UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
2443 WARRENVILLE ROAD, SUITE 210
LISLE, IL 60532-4352

May 13, 2008

Mr. Charles Pardee
Chief Nuclear Officer
AmerGen Energy Company, LLC
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: CLINTON POWER STATION NRC INTEGRATED INSPECTION REPORT 05000461/2008002

Dear Mr. Pardee:

On March 31, 2008, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Clinton Power Station. The enclosed report documents the inspection results, which were discussed on April 11, 2008, with Mr. Mark Kanavos 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, four NRC-identified findings and one self-revealed finding of very low safety significance were identified. Four of the findings involved a violation of NRC requirements. However, because of their very low safety significance, and because the issues were entered into your corrective action program, the NRC is treating the issues as Non-Cited Violations in accordance with Section VI.A.1 of the NRC Enforcement Policy.

If you contest the subject or severity of a Non-Cited Violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the Clinton Power Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be made 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), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Mark A. Ring, Chief
Branch 1
Division of Reactor Projects

Docket No. 50-461
License No. NPF-62

Enclosure: Inspection Report No. 05000461/2008002
w/Attachment: Supplemental Information

cc w/encl: Site Vice President - Clinton Power Station
Plant Manager - Clinton Power Station
Regulatory Assurance Manager - Clinton Power Station
Chief Operating Officer and Senior Vice President
Senior Vice President - Midwest Operations
Senior Vice President - Operations Support
Vice President - Licensing and Regulatory Affairs
Director - Licensing and Regulatory Affairs
Manager Licensing - Clinton, Dresden and Quad Cities
Associate General Counsel
Document Control Desk - Licensing
Assistant Attorney General
J. Klinger, State Liaison Officer
Illinois Emergency Management Agency
Chairman, Illinois Commerce Commission
Illinois Emergency Management Agency

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Letter to C. Pardee from M. Ring dated May 13, 2008

SUBJECT: CLINTON POWER STATION NRC INTEGRATED INSPECTION REPORT 05000461/2008002

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-461
License No:	NPF-62
Report No:	05000461/2008-002
Licensee:	AmerGen Energy Company, LLC
Facility:	Clinton Power Station
Location:	Clinton, IL
Dates:	January 1 through March 31, 2008
Inspectors:	B. Dickson, Senior Resident Inspector D. Tharp, Resident Inspector Mark Mitchell, Region III Health Physicist John Cassidy, Region III Health Physicist D. Jones, Reactor Inspector V. Meghani, Region III Reactor Inspector J. Neurauter, Region III Senior Reactor Inspector R. Jicking, Senior Emergency Preparedness Analyst R. Russell, Emergency Preparedness Analyst S. Mischke, Resident Engineer, Illinois Emergency Management Agency
Approved by:	Mark Ring, Chief Branch 1 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000461/2008002; 01/01 – 03/31/08; Clinton Power Station; Fire Protection, Post-Maintenance Testing, Refueling Outage, Access to Radiological Areas, and Identification and Resolution of Problems.

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. The inspectors identified four Green findings and one finding was self-revealed. Four findings were considered Non-Cited Violations (NCVs) of NRC regulations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (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 4, dated December 2006.

A. Inspector-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. The inspectors identified a performance deficiency involving a NCV of Clinton Power Station Operating License NPF-62, Section 2.F for failure to implement the fire protection program in accordance with program requirements. The inspectors identified multiple instances of the licensee's failure to follow approved fire protection program procedures concerning control of transient combustible material. Corrective actions for this issue included removing the unattended combustible material, initiating transient combustible permits, and/or initiating compensatory measures.

  The inspectors determined that this issue was more than minor because the identified transient combustibles were in a combustible free zone required for separation of redundant trains. This finding was of very low safety significance because the transient combustible materials identified by the inspectors were not combustibles of significance. The inspectors determined that this finding was cross-cutting in the area of Problem Identification and Resolution. Specifically, the licensee implements a corrective action program with a low threshold for identifying issues. The licensee identifies such issues completely, accurately, and in a timely manner commensurate with their safety significance (P.1(a)). (Section 1R05)

- Green. A finding of very low safety significance was self-revealed by the automatic runback of the turbine driven reactor feed pump during post-outage power ascension. The licensee discovered that the wrong component was installed in the B turbine driven reactor feed pump oil pressure sensing logic. The inspectors determined that the licensee failed to perform an adequate post-maintenance test in accordance with procedures. This issue resulted in an unexpected power change from 54 percent power to 46 percent power. The licensee entered the issue into the corrective action program, performed tailgate discussions with technicians and work planners on the oil pressure switch configurations, and ensured that vendor purchase specifications for pressure switches were up-to-date in the materials and work management computer system.

  The inspectors determined this issue was more than minor because it was associated with the Human Performance attribute of the Initiating Events Cornerstone and affected the cornerstone objective of limiting the frequency of those events that upset plant stability. Specifically, the failure to perform adequate post-maintenance testing of pressure switch 1PS-FW135 permitted the wrong component to be installed and placed in service. This deficiency ultimately resulted in an unplanned plant transient. The finding was of very low safety significance because this issue did not increase the likelihood that mitigation equipment or functions would not be available. The inspectors also concluded that the failure of the technician to properly follow calibration procedure 8801.01 during the initial calibration of this switch represented a cross-cutting issue in the area of Human Performance, Work Practices (H.4(b)), because licensee personnel failed to follow procedures in regard to pressure switch calibration. (Section 1R19)

- Green. The inspectors identified a finding and an associated NCV of 10 CFR Part 50, Appendix B, Criteria V, "Instructions, Procedures, and Drawings," having very low safety significance during drywell closeout inspections. Specifically, during the performance of the NRC final drywell closeout, the inspectors noted that foreign material/housekeeping socks had not been removed from the drywell floor drains. This issue could have resulted in the drywell leak detection system being inoperable following a reactor event. The licensee procedures for drywell closeout directed licensee staff to remove all loose material and devices associated with the licensee material condition and housekeeping program. The licensee's corrective actions for this issue included removing the floor drain socks and incorporating a work activities item for sock removal in the outage schedule template.

