergency diesel generator and actuation of the Engineered Safety Features (ESF) loading

sequencer. The finding is of very low safety significance because all necessary plant safety equipment responded as designed to the loss of power event, shutdown cooling flow was restored within 20 seconds without any appreciable reactor coolant system (RCS) heatup, and all "A" train redundant ESF equipment remained functional during the period. The direct cause of this finding was an organizational issue of the cross-cutting aspect of Human Performance (Section 1R14).

Cornerstone: Mitigating Systems

- Green. The NRC identified a non-cited violation of Technical Specification 6.8.1.a for the failure to place the "B" train Residual Heat Removal (RHR) pump control switch in pull-to-lock (PTL) prior to heating up the reactor coolant system (RCS) greater than 250E F during plant restart from the refueling outage.

  This finding is more than minor because if left uncorrected, it could have resulted in a more significant safety concern, in that, had RCS heatup continued without the "B" RHR pump in PTL, it could have resulted in the pump being incapable of performing its design safety function during shutdown accident conditions. The finding is of very low safety significance because after being alerted by the NRC, the condition was corrected prior to the RCS exceeding temperatures that could have allowed flashing to occur in the "B" RHR pump suction piping had the pump automatically started and aligned to the refueling water storage tank. The direct cause of this finding was an attention issue of the cross-cutting aspect of Human Performance (Section 1R20).

B. Licensee-Identified Violations

Four violations of very low safety significance, which were identified by the licensee, have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. These violations and the associated corrective action tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

The unit began the inspection period at 100 percent rated thermal power (RTP). On April 18, power was reduced to 90 percent to support planned maintenance on the “A” main feedwater pump. On April 21, power was reduced to 80 percent to support planned main steam safety valve testing. On April 23, the unit completed a planned shutdown (Mode 3) to commence the fifteenth refueling outage (RF-15). Following RF-15, criticality and Mode 1 were achieved on May 31 and June 1, respectively. The unit was returned to 100 percent RTP on June 6 and remained at or near full power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection

a. Inspection Scope

The inspectors performed one adverse weather inspection for readiness of extreme hot weather. The inspectors evaluated implementation of adverse weather procedure operations administrative procedure (OAP)-109.1, “Guidelines for Severe Weather,” for the main generator breaker cooling and air system, isophase bus duct cooling system, and motor stator temperatures for large balance of plant pumps.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

.1 Availability of Redundant Equipment

a. Inspection Scope

The inspectors conducted three partial equipment alignment walkdowns (listed below) to evaluate the operability of selected redundant trains or backup systems with the other train or system inoperable or out-of-service (OOS). Correct alignment and operating conditions were determined from the applicable portions of drawings, system operating procedures (SOPs), final safety analysis report (FSAR), and technical specifications (TS). The inspections included review of outstanding maintenance work requests (MWRs) and related condition evaluation reports (CERs) to verify that the licensee had properly identified and resolved equipment alignment problems that could impact mitigating system availability. Documents reviewed are listed in the Attachment.

- “A” motor driven emergency feedwater (MDEFW) pump while “B” MDEFW pump was OOS due to planned maintenance/surveillance testing;

- “A” emergency diesel generator (EDG) walkdown while the “B” EDG was OOS for planned maintenance and testing; and,
- “A” residual heat removal (RHR) system walkdown while the “B” RHR system was OOS for planned maintenance.

b. Findings

No findings of significance were identified.

.2 Semiannual Inspection: RHR System

a. Inspection Scope

The inspectors performed a detailed review and walkdown of the RHR system and related support systems to identify any discrepancies between the current operating system equipment lineup and the designed lineup. This walkdown included accessible areas inside the containment during the refueling outage and outside containment. In addition, the inspectors reviewed completed surveillance procedures, outstanding MWRs, leakage assessments and RHR system related CERs to verify that the licensee had properly identified and resolved equipment problems that could affect the availability and operability of the RHR system. The inspectors also reviewed the work packages, contingency planning, risk assessments, and actual field work during implementation of engineering change request (ECR)-50316, “Automatic Transfer to the Reactor Building Sump,” performed during RF-15. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors reviewed recent CERs, MWRs, and impairments associated with the fire suppression system. The inspectors reviewed surveillance activities to determine whether they supported the operability and availability of the fire protection system. The inspectors assessed the material condition of the active and passive fire protection systems and features and observed the control of transient combustibles and ignition sources. The inspectors conducted routine inspections of the following nine areas (respective fire zones also noted):

- 1DA switchgear room (fire zone IB-20);
- Relay room solid state protection system instrumentation and inverter (fire zones CB-6, CB-10, and CB-12);
- 1DB switchgear and heating, ventilation, and air-conditioning (HVAC) rooms (fire zones IB-16, IB-17, and IB-22.2);

- Intermediate building component cooling water pumps, heat exchangers, and service water booster pumps (fire zones IB-25.1.1, 1.2, 1.3, 1.5);
- "A" and "B" EDG rooms (fire zones DG-1.1, 1.2, DG-2.1, 2.2);
- "A" and "B" HVAC chilled water pump rooms (fire zones IB-7.2, IB-9, IB-23.1);
- Turbine driven emergency feedwater (TDEFW) pump room (fire zone IB-25.2);
- "A" and "B" battery and charger rooms (fire zones IB-2, 3, 4, 5 & 6); and,
- "A," "B," and "C" charging pump rooms (fire zones AB-1.5, AB-1.6, AB-1.7).

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

a. Inspection Scope

The inspectors reviewed and walked down two areas (i.e., Intermediate Building 412' elevation and EDG Building) regarding internal flood protection features and equipment to determine consistency with design requirements, FSAR and flood analysis documents. Risk significant structures, systems, and components in these areas included the 125 volt direct current safety-related batteries and associated chargers, Reactor Building HVAC chillers, component cooling water pumps, service water booster and emergency feedwater pumps, EDGs, and EDG fuel oil transfer system. The inspectors reviewed the licensee's corrective action program (CAP) database to verify that internal flood protection problems were being identified at the appropriate level, entered into the CAP, and appropriately resolved. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (ISI) Activities

.1 Piping Systems ISI

a. Inspection Scope

On April 25-29 and May 9-13, 2005, the inspectors reviewed the implementation of the licensee's ISI program for monitoring degradation of the reactor coolant system boundary and the risk significant piping system boundaries. The inspectors selected a sample of American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI required examinations and Code components in order of risk priority.

The inspectors conducted an on-site review of nondestructive examination (NDE) activities to evaluate compliance with TS, ASME Section XI, and ASME Section V requirements, 1998 Edition through 2000 Addenda, and to verify that indications and defects (if present) were appropriately evaluated and dispositioned in accordance with the requirements of ASME Section XI, IWB-3000 or IWC-3000 acceptance standards.

Specifically, the inspectors observed the following examinations:

Visual Testing (VT):
- Pressurizer Relief Nozzle, ASME Class 1
- Three Pressurizer Safety Nozzles, ASME Class 1
- Pressurizer Spray Nozzle, ASME Class 1

Specifically, the inspectors reviewed the following examination records:

Ultrasonic Testing (UT):
- CGE-1-4502-13/Reactor Coolant System (RCS), Pressurizer Relief, Pipe to Tee, ASME Class 1
- CGE-2-2523A-19/RHR “B”, Residual Heat Removal, Pipe to Elbow, ASME Class 2

The inspectors reviewed examination records for the following recordable indications to evaluate if the licensee’s acceptance was in accordance with acceptance standards contained in Article IWB-3000 of ASME Section XI.

Ultrasonic Testing (UT):
- CGE-1-4501-14/RCS, Pressurizer Safety, Pipe to Elbow, ASME Class 1
- CGE-1-4501-16/RCS, Pressurizer Safety, Pipe to Elbow, ASME Class 1
- CGE-1-2100B, Pressurizer Nozzle to Head weld, ASME Class 1

Qualification and certification records for examiners, inspection equipment, and consumables along with the applicable NDE procedures for the above ISI examination activities were reviewed and compared to requirements stated in ASME Section V and Section XI.

In addition, the inspectors observed an UT of a component (8-inch Feedwater Area No. 081-T12-21) for flow accelerated corrosion (FAC) to confirm qualified personnel were performing the inspection in accordance with established guidelines. The inspectors also observed a FAC examination that was a result of industry operating experience on a 24" condensate line (Heater 4A/B to DEA-5).

The inspectors performed a review of ISI related problems that were identified by the licensee and entered into the corrective action program as CERs. The inspectors reviewed these CERs to confirm that the licensee had appropriately described the scope of the problems and had initiated corrective actions. The inspectors also reviewed a licensee audit of the Inservice Testing and ISI programs to confirm problems were documented in the corrective action program and properly addressed.

b. Findings

Introduction. A Green self-revealing finding was identified for the use of an inadequate on-line leak repair procedure, which resulted in the line break of a 1" diameter Main Steam Turbine Casing Drain / 3rd Stage Extraction Steam Equalization Line.

Description. On December 6, 2004, a steam leak was identified in the turbine building, and a controlled plant shutdown was commenced to investigate the steam leak. After the plant shutdown, it was determined that a 1" diameter Extraction Steam line under the turbine had ruptured. A pin-hole leak was identified in April 2004 in the drain line at the toe of a socket weld. In May 2004, an external clamp-on enclosure was installed around the pin-hole leak per mechanical maintenance procedure (MMP)-105.005, “On-Line Sealant Repairs,” Rev. 4, and MWR 0410053. This procedure was applied as a temporary repair until a permanent repair could be implemented during the next refueling outage. Three days after the temporary enclosure was installed one end of the enclosure began to leak. A second injection into the enclosure was performed on May 18, 2004, and the leak stopped. The enclosure did not leak until it failed in December 2004. The licensee concluded that the break was caused by propagation of a small crack that occurred during the on-line leak repair of a small through-wall hole created by FAC induced pipe thinning. The on-line leak repair procedure, MMP-105.005, did not contain any instruction to verify that the subject piping maintained adequate wall thickness prior to installation of the leak sealant enclosure cavity. The licensee’s investigation revealed that the failure to quantify the wall thickness at the coupling contributed to cracking the pipe and over stressing the joint, and that maximum injection pressure did not consider the structural integrity of the thinned pipe. The minimum allowable wall thickness for this piping is 0.052 inches, with an actual as-found thickness of 0.028 inches. This thinning was attributed to FAC, specifically a FAC phenomena called the “Entrance Effect,” where the upstream piping is a FAC resistant material such as Chrome-Moly, but the downstream piping is a FAC susceptible material such as Carbon Steel.