  The inspectors determined that this issue was more than minor because, if left uncorrected, it could result in a more significant safety concern. Failure to remove drain socks from drywell floor drains could result in the inability to readily detect and track unidentified leakage following a reactor event. The finding was of very low safety significance because this finding did not result in exceeding the Technical Specification limit for reactor coolant system (RCS) leakage nor did it affect other mitigating systems resulting in a total loss of their safety function. The inspectors also concluded that this issue was a result of no work item in the outage schedule to remove the socks, and therefore represented a cross-cutting issue in the area of Human Performance, Work Control (H.3.(b)). (Section 1R20)

Cornerstone: Barrier Integrity

- Green. The inspectors identified a finding and an associated NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions," having very low safety significance, in that, in evaluating whether the reactor recirculation flow control valve "A" hydraulic power unit (HPU) piping was adequately supported in response to concerns raised in two condition reports, the licensee did not adequately address that the as-built support configuration had not been properly verified from a design standpoint. In particular, the licensee did not consider the safety-related classification of nearby containment/drywell atmosphere monitoring tubing and that this tubing could be impacted if the HPU piping failed during a postulated design basis seismic event. Hence, the licensee did not implement the additional evaluation/calculations required to demonstrate the HPU piping met more stringent design requirements and was adequately supported. The primary cause of the violation was related to the cross-cutting component of Human Performance, Resources (H.2(c)) because the licensee failed to maintain complete, accurate, and up-to-date design documentation. Subsequently, the licensee performed evaluations/calculations demonstrating that the HPU piping will not adversely impact the safety-related containment monitoring tubing during a design basis seismic event. The licensee entered the finding in the corrective action program as Action Request 723620.

The finding was more than minor because it was associated with the Barrier Integrity Cornerstone and affected the cornerstone objective of maintaining functionality of containment due to the potential impact on the safety-related containment atmosphere monitoring system which was needed to monitor and to take actions to mitigate challenges to containment integrity. The finding was of very low safety significance because the licensee's preliminary results based on conservative calculations indicated that the design basis requirements were met, and hence field modifications were not necessary. (Section 4OA2)

Cornerstone: Occupational Radiation Safety

- Green. The inspectors identified a finding of very low safety significance and an associated NCV of Technical Specification 5.7.2 for failure to barricade, lock, or continuously guard a high radiation area with dose rates greater than 1000 millirem per hour. On January 24, 2008, licensee staff failed to properly barricade and lock or guard three entrances to the under vessel area of the drywell. As corrective actions, the licensee suspended access to the Radiologically Controlled Area (RCA) for the personnel involved and initiated a prompt investigation, including assessment of the extent of condition plant-wide. The licensee entered the issued into the corrective action program as Issue Report (IR) 726499.

  The finding was more than minor because it was associated with the Program/Process attribute of the Occupational Radiation Safety Cornerstone and affected the cornerstone objective to ensure worker health and safety from exposure to radiation, in that, failure to follow procedures for control of locked high radiation areas could result in unplanned exposure. The finding was determined to be of very low safety significance because the finding did not involve As-Low-As-Is-Reasonably-Achievable (ALARA) planning, collective dose was not a factor, it did not involve an overexposure, there was not a substantial potential for a worker overexposure, and the licensee's ability to assess worker dose was not compromised. Additionally, this finding has a cross-cutting aspect in the area of Human Performance because radiation protection staff did not appropriately follow procedures (H.4(b)) which governed control of access into locked high radiation areas. (Section 2OS1)

B. Licensee-Identified Violations

None.

REPORT DETAILS

Summary of Plant Status

At the beginning of the inspection period, the plant was operated at approximately 90 percent rated thermal power (maintaining 95 percent electrical output) due to being in coast down operation. On January 12, 2008, the operators shut the reactor down to begin Clinton Power Station's eleventh refueling outage (C1R11). Reactor restart from C1R11 was commenced on February 4, 2008. The refueling outage was completed on February 5, 2008.

On February 10, 2008, an automatic scram occurred. A high reactor water level condition caused the scram. This condition occurred following a trip of the 'B' reactor recirculation pump. The licensee began startup operation on February 11, 2008, and entered mode one on February 12, 2008. Full power operation was achieved on February 13, 2008. The plant was returned to 96 percent rated thermal power on February 13, 2008, and remained there through the close of the inspection period.

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

The inspectors performed partial system walkdowns of the following risk-significant systems:

- Reactor Core Isolation Cooling System.
- High Pressure Core Spray System.
- Low Pressure Core Spray System.
- Division 1, Emergency Diesel Generator.

The inspectors selected these systems based on their risk significance relative to the Reactor Safety Cornerstones at the time they were inspected. The inspectors attempted to identify any discrepancies that could impact the function of the system, and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, system diagrams, Updated Final Safety Analysis Report (UFSAR), Technical Specification (TS) requirements, Administrative TS, outstanding work orders, condition reports, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the systems incapable of performing their intended functions. The inspectors also walked down accessible portions of the systems to verify system components and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the corrective action program with the appropriate significance characterization. Documents reviewed are listed in the Attachment.

These activities constituted four partial system walkdown samples as defined in Inspection Procedure 71111.04-05.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

The inspectors conducted fire protection walkdowns which were focused on availability, accessibility, and the condition of fire fighting equipment. The control of transient combustibles, ignition sources, and the condition of installed fire barriers was also reviewed. The inspector selected fire areas for inspection based on overall contribution to internal fire risk and the potential to impact equipment, which could cause a plant transient. The inspector also verified the following:

- Fire Area CB-4, Elevation 781’ – 0’ Division 1, Cable Spreading Room;
- Fire Area A-2c, Low Pressure Core Spray;
- Fire Area CB-1c, Division 1 and 2 Stand By Gas Treatment;
- Fire Zone F1-m Elevation 737’ Fuel Building;
- Fire Area D-5D Division 1 Diesel Generator Room;
- Fire Area A-1, 707’ and 737’ Auxiliary Building General Access;
- Fire Area C-1 elevations 707’, 737’ and 768 and
- Fire Zone CB-6a, 6b and 6c, Elevation 800’ Main Control Room.

The inspectors reviewed portions of the licensee’s fire protection evaluation report and the USAR to verify consistency in the documented analysis with installed fire protection equipment at the station.

These activities constituted eight fire protection walkdown samples as defined in Inspection Procedure 71111.05Q.

b. Findings

Introduction: The inspectors identified a performance deficiency involving a Non-Cited Violation (NCV) of Clinton Power Station Operating License NPF-62, Section 2.F for failure to implement the fire protection program in accordance with program requirements. The inspectors identified multiple instances of the licensee’s failure to follow approved fire protection program procedures concerning control of transient combustible material.

Description: Throughout the inspection period, the inspectors identified multiple instances where the licensee failed to follow fire protection program procedures. For example, on March 6, 2008, the inspectors observed unattended transient combustible items (plastic tool cart containing a plastic toolbox, absorbent pads, and other plastic/rubber items) staged on the Control Building 781' elevation. The area in which the transient combustible items were located contained highly visible red stripes on the floor and markings indicating "Combustible Free Zone." A note in OP-AA-201-009, "Control of Transient Combustibles," states that Striped Red Floor areas and areas posted by signage at Clinton Power Station are provided for separating redundant Safe Shutdown Equipment. The licensee had posted this area as a "Combustible Free Zone," although licensee procedure OP-AA-201-009, Attachment 5, identifies this area as a Transient Combustible Free Zone. Licensee procedure OP-AA-201-009 defines a "Transient Combustible Free Zone" as an area in the plant in which transient combustible material is strictly controlled. Therefore, authorization in the form of a Transient Combustible Permit is required prior to staging or storing any transient combustibles in the area. Attachment 5 of OP-AA-201-009 states, "placement of transient combustible material in specified area without prior approval and additional compensatory measures is prohibited in Modes 1, 2, and 3." The inspectors immediately notified the licensee regarding this issue. Soon after the inspectors notified the licensee regarding this issue, the licensee initiated a Transient Combustible Permit and appropriate compensatory measures in this area, and Issue Report 745791 was initiated. Both licensee procedure OP-AA-201-009 and Clinton Power Station (CPS) procedure 1893.01, "Fire Protection Impairment Reporting," require that compensatory measures be established when combustible material is staged in a combustible free zone.

During a plant walkdown on January 19, 2008, the inspectors noted combustible items (RM-20 Frisker and extension cord) staged in the east Auxiliary Building 737' elevation stairwell. This was contrary to licensee procedure OP-AA-201-009, section 4.4.1.7 which states, in part, "DO <u>not</u> STAGE or STORE transient combustible materials … inside or beneath stairwells …" There was no Transient Combustible Permit attached to the items. The inspectors notified the licensee of this issue. During the subsequent extent of condition walkdown of other stairwells in the Auxiliary Building, the licensee identified another RM-20 Frisker and extension cord inside a stairwell. The combustible items were relocated to approved locations and IR 724449 was initiated.

Other examples included plant walkdowns, conducted throughout Refueling Outage C1R11, where the inspectors noted transient combustible items stored/staged on the top shelf of various shelving units located throughout the plant. Prior to and during the refueling outage, numerous shelving units were erected throughout the plant for staging parts, tools, etc. The majority of these shelving units were posted with signage prohibiting the storage/staging of combustible materials on the top shelf in accordance with licensee procedure OP-AA-201-009. The prohibition was due to the top shelf being in close proximity (within 10 vertical feet) of horizontal cable trays (OP-AA-201-009, section 4.4.2.6). On several occasions during plant walkdowns the inspectors observed combustible items (e.g., plastic bins, plastic buckets, materials inside plastic bags) being stored on the top shelves of these units contrary to the posted signage. All combustible materials observed were Class A material (i.e., ordinary combustibles). The licensee was notified of these issues, the combustible materials were moved or removed, and Issue Reports 717441, 724449, 726603, 727159, and 730045 were initiated to document the occurrences.

<u>Analysis</u>: The inspectors determined that the licensee's failure to follow the procedural requirements of Clinton Power Station's fire protection program was a performance

deficiency warranting a significance evaluation in accordance with Inspection Manual Chapter (IMC) 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," issued on September 20, 2007. Specifically, the licensee failed to appropriately implement procedures governing the control of transient combustibles. The inspectors determined that this issue was more than minor because as stated in IMC 0612, Appendix E, Section 4, Example H; the issue is not minor if the identified transient combustibles were in a combustible free zone required for separation of redundant trains.