Analysis. The performance deficiencies associated with this self-revealing finding were (1) the application of an inadequate on-line leak repair procedure, in that, it did not require verification of the structural integrity (wall thickness) of the piping prior to the installation of the leak sealing enclosure and subsequent sealant injection, (2) the licensee did not maintain accurate design documents (plant drawings), which failed to reflect the “as-installed” configuration (Schedule 80 Chrome-Moly instead of Schedule 40 Carbon steel), and (3) the licensee did not provide an accurate FAC susceptibility analysis of this drain / equalization line in that the actual flow conditions and thus the active corrosion mechanism (FAC) was not identified. These performance deficiencies resulted in a finding that is greater than minor because the procedure, if left uncorrected, could be applied to more safety significant piping systems where a similar failure could initiate a plant transient or cause complications such as loss of normal heat sink. This finding is associated with the procedure quality and design control attributes of the Initiating Events cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during a shutdown as well as at power operations. This finding was an evaluation issue of the cross-cutting aspect of

Problem Identification and Resolution, in that, the licensee's initial corrective actions presented an opportunity to evaluate the "as-installed" configuration, the active corrosion mechanism (FAC), and the incorrect design drawings upon discovery of the initial pin-hole leak. The finding was processed through the significance determination process (SDP) and determined to be of very low safety significance (Green) because it did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment would not be available.

Enforcement. No violation of regulatory requirements occurred. The inspectors determined that the finding did not represent a noncompliance because the procedure is not required by regulation. FIN 05000395/2005003-01, Failure of 1" Extraction Steam Line Due to Inadequate On-Line Leak Repair Procedure.

.2 PWR Vessel Upper Head Penetration Inspection Activities

a. Inspection Scope

The inspectors reviewed activities to ensure licensee compliance with the requirements of NRC Order EA-03-009. The inspectors reviewed the scope of the licensee's activities as they relate to examination of the pressure retaining components above the reactor pressure vessel (RPV) head to ensure that all possible sources of boric acid leakage were included, that the examination would be effective in identifying boric acid leakage in this area, and that appropriate actions would be implemented should boron deposits be identified on the RPV head or related insulation.

b. Findings

No findings of significance were identified.

.3 Boric Acid Corrosion Control (BACC) ISI

a. Inspection Scope

On May 9-13, 2005, the inspectors reviewed the licensee's BACC program to ensure compliance with commitments made in response to NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary," and Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity."

The inspectors conducted an on-site record review as well as an independent walk-down of parts of the reactor building that are not normally accessible during at-power operations to evaluate compliance with licensee BACC program requirements and 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. In particular, the inspectors verified that the boric acid visual examinations focused on locations where boric acid leaks can cause degradation of safety significant components and that degraded or non-conforming conditions were properly identified in the licensee's corrective action system.

The inspectors reviewed the licensee's procedures for implementation of the boric acid corrosion control program to ensure that they were in accordance with available industry guidance. The inspectors reviewed a sample of engineering evaluations completed for boric acid found on reactor coolant system piping and components to verify that the minimum design code required section thickness had been maintained for the affected component(s). The inspectors also reviewed licensee corrective actions implemented for evidence of boric acid leakage to confirm that they were consistent with requirements of Section XI of the ASME Code and 10 CFR 50, Appendix B, Criterion XVI. Specifically, the inspectors reviewed the following engineering evaluations:

- Non-minor Boric Acid Leak from packing on valve XVT08878C-SI, Accumulator C Fill Inlet Valve (CER 05-1366);
- Bolted Connection Inspection of Pressurizer Power Operated Relief Valve XVG08000C-RC, ASME Class 1, non-minor boric acid accumulation on body/bonnet joint (CER 05-1378);
- Bolted Connection Inspection of Pressurizer Power Operated Relief Valve XVG08000A-RC, ASME Class 1, non-minor boric acid accumulation on body/bonnet joint (CER 05-1429);
- Bolted Connection Inspection of Pressurizer Power Operated Relief Valve XVG08000B-RC, ASME Class 1, non-minor boric acid accumulation on body/bonnet joint (CER 05-1430).

b. Findings

No findings of significance were identified.

.4 Steam Generator (SG) Tube ISI

a. Inspection Scope

On May 9-13, 2005, the inspectors reviewed the SG tube examination activities conducted pursuant to TS and the ASME Code Section XI requirements.

The inspectors reviewed the SG examination scope, expansion criteria, eddy current testing (ET) acquisition procedures, ET analysis procedures, the SG Condition Monitoring and Operational Assessment, and the SG Degradation Assessment, which consisted of:

- Bobbin Coil examination of 100% of tubes in each Steam Generator;
- Rotating Pancake Coil (RPC) examination of hot leg expansion transitions in 20% of tubes in each Steam Generator;
- RPC examination of all service related dents/dings greater than 2.00 volts that were not present during the 1994 baseline examination, all previous dents/dings with bobbin voltages equal to or greater than 5 volts and a 20% sample of previous dents/dings with bobbin voltages between 2 and 5 volts. All previous dents/dings in the U-bends with bobbin voltages greater than 3 volts were examined with the Plus Point;

- RPC examination of 20% low row U-bends in SG “A”;
- RPC examination of areas of interest included: SG “A” – 31 tubes, SG “B” – 34 tubes, and SG “C” – 53 tubes.

Additionally, the inspectors reviewed the SG tube ET examination scope to determine that it was consistent with that recommended in Electric Power Research Institute (EPRI) 1003138, “Pressurized Water Reactor Steam Generator Examination Guidelines,” Revision 6, and included tube areas which represent ET challenges such as the tubesheet regions, expansion transitions, U-bends and support plates.

The inspectors reviewed the licensee examination techniques sheets to verify that the ET probes and equipment configurations used to acquire ET data from the SG tubes were qualified to detect the known/expected types of SG tube degradation in accordance with Appendix H, “Performance Demonstration for Eddy Current Examination,” of EPRI 1003138, “Pressurized Water Reactor Steam Generator Examination Guidelines,” Revision 6.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program

a. Inspection Scope

On June 22, 2005, the inspectors observed performance of senior reactor operators and reactor operators on the plant simulator during licensed operator requalification training. The training scenario (LOR-ST-067) involved a 220 gallon per minute steam generator tube leak. The inspectors verified that training included risk-significant operator actions and implementation of emergency classification and the emergency plan. The inspectors assessed overall crew performance, communication, oversight of supervision, and the evaluators' critique. The inspectors verified that any training issues were appropriately captured in the licensee’s CAP.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors evaluated two equipment issues described in the CERs listed below to verify the licensee’s effectiveness of the corresponding preventive or corrective maintenance associated with structures, systems or components (SSCs). The inspectors reviewed maintenance rule (MR) implementation to verify that component and equipment failures were identified, entered, and scoped within the MR program.

Selected SSCs were reviewed to verify proper categorization and classification in accordance with 10 CFR 50.65. The inspectors examined (a)(1) corrective action plans to determine if the licensee was identifying issues related to the MR at an appropriate threshold and that corrective actions were established and effective. The inspectors' review also evaluated if maintenance preventable functional failures (MPFF) or other MR findings existed that the licensee had not identified. The inspectors reviewed the licensee's controlling procedures, i.e., engineering services procedure (ES)-514, "Maintenance Rule Implementation," and the Virgil C. Summer "Important To Maintenance Rule System Function and Performance Criteria Analysis" to verify consistency with the MR requirements.

- CERs 0-C-04-3775 and 0-C-05-1044, high pressure turbine extraction drain line failure resulting in plant shutdown; and,
- CER 0-C-05-0708, charging springs for "B" charging pump breaker XSW1DB09 failure to charge when racked into the operate position.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors reviewed the licensee's assessments of the risk impacts of removing from service those components associated with planned and emergent work items. The inspectors evaluated the five selected work activities listed below for: (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 emergent work problems were adequately identified and resolved. The inspectors evaluated the licensee's work prioritization and risk characterization to determine, as appropriate, whether necessary steps were properly planned, controlled, and executed for the planned and emergent work activities listed below:

- "B" MDEFW pump OOS for scheduled preventive maintenance;
- Parr 115 kilovolt (kV) offsite power line OOS for five days for electrical substation work on circuit breakers OCB8772 and OCB8792 and testing of engineered safety features (ESF) transformers XTF0004 and XTF0006;
- Review of shutdown risk and contingency plans for RCS inventory at nine inches below the reactor vessel flange;
- Review of shutdown risk and contingency plans for one train of ESF equipment available, refueling reactor core, and "B" spent fuel pool pump on alternate power; and,
- "B" RHR pump OOS for scheduled preventive maintenance.

b. Findings

No findings of significance were identified.

1R14 Operator Performance During Non-Routine Evolutions and Events

a. Inspection Scope

The inspectors evaluated operator response and preparations for the two listed non-routine events to ensure they were appropriate and in accordance with the required procedures. The inspectors also evaluated performance and equipment problems to ensure that they were entered into the CAP.

- May 4, Unusual Event declared due to a fire within protected area (in the refueling cavity) lasting greater than 15 minutes (CER 0-C-05-1685); and,
- May 18, loss of power to the "B" train Class 1E switchgear and all balance of plant buses (CER 0-C-05-2042).

b. Findings

No findings of significance were identified with the operator actions in response to the events; however, the following finding was identified with a human performance error that caused the loss of power to the "B" train Class 1E switchgear event.

Introduction. A Green self-revealing non-cited violation (NCV) of TS 6.8.1.a was identified for the failure to adequately review and understand the impact of relay maintenance/testing resulting in loss of power to the Class 1E "B" train vital safeguards bus (1DB), all balance of plant buses, automatic start of the "B" EDG and actuation of the "B" train ESF loading sequencer.

Description. On May 18, the plant was in Mode 5 (Cold Shutdown) with the reactor refueled, the RCS level at 9 inches below the vessel flange, and the "B" RHR pump in operation supplying shutdown cooling. During protective relay maintenance/testing in accordance with electrical maintenance procedure (EMP)-405.024, "Testing of Type HEA61, HEA63, and LOR Relays," differential lockout relay 86T3 was manually actuated as part of the procedure resulting in the actual lockout (isolation) of emergency auxiliary transformers XTF31 and XTF32. These transformers were supplying power to the "B" train safeguards bus, as well as all balance of plant switchgear buses. As a result of the lockout, power was lost to both the 1DB and balance of plant buses, resulting in an automatic start of the "B" EDG and actuation of the "B" train ESF loading sequencer. All important plant safety equipment responded to the event as designed and the "B" train RHR system was returned to full shutdown cooling flow conditions within approximately 20 seconds. During this period, the inlet temperature of the "B" RHR heat exchanger only increased approximately 0.3E F and there was no perturbation in RCS level.