Using IMC 0609, Appendix F, "Fire Protection Significance Determination Process," the inspectors determined that this issue involved the finding category "Fire Prevention and Administrative Controls." Referencing IMC 0609, Appendix F, Attachment 2, "Degradation Rating Guidance Specific to Various Fire Protection Program Elements," the inspectors assigned a "Low Degradation" rating to the issues involving the failure to comply with the licensee transient combustible program. The inspectors' conclusions were based on the fact that none of the items found in the combustible free zone could be considered transient combustibles of significance, as described in IMC 0609, Appendix F, Attachment 2. This attachment defines transient combustibles of significance as low flash point liquids (below 200 deg. F) and self-igniting combustibles (oily rags). Because this issue was assigned a "low degradation" rating this issue was of very low safety significance (Green) in accordance with IMC 0609, Appendix F, Task 1.3.1.

<u>Enforcement</u>: Operating license NPF-62, Section 2.F states: "The licensee shall implement and maintain in effect all provisions of the approved fire protection program as described in the final safety analysis report (FSAR) as amended, for the CPS and as approved in the Safety Evaluation Report (SER) (NUREG-0853) dated February 1982 and Supplement Numbers 1 through 8."

Updated Safety Analysis Report, Appendix E, Section 4.0, "Fire Protection Evaluation Report Compliance with BTP APC9.5-1, Appendix A, Plant Under Construction and Operating Plant Program," contains program requirements of the licensee fire protection program. Fire Protection Evaluation Report, Section C.2, "Instructions, Procedures, and Drawings" states the inspections, tests, administrative controls, fire drills and training that govern the fire protection program should be prescribed by documented instructions, procedures, or drawings and should be accomplished in accordance with these documents.

Contrary to the above, the inspectors identified multiple instances where the licensee failed to follow fire protection procedures OP-AA-201-009 (Transient Combustible Control) and CPS 1983.01 (Fire Protection Impairment Reporting). This was a violation of the licensee's operating license NPF-62, section 2.F, relating to the fire protection program. The licensee's corrective actions for this issue included removing combustible material out of combustible free zones, issuing transient combustible permits, and/or initiating compensatory measures, as appropriate. Because this issue was of very low safety significance and has been entered into the licensee's corrective action program (Issue Report 00745791), this violation is being treated as a NCV, consistent with Section VI.A, of the NRC Enforcement Policy. **(NCV 05000461/2008002-01)**.

Throughout the inspection period, the inspectors identified multiple instances of the licensee failing to identify compliance with the transient combustible material control program. Because the licensee personnel had not self-identified and corrected these issues through the corrective action program prior to the inspectors' identification of these issues, the inspectors concluded that the primary cause of this finding was related to the cross-cutting aspect of Problem Identification and Resolution. Specifically, the licensee implements a corrective action program with a low threshold for identifying issues. The licensee identifies such issues completely, accurately, and in a timely manner commensurate with their safety significance. P.1(a)

1R08 Inservice Inspection Activities (71111.08)

.1 Piping Systems Inservice Inspection (ISI)

a. Inspection Scope

From January 14, 2008, to January 18, 2008, the inspectors conducted a review of 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 the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section XI required examinations and code components in order of risk priority as identified in Section 71111.08-03 of IP 71111.08, "Inservice Inspection Activities," based upon the ISI activities available for review during the onsite inspection period.

The inspectors performed a record review of the following non-destructive examination activities to evaluate compliance with the ASME Boiler and Pressure Vessel Code requirements and to verify that indications and defects were dispositioned in accordance with the ASME Code.

The inspectors performed a record review of the following examinations:

- Ultrasonic Examination (UT) of the residual heat removal (RH) heat exchanger nozzle to head inner radius weld, HEA-3 IRS, Report No. C1-002;
- Ultrasonic Examination of the RH elbow to pipe weld, 1-RH-9-13-7, Report No. C1-010;
- Ultrasonic Examination of the RH tee to elbow weld, 1-RH-9-13-5, Report No. C1-011;
- Magnetic Particle Examination (MT) of the RH heat exchanger nozzle to head weld, HEA-3, Report No. C1-001; and
- Visual Examination (VT) Of The Shutdown Service Water (SX) attachment lug weld, 1SX110022X-WA, Report No. C1-009.

The inspector requested examinations completed during the previous outage with relevant/recordable conditions/indications that were accepted for continued service to verify that the licensee's acceptance was in accordance with the Section XI of the ASME Code. No relevant indications accepted for continuous service from the previous outage were identified.

The inspectors reviewed pressure boundary welds for a Class 1 system, which was completed since the beginning of the previous refueling outage to determine if the welding NDE examinations were performed in accordance with ASME Code requirements. Specifically, the inspectors reviewed documentation for welds associated with the following work activities:

- The inspector reviewed a Reactor Core Isolation Cooling (RCIC) head spray piping modification WO# 00803566 performed to lower line 1RI03C-4" between the RCIC head spray nozzle 1B13-D020 and RCIC injection check valve 1E51-F066. The inspector reviewed the five ASME Code Class 1 pressure boundary welds performed last outage for the reroute of the RCIC head spray piping 1RI03C-4" to determine if the welding was performed in accordance with ASME Code requirements.

b. Findings

No findings of significance were identified.

.2 Identification and Resolution of Problems

The inspectors reviewed a sample of ISI/SG related problems documented in the licensee's corrective action program to assess conformance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. In addition, the inspectors verified that the licensee correctly assessed operating experience for applicability to the Inservice Inspection group.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations (71111.12Q)

a. Inspection Scope

The inspectors evaluated degraded performance issues involving the following risk-significant systems:

- Reactor Feed Water Level Control System and
- Division 1 Neutron Monitoring System.

The inspectors reviewed events such as where ineffective equipment maintenance had resulted in valid or invalid automatic actuations of engineered safeguards systems and independently verified the licensee's actions to address system performance or condition problems in terms of the following:

- implementing appropriate work practices;
- identifying and addressing common cause failures;
- scoping of systems in accordance with 10 CFR 50.65(b);
- characterizing system reliability issues for performance;
- charging unavailability for performance;
- trending key parameters for condition monitoring;
- ensuring 10 CFR 50.65(a)(1) or (a)(2) classification or re-classification; and

- verifying appropriate performance criteria for structures, systems, and components (SSCs)/functions classified as (a)(2) or appropriate and adequate goals and corrective actions for systems classified as (a)(1).

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the system. In addition, the inspectors verified maintenance effectiveness issues were entered into the corrective action program with the appropriate significance characterization. Documents reviewed are listed in the Attachment.

This inspection constitutes two quarterly maintenance effectiveness samples as defined in Inspection Procedure 71111.12-05.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

.1. Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors reviewed the licensee's evaluation and management of plant risk for the maintenance and emergent work activities affecting risk-significant and safety-related equipment listed below to verify that the appropriate risk assessments were performed prior to removing equipment for work:

- WO# 706232-01 and 03, "Inspect 1VX03YA and 1VX04YA Switchgear Heat Removal System and Replace Hydramotor"
- WO# 910656.663, "De-energization of Division 2 NSPS Inverters for UTI"
- Reviewed licensee risk assessment for performance of CPS 9080.23, "Division 3 Integrated testing during repair of 1E12-F009"
- WO# 1036643, "As-found VT-3 Inspection of Snubbers in Subsystem 1RH09, 1RT06 and 1SX08"
- Reviewed Work Week 810 - Division 1 EDG monthly surveillance test and quick start, Division 1 4kV 2nd level UV relay testing, flushing 1SX105BA line, WO# 00912870-03, and 1FW004 WO# 01010594-05
- Reviewed Work Week 811 work activities - Reactor recirculation system root cause troubleshooting, concurrent with maintenance activities for the motor driven reactor feed pump

These activities were selected based on their potential risk significance relative to the Reactor Safety Cornerstones. As applicable for each activity, the inspectors verified that risk assessments were performed as required by 10 CFR 50.65(a)(4) and were accurate and complete. When emergent work was performed, the inspectors verified that the plant risk was promptly reassessed and managed. The inspectors reviewed the scope of maintenance work, discussed the results of the assessment with the licensee's probabilistic risk analyst or shift technical advisor, and verified plant conditions were consistent with the risk assessment. The inspectors also reviewed TS requirements and walked down portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met.

These activities constituted six samples as defined in Inspection Procedure 71111.13-05.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- Reactor Core Isolation Cooling System Steam Line Differential Pressure Anomalies
- High Pressure Core Spray Room Cooler Relief Valves lifted during Diesel Generator 1C Integrated Test

The inspectors selected these potential operability issues based on the risk significance of the associated components and systems. The inspectors evaluated the technical adequacy of the evaluations to ensure that TS operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the Clinton TS and USAR to the licensee's evaluations, to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations. Additionally, the inspectors also reviewed a sampling of corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Documents reviewed are listed in the Attachment.

This inspection constitutes two samples as defined in Inspection Procedure 71111.15-05.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

The inspectors reviewed one permanent plant modification that had been installed in the plant during the last three years. The modification was chosen based upon risk significance, safety significance, and complexity. As per inspection procedure 71111.17, one modification was chosen that affected the design bases and functioning of interfacing systems as well as introducing the potential for common cause failures. The inspectors reviewed the modifications to verify that the completed design changes were in accordance with the specified design requirements, and the licensing bases, and to confirm that the changes did not adversely affect any systems' safety function. Design and post-modification testing aspects were verified to ensure the functionality of the modification, its associated system, and any support systems. The inspectors also verified that the modification performed did not place the plant in an increased risk configuration.

The inspectors also used applicable industry standards to evaluate acceptability of the modification. The list of modification and other documents reviewed by the inspectors is included as an Attachment to this report. The inspectors reviewed WO# 1075907, "Use a mechanical clamp gag applied externally to 1B21-F065A."

This inspection constitutes one sample as defined in Inspection Procedure 71111.17-05.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance (PM) Testing (71111.19)

.1 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed the following PM activities to verify that procedures and test activities were adequate to ensure system operability and functional capability:

- WO# 0067125, "Repair of 'A' Feedwater Isolation Valve 1B21-F065A"
- Replacement of Turbine Driven Reactor Feed Pump Oil Pressure Switch
- VG Damper Hydramotor Replacement
- WO# 901661-03 for validation of Post-Maintenance Testing
- WO# 910656.663, "Division 2 Untested Islands (UTI) Calibration and Replacements"
- WO# 983843-04, "CPS 3501.01 Section 8.1.3"

These activities were selected based upon the structure, system, or component's ability to impact risk. The inspectors evaluated these activities for the following (as applicable): the effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed; acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate; tests were performed as written in accordance with properly reviewed and approved procedures; equipment was returned to its operational status following testing (temporary modifications or jumpers required for test performance were properly removed after test completion), and test documentation was properly evaluated. The inspectors evaluated the activities against TS, the UFSAR, 10 CFR Part 50 requirements, licensee procedures, and various NRC generic communications to ensure that the test results adequately ensured that the equipment met the licensing basis and design requirements. In addition, the inspectors reviewed corrective action documents associated with post-maintenance tests to determine whether the licensee was identifying problems and entering them in the corrective action program and that the problems were being corrected commensurate with their importance to safety. Documents reviewed are listed in the Attachment.