Analysis. The inspectors determined that the licensee's failure to adequately review and understand the impact of the relay activities on the plant was a performance deficiency. Specifically, an operator, who approved performance of the procedure, failed to recognize that the procedure would de-energized emergency auxiliary transformers XTF31 and XTF32 which were suppling power to their associated buses. Furthermore, personnel, who were to perform the procedure, failed to explain expected equipment response. This finding is more than minor because it affected the human performance attribute of the Initiating Events cornerstone and affected the cornerstone objective, in that, the failure to adequately review and understand the impact of the work activity resulted in a perturbation in plant stability by causing a loss of power to the "B" train safeguards bus, loss of power to all balance of plant buses, and automatic start of the "B" train EDG and actuation of the ESF loading sequencer. An SDP Phase 1 analysis using Appendix G, for shutdown conditions, determined the finding to be of very low safety significance (Green) because all necessary plant safety equipment responded as designed to the loss of power event, RHR shutdown cooling was restored within 20 seconds without any appreciable RCS heatup, and all "A" train redundant ESF equipment remained functional during the period. The direct cause of this finding involved an organization issue of the cross-cutting aspect of Human Performance.

Enforcement. TS 6.8.1.a requires, in part, that written procedures be established, implemented and maintained covering activities listed in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978, which includes procedures for controlling the authorization of maintenance activities (Section 9.e). OAP-100.6, "Control Room Conduct and Control of Shift Activities," Rev. 0, was written, in part, to provide instructions for conducting onshift work control activities. Step 17.11 of OAP-100.6 requires that prior to releasing work, the work authorizer should review the impact of the work on the plant. Contrary to the above, on May 18, 2005, the operator authorizing relay preventive maintenance/testing associated with emergency auxiliary transformers XTF31and XTF32, failed to adequately review and understand the impact of the work on the plant which resulted in loss of power to the "B" train safeguards bus and automatic start of the "B" train EDG and ESF loading sequencer. Because the finding is of very low safety significance and has been entered into the corrective action program as CER 0-C-05-2042, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000395/2005002-02, Failure to Adequately Review and Understand the Impact of Relay Maintenance Resulting in Loss of "B" Train Safeguards Bus and Automatic Start of "B" EDG and ESF Loading Sequencer.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed five operability evaluations affecting risk significant mitigating systems to assess, as appropriate: (1) the technical adequacy of the evaluations; (2) whether operability was properly justified and the subject component or system remained available, such that no unrecognized increase in risk occurred; (3) whether other existing degraded conditions were considered; (4) where compensatory measures were involved, whether the compensatory measures were in place, would work as intended, and were appropriately controlled; and (5) the impact on TS limiting conditions for operations and the risk significance in accordance with the SDP. Also, the inspectors verified that the operability evaluations were performed in accordance with procedure Station Administrative Procedure (SAP)-1131, “Corrective Action Program.”

- CER 0-C-04-3419, outage results of service water to Emergency Feedwater (EFW) backup supply inspections (tubercle issues);
- CER 0-C-05-1116, snubber acceleration test results outside acceptable limits specified in Surveillance Test Procedure (STP)-803.003 for PSA-10 mechanical snubber MK-SWH-0030, service water system;
- CER 0-C-05-1261, stroking main steam power operated relief valve IPV2010 open caused the closure of EFW to steam generator “A” flow control valve IFV3536-EF;
- CER 0-C-05-2209, “B” MDEFW pump operated in runout flow condition during testing; and,
- CER 0-C-05-2299, pressurizer safety valve XVS8010C leaking by seat.

b. Findings

No findings of significance were identified.

1R16 Operator Work-arounds

a. Inspection Scope

The inspectors reviewed the licensee’s list of identified operator work-arounds, burdens, and challenges to determine whether any new items since the previous inspection period would adversely affect the operators’ ability to implement abnormal or emergency operating procedures. No risk significant operator work-arounds were identified during this inspection period.

Additionally, the inspectors reviewed the licensee’s list of identified operator work-arounds, burdens, and challenges to assess the cumulative effect on the functional capability, reliability or availability of any related mitigating system. The inspectors reviewed the human reliability aspect of the cumulative effect of the work-arounds to determine if they affected the operators’ ability to respond in a correct and timely manner to any initiating event or their ability to implement abnormal or emergency operating procedures.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

a. Inspection Scope

The inspectors reviewed the following two permanent plant modifications (ECRs) during this inspection period.

- ECR-50600, "B" EDG Local Control Panel Wiring Enhancements; and,
- ECR-50316, Automatic Transfer to the Reactor Building (RB) Sump.

The purpose of these reviews were to evaluate the modifications for adverse effects on system availability, reliability, and functional capability. The attributes of the modifications reviewed are as follows:

- Field installation;
- Materials/components compatibility, functionality and consistency with design bases;
- Post-modification testing and performance; and,
- Plant procedure, critical drawing, design basis information, and FSAR updating.

For the selected modification packages, the inspectors observed the as-built and as-left configurations. Documents reviewed included procedures, engineering calculations, modifications design and implementation packages, MWRs, site drawings, corrective action documents, applicable sections of the FSAR, supporting analyses, TS, and design basis information. The inspectors also reviewed CER 0-C-05-1786, I&C technician failed to complete installation step as instructed in ECR 50316 resulting in post-maintenance testing failure.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing

a. Inspection Scope

For the six maintenance activities listed below, the inspectors reviewed the associated post-maintenance testing (PMT) procedures and witnessed either the testing and/or reviewed test records 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) test 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; and (8) equipment was returned to the status required to perform its safety function. The inspectors verified that these activities were performed in accordance with general test procedure (GTP)-214, “Post Maintenance Testing Guideline.”

- MWR 0403073, PMT for “B” MDEFW following scheduled outage maintenance;
- MWR 0506638, PMT for troubleshooting electrical interaction in 7300 process cabinet when steam dump mode selector switch for 1PV02010 is manipulated;
- MWR 0501684, PMT for ECR 50316, automatic transfer to the RB sump for XPN-7020;
- MWR 0410839, NCN 05-1831 repair of “A” service water booster pump discharge check valve, XVC03135A-SW;
- MWRs 0502349 and 0502352, PMT for safety injection valves XVG08811B-0-SI, XVG08812B-0-SI for ECR 50316, automatic transfer to the RB sump; and
- MWR 0402122, PMT for feedwater valve XVK1633A-FW.

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities

a. Inspection Scope

On April 22, the unit began refueling outage RF-15. The 39 day outage was completed on June 1. The inspectors used inspection procedure 71111.20, “Refueling and Outage Activities,” to complete the inspections described below.

Prior to and during the outage, the inspectors reviewed the licensee’s outage risk assessments and controls for the outage schedule to verify that the licensee had appropriately considered risk, industry experience and previous site specific problems, and to confirm that the licensee had mitigation/response strategies for losses of any key safety functions.

In the area of licensee control of outage activities, the inspectors reviewed equipment removed from service to verify that defense-in-depth was maintained in accordance with applicable TS and that configuration changes due to emergent work and unexpected conditions were controlled in accordance with the outage schedule and risk control plan.

The inspectors reviewed selected components which were removed from service to verify that tags were properly installed and that associated equipment was appropriately configured to support the function of the clearance.

During the outage, the inspectors:

- Reviewed RCS pressure, level, and temperature instruments to verify that those instruments were installed and configured to provide accurate indication;
- Reviewed the status and configuration of electrical systems to verify that those systems met TS requirements and the licensee’s outage risk control plan. The

inspectors also evaluated if switchyard activities were controlled commensurate with their risk significance and if they were consistent with the licensee's outage risk control assessment assumptions;
- Observed spent fuel pool operations to verify that outage work was not impacting the ability of the operations staff to operate the spent fuel pool cooling system during and after core offload. The inspectors also reviewed the licensee's calculations of spent fuel pool and reactor vessel heatup rates in case of a potential loss of cooling event;
- Observed licensee control of containment penetrations and containment entries to verify that the licensee controlled those penetrations and activities in accordance with the appropriate TS and could achieve/maintain containment closure for required conditions; and,
- The inspectors examined all accessible areas inside the RB prior to reactor startup to verify that debris had not been left which could affect the performance of the containment sumps.

The inspectors also reviewed the following activities for conformance to applicable procedural and TS requirements:

- Plant shutdown activities;
- Decay heat removal system operations;
- Inventory controls and measures to provide alternate means for inventory addition;
- Reactivity controls;
- Reactor vessel defueling and refueling operations; and,
- Reactor heatup, mode changes, initial criticality, startup and power ascension activities.

The inspectors reviewed various problems that arose during the outage to verify that the licensee was identifying problems related to outage activities at an appropriate threshold and entering them in the CAP. The more significant CERs that were specifically reviewed by the inspectors are listed below.

- CER 0-C-05-1728, broken screws from tube plugs found in feedwater heater 1A;
- CER 0-C-05-1899, "A" service water booster pump discharge check valve had excessive wear in disk hinge;
- CER 0-C-05-2042, loss of power to 1DB and balance of plant buses during protective relay maintenance resulting in EDG automatic start and actuation of ESF loading sequencer;
- CER 0-C-05-2178, failure to maintain 115 kV bus voltage above required limits during maintenance on emergency transformers XTF31 and XTF32;
- CER 0-C-05-2224, unable to draw steam bubble in the pressurizer due to inadequate setup of pressurizer spray valves;
- CER 0-C-05-2289, tuberculation noted upstream and downstream of service water check valve XVC-3120A;
- CER 0-C-05-2286, failure to place "B" RHR in pull-to-lock in accordance with procedures during RCS heatup;

- CER 0-C-05-2298, TS 3.0.3 entry due to all feedwater isolation valves being rendered inoperable while filling the feedwater system in Mode 3;
- CER 0-C-05-2300, TS 3.0.4 violation due to “A” MDEFW pump being left in pull-to-lock during Mode 3 entry;
- CER 0-C-05-2305, TDEFW turbine would not remain reset due to trip tappet assembly being misaligned; and,
- CER 0-C-05-2340, Cycle 16 Core Operating Limits Report was not issued in a timely manner before Mode 2 entry.

b. Findings

Introduction. A Green NCV of TS 6.8.1.a was identified by the NRC for the failure to place the “B” train RHR pump control switch in pull-to-lock (PTL) prior to entering Mode 4 and heating up the RCS greater than 250E F.

Description. On May 27, 2005, at 7:20 a.m., the plant entered Mode 4 during plant restart from the refueling outage. Shortly thereafter, RCS heatup continued with the suction of both RHR pumps aligned to the RCS for Cold Overpressure Protection as required by TS. The “A” train RHR system was in service supplying shutdown cooling and the “B” train RHR system was required to be aligned for standby operation to meet its TS 3.5.3 Emergency Core Cooling System (ECCS) accident mitigation function in Mode 4. At 9:41 a.m., with the RCS temperature at approximately 258E F, an NRC inspector noticed that the “B” RHR pump control switch was not in PTL. Recognizing that plant startup procedures required this configuration when the RCS was greater than 250E F, the inspector alerted the control room operators to the discrepancy. The operators placed the pump control switch in PTL and the Shift Supervisor directed the heatup to be halted. Subsequently, a timeout was called in order to review the startup procedures to ensure no other procedure steps had been missed. No other problems were identified.

In the event of a Loss of Coolant Accident (LOCA) in Mode 4, the non-operating RHR pump fulfilling its ECCS function (i.e., the “B” train pump) needed to be in PTL above 250E F. This temperature limit assures that flashing will not occur if the pump must be aligned to the refueling water storage tank (RWST). If flashing were to occur at the RHR pump suction, the pump could be damaged preventing it from performing its design accident safety function. The “B” RHR pump was required to be in PTL when the RCS was greater than 250E F in accordance with Caution 3.11 of General Operating Procedure (GOP)-2, “Plant Startup and Heatup (Mode 5 to Mode 3),” and Section G of SOP-115, “Residual Heat Removal.” Step 3.11 of GOP-2 required that the operators implement Section G, “Plant Heatup Using RHR Train A,” when the RCS was between 187E F and 193E F (i.e., before entry into Mode 4). Section G of SOP-115 provided instructions for placing the “B” RHR pump in PTL prior to the plant entering Mode 4. The licensee’s investigation into the incident identified that the Control Room Supervisor signed off Step 3.11 without having implemented Section G of SOP-115 due to an erroneous assumption that the intent of the step was already met in the existing configuration.

The licensee re-evaluated the temperature at which flashing would occur in the RHR pump suction piping if a Safety Injection signal occurred in Mode 4. Taking into account conservative assumptions that were used during the initial calculation, the licensee determined that greater margin was available. The licensee's re-analysis of the condition concluded that flashing would not have occurred until RCS temperatures had reached approximately 274E F. Based on the results of this evaluation, it was concluded that the pump would have been capable of performing its safety function at 258E F.

Analysis. This finding is more than minor because if left uncorrected, it could have resulted in a more significant safety concern, in that, had plant heatup continued without the "B" RHR pump in PTL, it could have resulted in the pump being incapable of performing its design safety function during shutdown accident conditions. An SDP Phase 1 analysis determined the finding to be of very low safety significance (Green) because after being alerted by the NRC, the condition was corrected prior to the RCS exceeding temperatures necessary for potential flashing to occur in the "B" RHR pump suction piping had the pump automatically started and aligned to the RWST. Therefore, the "B" RHR pump would have been capable of performing its design safety function. The direct cause of this finding involved an attention issue of the cross-cutting aspect of Human Performance.

Enforcement. TS 6.8.1.a requires, in part, that written procedures be implemented covering activities listed in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978, which includes procedures for plant startup. Licensee general operating procedure GOP-2, "Plant Startup and Heatup (Mode 5 to Mode 3)," Rev. 13, Step 3.11, requires that system operating procedure SOP-115, "Residual Heat Removal," Rev. 19, be implemented to align the RHR system to support plant heatup. SOP-115, Section G, "Plant Heatup Using RHR Train A," requires the "B" RHR pump be placed in PTL prior to Mode 4 entry. Contrary to the above, on May 27, 2005, the Control Room Supervisor failed to follow Step 3.11 of GOP-2 resulting in the "B" RHR pump not being placed in PTL prior to Mode 4 entry, nor prior to RCS heatup greater than 250E F. Because the finding is of very low safety significance and has been entered into the corrective action program as CER 0-C-05-2286, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000395/2005003-03, Failure to Follow Startup Procedure for Aligning RHR System During Plant Heatup.

1R22 Surveillance Testing

a. Inspection Scope

For the seven surveillance tests listed below, the inspectors examined the test procedure and either witnessed the testing and/or reviewed test records to determine whether the scope of testing adequately demonstrated that the affected equipment was functional and operable:

- STP-401.002, "Main Steam Line Code Safety Valves ASME OM Code Test," Rev. 12 (In-service Test);

- STP-454.002, “Control Room Emergency Air Cleanup System Performance Test,” Rev. 4;
- STP-230.006A, “ECCS/Charging Pump Operability Testing (Refueling),” Rev. 5;
- STP-105.017B, “Train “B” Automatic Sump Swapover Post Mod Testing,” Rev. 0;
- STP-215.004, “Containment Isolation Valve Leakage Test for the AC, CC, DN, FS, and SW Systems,” Rev. 6 (for Penetration XRP0312) (Containment Test);;
- STP- 125.010, “Integrated Safeguards Test Train A,” Rev. 11, and;
- STP- 125.011, “Integrated Safeguards Test Train B,” Rev. 11.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstones: Occupational Radiation Safety and Public Radiation Safety

2OS1 Access Control To Radiologically Significant Areas

a. Inspection Scope

Licensee activities for monitoring workers and controlling access to radiologically significant areas were inspected. The inspectors evaluated procedural guidance and directly observed implementation of administrative and physical controls; appraised radiation worker and technician knowledge of, and proficiency in implementing, radiation protection program activities; and assessed worker exposures to radiation and radioactive material.

Radiological postings and material labeling were directly observed during tours of the auxiliary and reactor buildings and radwaste processing areas. The inspectors conducted independent surveys in these areas to verify posted radiation levels and to compare with current licensee survey records. During plant tours, control of Locked High Radiation Area (LHRA) keys and the physical status of LHRA doors were examined. In addition, the inspectors observed radiological controls for non-fuel items stored in the spent fuel pools. The inspectors also reviewed selected Radiation Protection procedures and radiation work permits (RWPs), and discussed current access control program implementation with Radiation Protection supervisors.

During the inspection, radiological controls for work activities in High Radiation Areas (HRA) were observed and discussed. The inspectors attended a pre-job briefing for work that involved entries into posted locked high radiation areas and directly observed the work activities involved. The inspectors observed workers’ adherence to RWP guidance and Health Physics Technician (HPT) proficiency in providing job coverage. Controls for limiting exposure to airborne radioactive material were reviewed and operation of ventilation units and positioning of air samplers were also observed. The inspectors evaluated electronic dosimeter alarm setpoints for consistency with radiological conditions in and around the containment, auxiliary building and radwaste processing areas. In addition, the inspectors interviewed workers to assess knowledge of RWP requirements.

The inspectors evaluated worker exposures through review of data associated with discrete radioactive particle and dispersed skin contamination events. Controls used for monitoring extremity dose and the placement of dosimetry when work involved significant dose gradients were reviewed.

Radiation Protection program activities were evaluated against 10 CFR Part 20; TS Sections 6.11, “Radiation Protection Program,” and 6.12, “High Radiation Areas;” Regulatory Guide 8.38, “Control of Access to High and Very High Radiation Areas in Nuclear Power Plants;” and approved licensee procedures. Licensee guidance documents, records, and data reviewed are listed in the report Attachment.

Problem Identification and Resolution. Five CERs and one audit associated with radiological controls, personnel monitoring, and exposure assessments were reviewed and discussed with Radiation Protection supervisors. The inspectors assessed the licensee’s ability to identify, characterize, prioritize, and resolve the identified issues in accordance with licensee SAP-1131, “Corrective Action Program.” Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls

a. Inspection Scope

As Low As Is Reasonably Achievable (ALARA). Implementation of the licensee's ALARA program during RF-15 was observed and evaluated by the inspectors. The inspectors reviewed ALARA planning, dose estimates, and prescribed ALARA controls for outage work tasks expected to incur the maximum collective exposures. Reviewed activities included removal of SG manways and diaphragms, installation of SG nozzle dams, work on the B-Loop Reactor Coolant Pump (RCP) main flange, and installation of ex-core neutron dosimeters. Incorporation of planning, established work controls, expected dose rates, and dose expenditure into the ALARA pre-job briefings and RWPs for those activities were also reviewed. The inspectors directly observed performance of the steam generator nozzle dam installation while evaluating the licensee’s use of engineering controls, low-dose waiting areas, and on-the-job supervision.

Selected elements of the licensee's source term reduction and control program were examined to evaluate the effectiveness of the program in supporting implementation of the ALARA program goals. Shutdown chemistry program implementation and the resultant effect on Containment and Auxiliary Building dose rate trending data were reviewed and discussed with cognizant licensee representatives.

Trends in individual and collective personnel exposures at the facility were reviewed. Records of year-to-date individual radiation exposures sorted by work groups were examined for significant variations of exposures among workers. The inspectors examined the dose records of all declared pregnant workers during 2003 and 2004 to evaluate total or current gestation dose. Applicable procedures were reviewed to assess licensee controls for declared pregnant workers. Trends in the plant's three-year rolling average collective exposure history, outage, non-outage and total annual doses for selected years were reviewed and discussed with licensee representatives.

The licensee's ALARA program implementation and practices were evaluated for consistency with FSAR Chapter 12, "Radiation Protection;" 10 CFR Part 20 requirements; Regulatory Guide 8.29, "Instruction Concerning Risks from Occupational Radiation Exposure," February 1996; and licensee procedures. Documents reviewed during the inspection of this program area are listed in Section 2OS2 of the report Attachment.

Problem Identification and Resolution. The inspectors reviewed the corrective action program documents listed in Section 2OS2 of the report Attachment that were related to the licensee's ALARA program. The inspectors assessed the licensee's ability to identify, characterize, prioritize, and resolve the identified issues in accordance with SAP-1131, "Corrective Action Program."

b. Findings

No findings of significance were identified.

2PS2 Radioactive Material Processing and Transportation

a. Inspection Scope

Waste Processing and Characterization. The inspectors reviewed the plant's solid radioactive waste system as described in the FSAR and the process control program. The most recent radiological effluent release report was reviewed for information on the types and amounts of waste disposed. The scope of the licensee's audit program was reviewed to verify that it met the requirements of 10 CFR 20.1101(c). The inspectors walked down the accessible portions of the liquid and solid radioactive waste processing systems to verify that the current system configuration and operation agreed with the FSAR and the process control program. The liquid radioactive waste evaporator lay-up status was discussed with radwaste and operations personnel to determine its potential to create an unmonitored release pathway.