This inspection constitutes six samples as defined in Inspection Procedure 71111.19-05.

b. Findings

Introduction: A finding of very low safety significance was self-revealed by the automatic runback of the turbine driven reactor feed pump (TDRFP) during post-outage power ascension. The licensee discovered that the wrong component was installed in the B TDRFP oil pressure sensing logic. The inspectors determined that the licensee failed to perform an adequate post-maintenance test in accordance with procedures. This issue resulted in an unexpected power change from 54 percent power to 46 percent power.

Description: In November 2007, an instrument technician requested a pressure switch from the material control group for work associated with the B TDRFP. Hydraulic oil trip header pressure switch 1PS-FW 135 was to be replaced as a preventative maintenance activity. The pressure switch was received by the technician and calibrated in accordance with Instrument Calibration Procedure CPS No. 8801.01. The pressure switch was then placed in a staging area for installation during refueling outage C1R11. In January of 2008, the pressure switch was installed.

On February 6, 2008, the plant was in the post-outage process of power ascension when an automatic reactor recirculation 'B' flow control valve runback occurred. The runback feature is designed to reduce reactor power to within the capacity of a single reactor feed pump in order to prevent a reactor trip on low water level. When the water level in the vessel reached level four (30.8 inches), the runback logic determined that the B TDRFP was not running due to improper contacts on the hydraulic oil trip header pressure switch. This caused the plant to move from approximately 54 percent reactor power to approximately 46 percent reactor power.

The licensee's investigation of this event discovered that the pressure switch, 1PS-FW135, was not functioning in accordance with expectations. Further investigation identified that the switch that had been installed was not configured properly. Specifically, the correct switch configuration should have consisted of one set of normally open contacts and one set of normally closed contacts. The configuration installed was two sets of normally closed contacts.

The licensee focused on two factors as being the primary contributors to this event. The first was the acquisition and issuance of the wrong switch. The licensee discovered that this particular pressure switch could not be identified explicitly by its part number alone. Additional Information was required to identify the "Form" of the switch. The appropriate Form for the hydraulic oil trip header pressure switch was Form H. The requisition sheet for the pressure switch that had been installed designated no form type.

The licensee also identified a human performance issue associated with the initial calibration of the pressure switch. The data sheet associated with the calibration work order clearly identified the second set of contacts, Output #2, as normally open contacts. The technician had adjusted the pressure to respond to the input requirements: i.e. with pressure increasing, changes state at a given value. The technician failed to notice that the initial state of the second set of contacts did not match the description. The calibration procedure did not contain an independent step to verify the contact configuration. The state of the switch was described in such a way that it was not possible to meet the acceptance criteria and have an incorrect contact type. Therefore, the licensee concluded that the technician who performed the calibration inappropriately indicated that the results of the calibration were satisfactory.

The inspectors evaluated this event from a defense in depth perspective. The inspectors took no issue with the licensee's identification of primary contributors associated with this event. The procurement process was the first barrier to be compromised. The human error associated with the calibration of the pressure switch represented the first discovery opportunity. The second opportunity was the post-maintenance test. In this case, the work package directed the maintenance personnel to ensure the electrical connections were secure; that there was no hydraulic leakage; and all mounting hardware was properly tightened.

The licensee's procedure MA-AA-716-012, "Post-Maintenance Testing," step 1.2.3, states that MA-AA-716-012 establishes guidance for the determination of appropriate testing based on maintenance performed. For the replacement of a pressure switch and calibration, the inspectors identified the following note under the Control Circuits Test Matrix section in Attachment 1 of this procedure, "Verify that for a known input the expected result is received. Testing will verify expected result is observed at least one point beyond the affected component." Independent of the first failed barrier (equipment issuance process) and the missed opportunity to discover this issue (during component calibration), the inspectors concluded that if the post-maintenance test had been conducted in accordance with MA-AA-716-012, the licensee would have identified this issue prior to experiencing the unexpected power transient.

<u>Analysis</u>: The inspectors concluded that the licensee's failure to perform an adequate post-maintenance test of the TDRFP oil pressure switch resulted in an expected plant transient. The licensee's action during this event was contrary to the licensee's post-maintenance testing procedure and was a performance deficiency.

The finding was determined to be more than minor because the finding was associated with the Human Performance attribute of the Initiating Events Cornerstone and affected the cornerstone objective of limiting the frequency of those events that upset plant stability. Specifically, the failure to perform adequate post-maintenance testing of pressure switch 1PS-FW 135 permitted a deficient component to be installed. This deficiency ultimately resulted in a plant transient.

The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase -1 Initial Screening and Characterization of Findings," Table 4a for the Initiating Events Cornerstone. The inspectors determined that the performance deficiency resulted in an unplanned change in reactor reactivity and therefore affected the Transient Initiator Contributor attribute of the Initiating Events Cornerstone. The inspectors determined that the finding affected the safety of an operating reactor and therefore affected the Initiating Event Cornerstone. The Inspectors answered "No" to Question 1: Does the finding contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available? As a result the finding was screened to be of very low safety significance, "Green"

(FIN05000461/2008002-02). The inspectors also concluded that failure of the technician to properly follow calibration procedure 8801.01 during the initial calibration of this switch represented a cross-cutting issue in the area of Human Performance, Work Practices (H.4(b)), personnel work practices support human performance. Specifically, H.4.b. states that the licensee defines and effectively communicates expectations regarding procedural compliance and personnel follow procedures. The licensee's corrective actions for this issue included performing a tailgate discussion with all Instrument Maintenance Department technicians and work planners regarding the variable options associated with oil pressure switches from the switch manufacturer, including the fact that one part number may have multiple configurations. Additionally, the licensee performed corrective actions to ensure that all of the vendor purchase specifications for these types of pressure switches were up-to-date in the materials and work management computer system. This issue was documented in the licensee's corrective action program as Issue Report 73626.