The inspectors reviewed the radiological operating report for any documented changes to the radwaste processing systems and discussed observations with radwaste personnel. The inspectors reviewed the plant's process for transferring radioactive resin and sludge discharges into shipping/disposal containers to determine if appropriate waste stream mixing and/or sampling procedures and methodology for waste concentration averaging provided representative samples of the waste product for waste classification purposes. The inspectors reviewed current 10 CFR 61 analysis results and the procedures for obtaining the samples to support the analysis. The scaling factors used for radioactive waste streams were reviewed, including licensee calculations used to determine the amount of hard to detect nuclides. The program was reviewed to verify compliance with 10 CFR 61.55-56 and Appendix G of 10 CFR 20.

The inspectors reviewed the program for provisions that would ensure that the waste stream composition accounted for changes in operational parameters and would remain valid between required periodic updates.

Transportation. The inspectors observed the receipt of a laundry shipment from a vendor facility and a return shipment of laundry to the vendor using the same truck. The observations included licensee radiation surveys, labeling, placarding, vehicle checks, driver's briefing and emergency instructions, a review of shipping papers provided to the driver, and licensee final verification of shipment readiness. The inspectors observed the preparation and shipment of a radiography source which was a Type B shipment. The inspectors reviewed shipping documentation for several shipments that had occurred in the previous year. The inspectors reviewed the Quality Assurance (QA) surveillance documentation verifying compliance with the Certificate of Compliance (CoC) for the Type B package.

The inspectors reviewed the training records of the radwaste workers who were involved in the shipment and discussed training with these workers.

Transportation program implementation was reviewed against regulations detailed in 10 CFR Part 20, 10 CFR Part 71, 49 CFR Parts 172-178; as well as the guidance provided in NUREG-1608. Technical Specification 6.13, "Process Control Program was," used as a basis for evaluation of the solid radioactive waste program. Training activities were assessed against 49 CFR Part 172 Subpart H. Documents reviewed during the inspection are listed in Section 2PS2 of the report Attachment.

Problem Identification and Resolution. Four CERs, one self assessment and one QA audit were reviewed in detail and discussed with licensee personnel. The inspectors assessed the licensee's ability to characterize, prioritize, and resolve the identified issues in accordance with licensee procedure SAP-1131, "Corrective Action Program." Documents reviewed for problem identification and resolution are listed in Section 2PS2 of the report Attachment.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification

a. Inspection Scope

The inspectors sampled licensee records to verify the accuracy of reported Performance Indicator (PI) data for the periods listed below. To verify the accuracy of the reported PI elements, the reviewed data were assessed against guidance contained in Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Indicator Guideline," Rev. 3, and the PI Frequently Asked Questions (FAQ) list.

Occupational Radiation Safety Cornerstone. The inspectors reviewed the Occupational Exposure Control Effectiveness PI results for the period of January 2004 through March 2005. For the assessment period, the inspectors reviewed HP shift log entries, electronic dosimeter alarm logs, and licensee procedural guidance for collecting and documenting PI data. CERs were reviewed for uptakes and abnormal TLD results. Section 2OS1 contains additional details regarding the inspection of controls for exposure significant areas and review of related CERs. Documents reviewed are listed in sections 2OS1 and 4OA1 of the report Attachment.

Public Radiation Safety Cornerstone. The inspectors reviewed the Radiological Control Effluent Release Occurrences PI results for the period of January 2004 through March 2005. For the assessment period, the inspectors reviewed cumulative and projected doses to the public. The inspectors also reviewed licensee procedural guidance for collecting and documenting PI data. Documents reviewed are listed in section 4OA1 of the report Attachment.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

.1 Daily Screening of Corrective Action Items

a. Inspection Scope

As required by Inspection Procedure 71152, “Identification and Resolution of Problems,” and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee’s corrective action program. This review was accomplished by either attending daily screening meetings that briefly discussed major CERs, or accessing the licensee’s computerized corrective action database and reviewing each CER that was initiated.

b. Findings

No findings of significance were identified.

.2 Annual Sample Review

a. Inspection Scope

The inspectors reviewed one issue in detail to evaluate the effectiveness of the licensee's corrective actions for important safety issues documented in CER 0-C-05-0708. This CER was associated with "B" charging pump breaker charging springs failed to charge when racked into the operate position. The inspectors assessed whether the issue was identified in a timely manner; documented accurately and completely; properly classified and prioritized; adequately considered extent of condition, generic implications, common cause, and previous occurrences; adequately identified root causes/apparent causes; and, identified appropriate corrective actions. Also, the inspectors verified the issue was processed in accordance with SAP-1131, "Corrective Action Program."

b. Findings

No findings of significance were identified; however, the inspectors identified that the licensee's corrective actions for the CER was not thorough. Specifically, the CER did not address revising existing General Electric Magne Blast 7.2 kV refurbishment procedures to include key corrective actions identified in the body of the apparent cause evaluation. The charging spring motor had failed to energize due to mechanical interference between the breaker's closing latch and the switch cam. Two set screws, one on top of the other, for redundant positive latch to shaft engagement, were found to be loose and had allowed the interference. The apparent cause evaluation for the CER stated that future 7.2 kV Magne Blast breaker overhauls performed on-site would replace rather than reuse the set screws to address the generic vulnerability. However, the plans to revise existing breaker refurbishment procedures were not entered into the corrective action program as intended and the subject CER was closed out. When questioned by the inspectors, the licensee re-opened the CER and added a corrective action to revise the existing refurbishment procedures.

.3 Semi-Annual Trend Review

a. Inspection Scope

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," the inspectors performed a review of the licensee's corrective action program and associated documents to identify trends that could indicate the existence of a more significant safety issue. The review was focused on repetitive equipment issues, but also considered trends in human performance errors, the results of daily inspector corrective action item screening discussed in Section 4OA2.1 above, licensee trending efforts, and licensee human performance results. The review nominally considered the six-month period of January 2005 through June 2005. Documents reviewed included licensee monthly corrective action trending reports, engineering system health reports, department self-assessment activities, and quality assurance audit reports.

b. Findings

No findings of significance were identified. However, the inspectors observed that there was an increase in the number of mis-positioning events that occurred in the operations area during the refueling outage due mainly to human performance errors and procedure quality problems. These events are discussed in more detail in Sections 1R14,1R20, and 4OA7 of this report. The inspectors noted that after discussing the increasing trend with the licensee, CER 0-C-05-2620 was initiated in order to conduct a common cause evaluation associated with several of the more significant issues.

4OA4 Cross-Cutting Aspects of Findings

Section 1R08 describes a finding involving the application of an inadequate on-line leak repair procedure, which resulted in a FAC induced failure of a 1" diameter Main Steam Turbine Casing Drain / 3rd Stage Extraction Steam Equalization Line. The failure could have been reasonably prevented when the original pin-hole leak was discovered on a line that was thought to be a resistant material and not have any flow through it. The licensee had an opportunity to evaluate the "as-installed" configuration, the active corrosion mechanism (FAC), and the incorrect design drawings upon discovery of the initial pin-hole leak. This opportunity was an evaluation issue of the cross-cutting aspect of Problem Identification and Resolution.

Section 1R14 describes a self-revealing NCV for operations and electrical maintenance personnel failure to adequately review and understand the impact on the plant of protective relay work activities that resulted in a loss of power event. The review problem was an organizational issue of the cross-cutting aspect of Human Performance.

Section 1R20 describes an NRC-identified NCV for an operator failure to follow startup and system operating procedures for placing the RHR system in its proper alignment to support plant heatup. The failure to follow procedures was an attention issue of the cross-cutting aspect of Human Performance.

4OA5 Other

.1 (Closed) NRC Temporary Instruction (TI) 2515/160: Pressurizer Penetration Nozzles and Steam Space Piping Connections in U.S. Pressurized Water Reactors (NRC Bulletin 2004-01)

The inspectors reviewed the licensee's final response to NRC Bulletin 2004-01, dated November 16, 2004. The inspectors verified that the licensee's inspection activities conducted during this outage were consistent with their response.

The inspectors conducted an independent observation of the licensee's inspections of the susceptible welds on the top of the pressurizer to ensure that the physical conditions of the pressurizer penetrations and welds were adequately inspected, and that there were no problems with debris, insulation, dirt, boron from other sources, physical layout, or viewing obstructions, which could have interfered with the identification of boric acid leakage. Specifically, the inspectors observed inspection of three safety valve nozzles, the common relief valve nozzle, and the spray line. In addition, the inspectors reviewed documentation of the pressurizer surge line weld inspection (although this line was not in scope of the bulletin).

Reporting Requirements are as follows:

a. For each of the examination methods used during the outage, was the examination:

1. Performed by qualified and knowledgeable personnel?

   Yes. The licensee used a knowledgeable staff member certified as Level II, VT-2 examiners in accordance with the Nuclear Training Manual, Appendix VI, Quality Systems Training Program, Rev. 3 to conduct a direct visual examination of the bare metal surface of the above components. This qualification and certification procedure referenced the industry standard ANSI/ANST CP-189, "Standard for Qualification and Certification of Nondestructive Testing Personnel."

2. Performed in accordance with demonstrated procedures?

   Yes. The inspectors observed the licensee performing the bare metal inspection of the pressurizer penetrations in accordance with procedures SAP-1100, "Boric Acid Corrosion Control Program," Rev. 1, and QSP-216, "Boric Acid Corrosion Inspection," Rev. 0.

3. Able to identify, disposition, and resolve deficiencies?

   Yes. The inspectors concluded that the licensee's direct visual examinations were capable of detecting leakage from cracking in pressurizer penetrations if it had existed. This conclusion was based upon the inspectors direct observations of pressurizer penetration locations, which were free of debris or deposits that could mask evidence of leakage in the areas examined. The inspectors also verified that the licensee's procedures included guidance for proper disposition and investigation of any identified deficiencies.

4. Capable of identifying the leakage in pressurizer penetration nozzle or steam space piping components, as discussed in NRC Bulletin 2004-01?

The inspectors verified that the licensee's examination personnel were capable of identifying any leakage in pressurizer penetration nozzles.

b. What was the physical condition of the penetration nozzle and steam space piping components in the pressurizer system?

Through observations of licensee personnel, the inspectors verified that the metal reflective insulation had been removed with caution so as not to disrupt any potential indications of boric acid leakage from the pressurizer at these penetration locations. The licensee personnel performed a direct visual inspection of these pressurizer penetrations. Based on this examination, the area examined was generally clean and free of debris or deposits or other obstructions which could mask evidence of leakage. However, some white residue was noted on safety nozzle 12. The licensee believed the substance was not boric acid but appropriately wrote CER 0-C-05-1476 to document the condition and chemically checked the material for radioactive isotopes. The inspectors reviewed the test results which showed that no radioactive isotopes were present indicating that the material was not boric acid.

c. How was the visual inspection conducted?

The licensee's inspection personnel used the direct visual examination technique along with a handheld mirror.

d. How complete was the coverage?

The licensee was able to view the entire circumference, 360°, around each penetration.

e. Could small boron deposits, as described in the Bulletin 2004-01, be identified and characterized?

The examination personnel were appropriately trained and qualified to identify small boron deposits as described in the bulletin.

f. What material deficiencies (i.e., cracks, corrosion, etc.) were identified that required repair?

There were no deficiencies identified that required repair.

g. What, if any, impediments to effective examinations, for each of the applied methods, were identified?

There were no impediments for an effective examination.

h. If volumetric or surface examination techniques were used for the augmented inspections, what process did the licensee use to evaluate and dispose any indications that may have been detected as a result of the examinations?

Not Applicable. No augmented surface or volumetric examinations were performed. In accordance with the licensee's response, only a bare metal visual examination was conducted this outage, and there were no indications identified that required further examination.

I. Did the licensee perform appropriate follow-up examinations for indications of boric acid leaks from pressure-retaining components in the pressurizer system?

Not Applicable. There were no indications of boric acid leaks from susceptible pressure-retaining components.

.2 (Closed) NRC TI 2515/161: Transportation of Reactor Control Rod Drives In Type A Packages

This TI was issued to address use of a Type A shipping container to ship control rod drives in a way that was inconsistent with its CoC. Inspectors reviewed shipping logs and questioned licensee personnel about the shipment of control rod drives and determined that none had been shipped since January 1, 2002.

.3 (Closed) NRC TI 2515/163: Operational Readiness of Offsite Power

The inspectors reviewed licensee procedures and controls and interviewed operations, engineering, and maintenance personnel to verify these documents contained specific attributes delineated in the TI to meet operational readiness of offsite power systems in accordance with 10 CFR 50, Appendix A, General Design Criterion 17, "Electric Power Systems," plant TS for offsite power systems; 10 CFR 50.63, "Loss of All Alternating Current Power;" and 10 CFR 50.65(a)(4), "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Documents reviewed are listed in the Attachment. Appropriate documentation of the results of this inspection was provided to NRC headquarters staff for further analysis, as required by the TI. This completes the Region II inspection TI requirements for the Virgil C. Summer Nuclear Station.

.4 Institute of Nuclear Power Operations (INPO) Biennial Plant Evaluation - Interim Report Review

The inspectors reviewed the interim report of the INPO biennial evaluation of site activities conducted February - March 2005. The inspectors reviewed the report to ensure that issues identified were consistent with the NRC perspectives of licensee performance and if any significant safety issues were identified that needed further NRC followup. No findings of significance were identified.

4OA6 Meetings, Including Exit

Exit Meeting Summary

The inspectors presented the inspection results to Mr. Jeff Archie and other members of the licensee staff on July 13, 2005. The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

4OA7 Licensee-Identified Violations

The following findings of very low safety significance (Green) were identified by the licensee and are violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as NCVs.

- 10 CFR 20.1906 requires that the licensee perform a radiation survey of radioactive material packages received unless the package contains less than or equal to the Type A quantity. This survey is to be performed as soon as practical after receipt of the package, but not later than 3 hours after the package is received during the licensee's normal working hours, and not later than 3 hours from the beginning of the next working day if it is received after working hours. On June 24, 2004, at 12:40 p.m., a 133 curie radiography source in excess of Type A Quantities was received at the licensee's warehouse. On June 25, 2004, at 9:20 a.m., the package receipt surveys were performed. The survey was performed 19 hours and 35 minutes after receipt. The package was intact with no indications of degradation. The survey determined that there was no removable contamination and dose rates were at expected levels. This violation is of very low safety significance because the package was intact with no loss of contents, did not exceed regulatory limits upon survey, and therefore did not constitute a significant potential for exposure to members of the public. This issue was entered into the licensee's CAP as CER 0-C-04-2020.

- TS 6.8.1.a requires, in part, that written procedures be established, implemented and maintained covering activities listed in Regulatory Guide 1.33, Rev. 2, Appendix A, February 1978, which includes procedures for operation of the onsite and offsite electrical systems (Section 3.s). Licensee system operating procedure SOP-304, "7.2 kV Switchgear," Rev. 10, was written to provide instructions for operation of the Class 1E 7.2 kV electrical distribution system. Section IV.C of the procedure for placing the Class 1E vital bus 1DB on its alternate feed, requires the System Dispatcher be informed of new low voltage limits to maintain the Parr 115 kV offsite circuit while supplying both vital buses 1DB and 1DA. Contrary to the requirements of SOP-304, on May 21, 2005, operators failed to contact the System Dispatcher when vital bus 1DB was placed on its alternate feed. This resulted in the Parr 115 kV line voltage dropping below its TS 3.8.12 low voltage operability limit between May 21-23. This violation is of very low safety significance because the licensee determined that, considering the available loads that would have started on the corresponding safeguards buses, the voltage would not have dropped below that necessary for proper operation of safeguards equipment during a design basis event. This issue was entered into the licensee's CAP as CER 0-C-05-2178.

- TS 6.8.1.a requires, in part, that written procedures be established, implemented and maintained covering activities listed in Regulatory Guide 1.33, Rev. 2, Appendix A, February 1978, which includes procedures for plant startup (Section 2.a). Licensee general operating procedure GOP-2, "Plant Startup and Heatup (Mode 5 to Mode 3)," Rev. 13, was written to accomplish plant startup from Cold Shutdown (Mode 5) to hot Standby (Mode 3). Prior to entering Mode 3, Step 3.9 of the procedure directed startup and verification of the operational readiness of the feedwater system in accordance with system operating procedure SOP-210, "Feedwater System," Rev. 18. Contrary to the requirements of GOP-2, on May 27, 2005, the Control Room Supervisor signed off Step 3.9 indicating that the feedwater system was in a condition to support operation, when the system had not been fully filled and vented in accordance with applicable sections of SOP-210. Subsequently, the unit entered Mode 3 on May 28, 2005, and when feedwater system filling and venting was resumed that same day, all three feedwater isolation valves (FWIVs) were opened at one time in accordance with SOP-210. This rendered all three FWIVs inoperable as a result of the accumulator air pressure to each valve's actuator dropping below the 500 psig setpoint for operability. Since TS 3.7.1.6 only allows one FWIV to be inoperable in Mode 3, the operators entered TS 3.0.3, and subsequently reclosed all three FWIVs within seven minutes. This violation is of very low safety significance because the feedwater system was not inservice at the time of the event and due to the short duration that all three FWIVs were inoperable. This issue was entered into the licensee's CAP as CER 0-C-05-2298.

- TS 3.0.4 requires, in part, that entry into an Operational Mode or other specified condition shall not be made unless the conditions of the Limiting Condition for Operation are met without reliance on provisions contained in the action requirements. Contrary to the requirements of TS 3.0.4, on May 28, 2005, an Operational Mode change from Mode 4 to Mode 3 occurred without meeting the limiting condition for operation of TS 3.7.1.2 which states, in part, that at least three independent steam generator emergency feedwater pumps and flow paths shall be operable in Modes 1, 2, and 3. The TDEFW pump was inoperable due to outage maintenance and the "A" MDEFW pump switch on the Main Control Board was inadvertently left in the PTL position rendering it inoperable during the escalation to Mode 3. This violation is of very low safety significance because the "A" MDEFW pump was quickly returned to service by placing the control switch in the "normal after stop" position, and the "B" MDEFW pump remained operable during the period that the opposite pump was in PTL. This issue was entered into the licensee's CAP as CER 0-C-05-2300.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

J. Archie, Vice President, Nuclear Operations
F. Bacon, Manager, Chemistry Services
L. Blue, Manager, Health Physics Services
M. Browne, Manager, Quality Systems
R. Clary, Manager, Nuclear Licensing
M. Findlay, Manager, Nuclear Protection Services
M. Fowlkes, General Manager, Engineering Services
T. Franchuk, Supervisor, Quality Assurance
S. Furstenberg, Manager, Nuclear Operations Training
D. Gatlin, General Manager, Nuclear Plant Operations
D. Lavigne, General Manager, Organization Effectiveness
G. Lippard, Manager, Operations
J. Nesbitt, Manager, Materials and Procurement
K. Nettles, General Manager, Nuclear Support Services
W. Stuart, Manager, Plant Support Engineering
R. Sweet, Supervisor, Nuclear Licensing
A. Torres, Manager, Planning / Scheduling and Project Management
S. Zarandi, Manager, Maintenance Services

ITEMS OPENED AND CLOSED

Opened and Closed

05000395/2005003-01	FIN	Failure of 1" Extraction Steam Line Due to Inadequate On-Line Leak Repair Procedure (Section 1R08)
05000395/2005003-02	NCV	Failure to Adequately Review and Understand the Impact of Relay Maintenance Resulting in Loss of “B” Train Safegurads Bus and Automatic Start of “B” EDG and ESF Loading Sequencer (Section 1R14)
05000395/2005003-03	NCV	Failure to Follow Startup Procedure for Aligning RHR System During Plant Heatup (Section 1R20)

Closed

2515/160	TI	Pressurizer Penetration Nozzles and Steam Space Piping Connections in U.S. Pressurized Water Reactors (NRC Bulletin 2004-01) (Section 4OA5.1)
2515/161	TI	Transportation of Reactor Control Rod Drives In Type A Packages (Section 4OA5.2)

2515/163 TI Operational Readiness of Offsite Power (Section 4OA5.3)

LIST OF DOCUMENTS REVIEWED

<u>Section 1R04: Equipment Alignment</u>

SOP-211, "Emergency Feedwater System"
SOP-115, "Residual Heat Removal System"
SOP-117, "Service Water System"
SOP-311, "125 VDC System"
STP-501.001, "Battery Weekly Test"
Drawing E-206-005, "Plant Electrical Distribution"
MWR 0419630, corrosion on several intercell connections for XBA0004