Enforcement: No violation of regulatory requirements occurred.

1R20 Outage Activities (71111.20)

.1 Refueling Outage Activities

a. Inspection Scope

The inspectors reviewed the Outage Safety Plan (OSP) and contingency plans for the refueling outage to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. During the refueling outage, the inspectors observed portions of the shutdown and cooldown processes and monitored licensee controls over the outage activities listed below.

- Licensee configuration management, including maintenance of defense-in-depth commensurate with the off-site power for key safety functions and compliance with the applicable Clinton TS for taking equipment out of service;
- Implementation of clearance activities and confirmation that tags were properly hung and equipment appropriately configured to safely support the work or testing;
- Installation and configuration of reactor coolant pressure, level, and temperature instruments to provide accurate indication, accounting for instrument error;
- Controls over the status and configuration of electrical systems to ensure that Clinton TS and offsite power requirements were met, and controls over switchyard activities;
- Monitoring of decay heat removal processes, systems, and components;
- Controls to ensure that outage work was not impacting the ability of the operators to operate the spent fuel pool cooling system;
- Reactor water inventory controls including flow paths, configurations, and alternative means for inventory addition, and controls to prevent inventory loss;
- Controls over activities that could affect reactivity;
- Maintenance of secondary containment as required by Clinton TS;
- Refueling activities, including fuel handling;

- Startup and ascension to full power operation, including tracking of startup prerequisites and reactor physics testing;
- Walk down and closeout of the drywell (primary containment) to verify that debris had not been left which could block emergency core cooling system suction strainer; and
- Licensee identification and resolution of problems related to refueling outage activities.

The following is a partial list of the licensee procedures referenced during the inspection:

- OP-AA-108-108, “Unit Restart Review”
- OP-AA-108-108-1001, “Drywell Closeout”
- OP-AA-108-115, “Operability Determinations”
- CPS 9861.01, “Integrated Leak Rate Test,” Revision 24

This inspection constitutes one refueling outage sample as defined in Inspection Procedure 71111.20-05.

b. Findings

Introduction: The inspectors identified a finding of very low safety significance. During the performance of NRC final drywell closeout, the inspectors noted that the licensee had not removed foreign material/housekeeping socks from the drywell floor. This issue could have resulted in the drywell leak detection system being inoperable following a reactor event.

Description: On February 4, 2008, the inspectors performed a drywell closeout inspection in accordance with NRC Inspection Procedure 71111.20. During the closeout inspection, the inspectors identified that the licensee had failed to remove socks from the drywell floor drains during the licensee’s final closeout inspection. According to the licensee, the socks were installed following initial entry into the drywell at the beginning of the outage as part of the station housekeeping and material conditional program. The socks are used to prevent foreign material from entering the drywell floor drain sump. These socks were required to be removed prior to drywell closeout. During the drywell closeout inspection, the inspectors also noted that some of the floor drain socks contained foreign material.

During a design basis accident involving a high-energy line break, loose foreign material would be generated. The inspectors were concerned that these socks would become loaded with foreign material and represent a clog in the drywell floor drain sump system, which would delay and prevent the collection of unidentified leakage in the drywell floor drain sumps. This issue would result in the drywell floor drain sump flow detector system, which consists of the drywell floor drain sump level transmitter and a programmable logic controller, not accurately detecting changes in drywell floor drain sump levels. The programmable logic controller calculates the rate of level change for the drywell sump by sampling sump level once per minute when the drywell floor drain sump pumps are off.

In Action Request 00731159 Assignment 4, the licensee documented that the removal of the drain socks was missed due to only scheduling one activity to install the socks, “DW-Clean-Install Drain Socks, General Housekeeping.” No activity existed to remove the drain socks. Failure to adequately track the removal of the drain socks could have affected the operability or reliability of the drywell leak detection systems.

During the closeout inspection, the inspectors also noted additional loose debris on the drywell basement floor that had not been removed by the licensee during final closeout inspection. These items included four 12”x12” oil absorbent pads and miscellaneous debris underneath the drywell coolers.

Analysis: The inspectors determined that the licensee’s failure to follow the procedural requirements for drywell closeout inspections was a performance deficiency warranting a significance evaluation in accordance with IMC 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Screening,” issued on September 20, 2007. The issue was more than minor because, if left uncorrected, it could result in a more significant safety concern. Failure to remove drain socks from drywell floor drains could result in the inability to readily detect and track unidentified leakage following a reactor event.

In addressing the significance of this issue, the inspectors referred to Table 2, of NRC IMC 0609.04. In Table 2, Barrier Integrity Cornerstone column, the inspectors noted that the instructions direct that all findings, other than reactor coolant system (RCS) boundary issues as a mitigator following plant upset, be addressed under the Initiating Events cornerstone. Using Table 4A of IMC 0609.04, the inspectors determined that because this finding did not result in exceeding the TS limit for RCS leakage and did not affect other mitigating systems resulting in a total loss of their safety function, this issue screens as Green.

Enforcement: Appendix B, Criteria V, 10 CFR 50, Instructions, Procedures , and Drawings, states that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance the these instructions, procedures, or drawings.