<u>Detailed Equipment Alignment - RHR system</u>
FSAR Chapters 5 and 6
TS Sections 3.5.2, 5.3, 5.4, 3.9.7.1, 3.9.7.2
Engineering Change Request ECR-50316,"Automatic Transfer to the RB Sump"
SOP- 115, "Residual Heat Removal,"
STP-375.001, (2,3,4), "Refueling Water Storage Tank Level Instrument ILT00990-(993)," loop calibration procedures for the last two years
STP-395.054, (5, 6, 7), "Refueling Water Storage Tank Level Instrument ILT00990-(993) Operational Test," for the last two years
AB-7, "Residual Heat Removal System Description"
Design Basis Documents for ECCS and RHR
D-302-641, "Residual Heat Removal System
D-302-693, "Safety Injection System"
CER Data Base search and review of RHR system CERs from 11/2004-05/2005, (13 CERs reviewed)
Completed General and Surveillance Test Procedures reviewed - licensee completion dates
STP-230.007, RHR Pump A/B and Check Valve full flow test - 05/13/05
STP-130.004B, RHR valve Operability Test Mode 4 - 05/13/05
STP-250.019, RHR Leakage Assessment - 05/15/05
STP-205.004, RHR Pump and Valve Operability Test - 01/06/05; 01/20/05; 04/01/05; and 04/14/05; and 05/13/05

<u>Section 1R05: Fire Protection</u>

Virgil C. Summer FPP-026, Attachment 1, "Drill Planning Guide," and Attachment II, Drill Scenario Number 8;
Fire Protection Pre-Plan for Transformer Area (fire zone DG, 436' elevation); FPP-026, "Fire / Hazmat Response;"
Virgil C. Summer Nuclear Station Critique for unannounced fire drill conducted on December 12, 2004
CER 0-C-04-3686 (4th quarter 2004 fire drill critque comments)

Section 1R06: Flood Protection Measures

NRC Inspection Procedure IP-71111.06, Flood Protection Measures
FSAR (word search review for: flood), sections 1.1, 1.2, 1.7, 2.1, 2.4, 3.1, 6.0, 7.1, 9.9, 10.1
CMP-700.012, Embedded Pull Box Inspection
CMP-700.013, Inspection of Electrical Manholes
SAP-131, Fire Protection Program, Rev. 6
Recent CERs (2005 potential internal flood related CERs):
0-C-05-2255, NRC Information Notice 2005-11: Internal flooding/spray down of safety related equipment
Old CERs: 0-C-02-1329; 0-C-03-4007; and 0-C-04-0773; -2866; -2856; -1961

Section 1R08: Inservice Inspection Activities

Nondestructive Examination
GTP-304 Inservice Inspection System Pressure Testing, Third Ten Year Interval, Rev. 11
SAP-1100, Boric Acid Corrosion Control Program, Rev. 1
QSP-216, Boric Acid Corrosion Inspection, Rev. 0
Nuclear Training Manual, Appendix VI, Quality Systems Training Program Rev. 3
PTP-151.001A, Inspection of RCS for Boric Acid Corrosion
MMP-105.005, On-Line Sealant Repairs, Rev. 4

Corrective Action Documents (Problem Investigation Process [PIP])
CER 0-C-03-3711, Deficient areas of the moisture barrier identified
CER 0-C-03-3715, Semi-circular cracking of coating in dome area
CER 0-C-04-3041, Documentation of test participants not always provided
CER 0-C-04-3069, Qualifications of IST engineer indeterminate
CER 0-C-04-3105, ISI procedures need updating
CER 0-C-04-3125, A CER was not issued to track vendor identified problems
CER 0-C-04-3126, Untimely update of procedures
CER 0-C-04-3127, Quality control inspector re-certified to outdated program
CER 0-C-04-2796, OE, NRC IN 2004-17, Loose Part Detection and Computerized ECT Analysis
CER 0-C-03-1429, Boric Acid Corrosion Program self assessment action items
CER 0-C-04-1380, Steam Leak on Extraction Line under HP Turbine, identified 5/04
CER 0-C-04-3775, Steam leak on Extraction Line under HP Turbine, identified 12/04

Self-Assessments and Audits
Audit QA-AUD-200410-0, IST/ISI Audit dated 09/07/2004
SA03-SE-01, Boric Acid Corrosion Program Self-Assessment Report, March 31-April 3, 2003
RCA 04-3775, Root Cause Analysis Report for FAC pipe rupture

Steam Generator
SGMP-100.005, Steam Generator IN-SITU Pressure Test Selection Guideline, Rev. 0
Condition Monitoring and Operational Assessments for VC Summer, January 3, 2001
Steam Generator Management Program Strategic Plan, October 2002
51-5007713-03, VC Summer Steam Generator Degradation Assessment, 3/30/2004

51-5058316-00, VC Summer Unit 1 Steam Generator Eddy Current Analyst Guidelines
51-5058315-00, VC Site-Validated Eddy Current Techniques for VC Summer Unit 1

Other Documents
Boric Acid Corrosion Health Report, 4th quarter 2004

Section 2OS1: Access Control To Radiologically Significant Areas

Procedures, Guidance Documents, and Manuals
Health Physics Procedure (HPP)-151, Use of the Radiation Work Permit and Standing Radiation Work Permit, Rev. (Rev.) 8
HPP-152, Radiation Control Area Access Control, Rev. 9
HPP-154, Issuance And Control Of Respiratory Protection Equipment, Rev. 12
HPP-155, Control Of Airborne Radiation Exposure (DAC-HRS), Rev. 11
HPP-158, Contamination Control For Equipment And Materials, Rev. 13
HPP-160, Control and Posting of Radiation Control Zones,Rev. 10
HPP-302, Radiation And Contamination Survey Techniques, Rev. 9
HPP-303, Airborne Activity Sampling Techniques, Rev. 7
HPP-401 Issuance, Termination and Use of RWPs and SRWPs, Rev. 16
HPP-402, Radiological Survey Requirements and Controls for Reactor Building and Incore Pit Entries, Rev. 10
HPP-403, Radiological Controls For Nuclear Work Activities, Rev. 9
HPP-413, Diving Operations, Rev. 2
HPP-419, Electronic Dosimeter Alarm Setpoint Determination and Alarm Response Action, Rev. 0
HPP-515, Interpretation Of Bioassay Analyses, Rev. 12
Station Administrative Procedure (SAP)-500, Health Physics Manual, Rev. 11

Radiation Work Permits (RWPs)
04-00011, RHR Venting, Valve Line-up, and Surveillance, 7/13/2004
04-00012, All Manual/ Remote Filter Change Outs for 2004, 1/28/2004
04-00211, Clean Boron and VT Various Components, 6/2/2004
04-00235, Reactor Building Entry To Check and Perform Vibration Tests on All Compartment Fans, 12/6/2004
04-00236, Reactor Building Entry to Perform Visual Inspection of “B” RCP Flange From RB463, 12/6/2004
04-00237, Reactor Building Entry to Replace DRPI Card RB 436, 12/6/2004
04-00238, Reactor Building Entry to Calibrate IYS09329A Loop “C” Fan “A” Vibration Switch, 12/6/2004

Corrective Action Program Documents
CER 0-C-03-3583, Individual received uptake of radioactive material
CER 0-C-03-3629, AB526-06 “A” Spent Fuel Purification Filter Cubicle was found to be improperly posted as a result of changing conditions.
CER 0-C-03-3798, Poor job planning resulted in excessive time in locked high rad area.
CER 0-C-03-4309, Individual received ED dose rate alarm while climbing in the overhead of the AB 412 west penetration room to remove RHR vent rig.

CER 0-C-04-0258, Individual entered a posted High Radiation Area to perform work wearing his TLD but without his E.D. (Electronic Dosimeter)
CER 0-C-04-1722, ED dose rate alarm received while assisting a co-worker covering up rad Material in the rad waste yard.
CER 0-C-03-4162, Unexpected dose rate alarm
CER 0-C-05-0217, AB 436-06 found contaminated during the weekly routine survey.
CER 0-C-05-0359, Contract Employee alarming PM at RCA due to radioactive medical injection. The Doctor had told individual that he would not have any problem with access.
CER 0-C-05-0394, TLD worn by worker after having medical stress test performed.
CER 0-C-05-0368, Worker received an Electronic Dosimeter dose rate alarm while performing job planning in the RCA. Rate alarm was set at 50 mrem/hr, in the process of hanging a tag the worker entered an area of 53 mrem/hr which caused a momentary alarm.
CER 0-C-1636, HPT discovered higher than anticipated radiological conditions in the RB Transfer Canal when performing a pre-dive survey. The diving was not performed.
QA-AUD-200502-0, "Station Radiation Control" Audit, 3/29/2005

Section 2OS2: ALARA Planning and Controls

Procedures, Instructions, Guidance Documents, and Operating Manuals
VC Summer Nuclear Station (VCSNS) RF-15 Alara Plan Issued 3/22/2005
SCE&G Corporate ALARA Plan, Rev. 11, 12/01/2003
HP Technical Work Record 00-22, "Correction factor for Outage Estimate," 2/01/2000
HPP 150, Requirement for Issuance and Use fo Personnel Dosimetry, Rev. 8, 6/05/2003
HPP-151, Use of the Radiation Work Permit and Standing Radiation Work Permit, Rev. 8, 10/18/2004
HPP-401, Issuance, Termination, and Use of RWPs and SRWPs, Rev. 17, 3/07/2005
HPP-419, Electronic Dosimeter Alarm Set Point Determination and Alarm Response Actions, Rev. 0, 3/22/2005
HPP-505, Issuance and Termination of Personnel Dosimetry, Rev. 16, 09/25/2003
HPP-604, Setup of airline Respiratory Equipment, Rev. 9, 4/20/2005
HPP-819, Temporary Shielding Evaluation, Installation, and Removal, Rev. 11, 2/18/2005
SAP 121, ALARA Committee, Rev. 9, 6/20/2003
ALARA Estimate Basis Work Up for RWP 05-0077, "B" RCP main flange gasket replacement
ALARA Estimate Basis Work Up for RWP 05-0078, Install Ex Vessel Neutron Dosimetry in the Incore Pit
ALARA Estimate Basis Work Up for RWP 05-0079, Install Ex Vessel Neutron Dosimetry in Reactor Cavity
ALARA Estimate Basis Work Up for RWP 05-0084, Install/remove nozzle dams in "A" "B" & "C" SGs
ALARA Estimate Basis Work Up for RWP 05-0085, Install/remove Primary manways "A" "B" & "C" SGs
ALARA Estimate Basis Work Up for RWP 05-0089, Setup/tear down eddy current testing equipment for SGs

Records and Data
Dose Records of all declared pregnant workers (2) during the period 01/01/2003 to 05/04/2005

ALARA In-Progress Review for RWP 03-045, dated 11/09/2003
ALARA In-Progress Review for RWP 03-080, dated 10/26/2003
ALARA Post-Job Review for RWP 03-045, dated 11/20/2003
RWP Turnover Sheets for RWP 05-00078,79 Install Ex Vessel Neutron Dosimetry, 4/25/2005
VCSNS RF-15 Daily Exposure Reports, 4/27 - 5/05/2005
Temporary Shielding Request Package # 05-019, Install Date 4/25/2005
Temporary Shielding Request Package # 05-001, Install Date 4/25/2005
Computerized Exposure Nuclear Tracking System (CENTS) printout of current TEDE exposure for Health Physics and Mechanical Maintenance Work Groups, 5/03/2005
Quarterly ALARA Committee Meeting Minutes dated 12/10/2003, 3/18/2004, 6/23/2004, 9/28/2004, 12/02/2004
RWP 05-0077, “B” RCP main flange gasket replacement
RWP 05-0078, Install Ex Vessel Neutron Dosimetry in the Incore Pit
RWP 05-0079, Install Ex Vessel Neutron Dosimetry in Reactor Cavity
RWP 05-0084, Install/remove nozzle dams in “A” “B” & “C” SGs
RWP 05-0085, Install/remove Primary manways “A” “B” & “C” SGs
RWP 05-0089, Setup/tear down eddy current testing equipment for SGs

CAP Documents
CER 0-C-04-0104, The actual dose for RWP # 04-21 exceeded the estimated dose, 1/14/2004
CER 0-C-04-0367, RWP 04-026 “PSRST to HIC resin transfer” dose estimate was adjusted due to bent guide pin on cask lid, 2/9/2004
CER 0-C-04-0442RWP 04-00332, “Perform MOVATS of XVG08809A-SI missed RWP estimate. RWP estimated for 65 mrem; actual exposure was 105 mrem,” 2/17/2004
CER 0-C-05-1527, RWP 05-0078 Ex Core Vessel Dosimetry exceeded its exposure estimate by 77%, 4/29/2005
QA-AUD-200502-0, “Station Radiation Control” Audit, 3/29/2005
Self Assessment Report SA03-HP-04, “Health Physics Field Operations,” 3/05/2004

Section 2PS2: Radioactive Material Processing and Transportation

Procedures, Manuals, and Guides
HPP-159, General Requirements For Receipt And Shipping Of Radioactive Material, Rev. 5
HPP-702, Receipt Of Radioactive Material, Rev. 8
HPP-703, Shipping Radioactive Material, Rev. 13
HPP-712, Classification Of Radioactive Materials, Rev. 9
HPP-716.005, CNS 8-120B Cask Handling, Rev. 0
HPP-716.029, 10-160B Cask Handling, Rev. 0
HPP-717, Sample Collection, Preparation And Analysis Techniques For Assuring Compliance With 10CFR61, Rev. 6
UFSAR Chapter 11, Rad Waste Management
UFSAR Chapter 12, Radiation Protection

Shipping Records and Radwaste Data
Shipping Papers
05-05, 14-215 HIC Resin to CNSI, 1/21/05
05-07, Type B- 17 Curie Ir-192 radiography source to AEA 2/2/05

05-14, PZR safety valves to NWS
05-23, DAW to Duratek
05-25, 220 ft Sea Vans of green is clean trash to Duratek
05-33, Laundry to Unitech

Radwaste Data
Shipment Log January 2004-March 2005
10 CFR 61 analysis results for CVCS Resin, Duratek Resin, Duratek Charcoal, Filters and dry active waste DAW, 6/4/2003 through 5/4/2004
CoC, Package USA/9269/B(U)-85, Rev.3
CoC, Package USA/ 9204/B(U)-85, Rev.9
CoC, Package USA/9168/B(U), Rev.13
Rad waste Shippers Qualification List
Lesson Plan HPRPF-35, Shipment and Receipt of Radioactive Material, Rev.2

CAP Documents
QA Audit: QA-AUD-200306-0, Radioactive Waste, 7/10/03
Self Assessment Report: SA04-HP-02, Radwaste Self-Assessment, 6/21-7/1/04
CER 0-C-04-2020, Radioactive Material at WH-A was not received in accordance with 10 CFR 20 and SCDHEC Part III regulations.
CER 0-C-05-0122, Radioactive Material Shipment was received on site without a proper receipt survey.
CER 0-C-05-1633, Used Ir-192 radiography source sent to Columbia SC via Fed Ex was returned to VCS due to incomplete wording on the shipping manifest.
CER 0-C-04-3752, A calculation error was identified during the 5 year renewal of the Old Steam Generator Recycle Facility- Radioactive Material License #517. Error was conservative; the activity is a factor of 100 lower than 1994 calculation estimated.

Section 4OA1: Performance Indicator Verification

Procedures, Guidance Documents, and Manuals
HPP-242, Reporting NRC Performance Indicators, Rev. 0
Station Administrative Procedure (SAP)-1131, Corrective Action Program, Rev. 4
SAP-1167, NRC Performance Indicators, Rev. 0

Records, Data, and Drawings
Listings of Corrective Action Reports (PIP's) Covering Radiation Protection Related Corrective Action Documents for January 1, 2003 through December 6, 2004.
Monthly Performance Indicator Reports for November 2003-November 2004
CENTS Query Individual Doses > 100 mrem single entry.
Monthly radioactive waste release permit summary: Cumulative maximum individual exposure At controlling location, January 2004 - November 2004
Liquid Radioactive Release Permits , 12/2004-3/2005
Post release liquid radioactive release permit updates, 12/2004-3/2005
Gaseous Radioactive Waste Release Permits, 12/2004-3/2005
Post release Gaseous Radioactive Waste Release Permits, 12/2004-3/2005
Monthly Effluent Summaries, 1/2004-2/2005

Queries of condition reporting system for system codes HP, HPC, RM, WL, WD, WP, WX (Health Physics, Health Physics Contractor, Radiation Monitor, Waste Liquid, etc.)

Section 4OA5: Other

Station Administrative Procedure SAP-703, Control of Switchyard/Transformer Yard Activities, Rev. 1
Station Administrative Procedure SAP-208, Integrated Risk Assessment, Rev. 0
Station Administrative Procedure SAP-601, Application, Scheduling and Handling of Maintenance Activities, Rev. 12
Station Scheduling Procedure SPP-001, Planning and Scheduling On-Line Maintenance Activities, Rev. 15
Station Scheduling Procedure SPP-005, Planning and Scheduling Work Order Screening and Processing, Rev. 0
System Operating Procedure SOP-304, 7.2 kV Switchgear, Rev. 10
Annunciator Response Procedure ARP-001-XCP-638, Rev. 5
Operations Administrative Procedure OAP-100.4, Communication, Rev. 1
Operations Administrative Procedure OAP-102.1, Conduct of Operations Scheduling Unit, Rev. 5
Operations Administrative Procedure OAP-114.1, Protected Equipment Placards, Rev. 0
Operations Administrative Procedure OAP-115.1, Integrated Risk Assessment Program Data Instructions and Control, Rev. 0
Special Order 05-07, Power Changes at Dispatcher's Direction, dated April 4, 2005
System Control, Standard Operating Process SOP-700, Electric System Restoration Document, Rev. 01
System Control, Standard Operating Process SOP-701, Load Curtailment Program
System Control, Standard Operating Process SOP-104, VC Summer Work Planning Communication, Rev. 00
2001 V.C. Summer Transient Stability Study
CER 0-C-04-1218, NRC Regulatory Issue Summary 2004-05 review
CER 0-C-05-2329, NRC inspection on grid reliability concerns

LIST OF ACRONYMS

ALARA	As Low As Is Reasonably Achievable
ARP	Alarm Response Procedure
ASME	American Society of Mechanical Engineers
BACC	Boric Acid Corrosion Control
CAP	Corrective Action Program
CER	Condition Evaluation Report
CFR	Code of Federal Regulations
CoC	Certificate of Compliance
DC	Direct Current
ECCS	Emergency Core Cooling System
ECR	Engineering Change Request
EDG	Emergency Diesel Generator

EFW	Emergency Feedwater
EMP	Electrical Maintenance Procedure
EPRI	Electric Power Research Institute
ES	Engineering Services Procedure
ESF	Engineered Safety Features
ET	Eddy Current Testing
FAC	Flow Accelerated Corrosion
FAQ	Frequently Asked Questions
FIN	Finding
FPP	Fire Protection Procedure
FSAR	Final Safety Analysis Report
FWIV	Feedwater Isolation Valve
GOP	General Operating Procedure
GTP	General Test Procedure
HP	Health Physics
HPP	Health Physics Procedure
HPT	Health Physics Technician
HRA	High Radiation Area
HVAC	Heating, Ventilation, and Air-Conditioning
I&C	Instrumentation and Control
IMC	Inspection Manual Chapter
INPO	Institute of Nuclear Power Operations
ISI	Inservice Inspection
kV	kilovolt
LHRA	Locked High Radiation Area
LOCA	Loss of Coolant Accident
MDEFW	Motor Driven Emergency Feedwater
MMP	Mechanical Maintenance Procedure
MPFF	Maintenance Preventable Functional Failures
MR	Maintenance Rule
MWR	Maintenance Work Request
NCV	Non-cited Violation
NDE	Nondestructive Examination
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
OAP	Operations Administrative Procedure
OOS	Out-of-service
PI	Performance Indicator
PM	Portal Monitoring
PMT	Post-Maintenance Testing
PTL	Pull-To-Lock
QA	Quality Assurance
Rev.	Revision
Radwaste	Radioactive Waste
RB	Reactor Building
RCA	Radiologically Controlled Area
RCP	Reactor Coolant Pump

RCS	Reactor Coolant System
RF-15	Refueling Outage 15
RHR	Residual Heat Removal
RPC	Rotating Pancake Coil
RPV	Reactor Pressure Vessel
RTP	Rated Thermal Power
RWST	Refueling Water Storage Tank
RWP	Radiation Work Permit
SAP	Station Administrative Procedure
SDP	Significance Determination Process
SG	Steam Generator
SOP	System Operating Procedure
SSC	Structures, Systems and Components
STP	Surveillance Test Procedure
SW	Service Water
TDEFW	Turbine Driven Emergency Feedwater
TI	Temporary Instruction
TS	Technical Specifications
UT	Ultrasonic Testing
VT	Visual Testing