Clinton Power Station Procedure 3021.01, “Drywell Close Out,” section 8.2.1.10 directs plant personnel to verify the drywell is free of transient equipment/material, including tools rags, or other material left astray per criteria in MA-CL-716-026, ‘Station Housekeeping/Material Condition Program.” Contrary to the above, on February 5, 2008, the inspectors identified that the licensee failed to verify the drywell was free of transient equipment/material in accordance with CPS 3021.01. The licensee’s corrective actions for this issue included removing the floor drain socks and incorporating a work item for sock removal in the outage schedule template. Because this issue was of very low safety significance and has been entered into the licensee’s corrective action program (Issue Report 00745791), this violation is being treated as a NCV, consistent with Section VI.A, of the NRC Enforcement Policy **(NCV 05000461/2008002-03)**.

The primary cause of this failure was related to the cross-cutting component of Human Performance, Work Control (Item H.3. (b) of IMC 305) because licensee personnel failed to plan and coordinate work activities, consistent with nuclear safety.

1R22 Surveillance Testing (71111.22)

.1 Routine Surveillance Testing

a. Inspection Scope

The inspectors reviewed the test results for the following activities to determine whether risk-significant systems and equipment were capable of performing their intended safety function and to verify testing was conducted in accordance with applicable procedural and TS requirements:

- CPS 9054.01, Revision 042e, "Reactor Core Isolation Cooling System Low Pressure Testing;"
- CPS 9080.21, Revision 28, "Diesel Generator 1A-ECCs Integrated;"
- CPS 9861.04, "Main Steam Line Isolation Valve Local Leak Rate Test," Revision 26;
- CPS 9051.01, Revision 042, "High Pressure Core Spray Pump and High Pressure Core Spray Water Leg Pump Operability;"
- CPS 9080.03, Revision 209, "Diesel Generator 1C Operability;"
- CPS 9861.09D008, "Shutdown Service Water Boundary Test 1SX-14A;"
- CPS 9843.01V004, "Category A ISI Valve lineup and Testing on 1E12-F495A, 1E12-F496 and 1E12-F495B;"
- CPS 9432.61, "CRVIS Fuel Building Exhaust 1RIX-PR06A," Revision 041;
- CPS 9843.010004, Revision 27A, "Leak Rate Testing of LPC1 'C' Injection."

The inspectors witnessed selected surveillance testing and/or reviewed test data to verify that the equipment tested using the surveillance procedures met the TS, the Technical Requirements Manual (TRM), the USAR, and licensee procedural requirements, and demonstrated that the equipment was capable of performing its intended safety functions. The activities were selected based on their importance in verifying mitigating systems capability and barrier integrity. The inspectors used the documents listed at the end of this report to verify that the testing met the frequency requirements; that the tests were conducted in accordance with the procedures, including establishing the proper plant conditions and prerequisites; that the test acceptance criteria were met; and that the results of the tests were properly reviewed and recorded. In addition, the inspectors interviewed operations, maintenance, and engineering department personnel regarding the tests and test results.

This inspection constitutes five routine surveillance testing samples, three samples involved containment isolation valve testing and one sample involved an Inservice testing activity as defined in Inspection Procedure 71111.22, sections -02 and -05.

b. Findings

Unresolved Item (URI) 20080002-01 As-Found Leakage Through Shutdown Service (SX) Valve 1SX014A.

Introduction: The inspectors reviewed the results of CPS 9861.09D008, "Leakage Test on Valve 1SX014A." This procedure provides direction for performing leak rate testing for the shutdown service water (SX) to normal service water system isolation valves to assist in the operability determination of the ultimate heat sink and the SX system. The procedure is performed every 24 months per Appendix V of the licensee's Inservice Inspection Manual. The SX014A valve failed as-found testing due to excessive leakage following closure of the valve. During the test, the licensee was unable the quantify leakage past 1SX014A due to system test alignment and test connection limitations.

Description: On January 22, 2008, operators identified a significant leak on the 1SX014A valve after the valve was closed. The valve was taken to the closed position by operators to perform a leakage test on the valve per CPS 9861.09D008, "Leakage Test on Valve 1SX014A."

Valve 1SX014A is the shutdown service water to normal plant service water isolation valve. During normal operation, the valve is open. The valve closes automatically when the shutdown service water pump starts. This valve was installed to ensure the shutdown service water system remains capable of performing its design purpose without being compromised by the less stringent design requirements of the normal plant service water system. The valve is a 20-inch motor-operated butterfly valve.

As required by step 8.2.1.2 of CPS 9861.09D008, the operators attempted to drain the test volume by opening the SX Division I supply header low point drain valve (1SX078A) and the two three-inch drain lines off the shutdown service water strainer basket (1SX171A and 1SX013A). The operators could not obtain a drained system. With the valves open, pressure on the discharge side of the strainer dropped to 13 psi. Using the valve position indications, the 1SX014A valve was verified shut locally, however the flow noise at 1SX014A continued and the differential pressure reading at the strainer indicated that 1SX014A was leaking by significantly. Despite not being able to get the system drained, operators re-established the leak test alignment (closed 1SX171A and 1SX013A) and attempted to perform a leak test. This attempt was made using the test connection at 1SX078A and a 55 gallon graduated barrel. The operators stated that with approximately two turns open on 1SX078A, the barrel filled in a few seconds (~ six seconds). The in-field operator recalled that following this test, control room staff stated system pressure was approximately 8 psi based on control room pressure indicator 1SXPI028. The licensee documented the test results in AR 725079. However, when the inspectors requested copies of the actual data sheet used during the leak test, the licensee was unable to provide copies of the surveillance test results.

According to the licensee's equipment apparent cause report, the valve was leaking by the seat. The failure mechanism was general corrosion of the valve body due to prolonged exposure to raw service water and possibly some contribution from microbiologically induced corrosion (MIC). The licensee investigation also concluded that galvanic effects might have played a role due to the interaction between the 316 stainless steel valve disc and the carbon steel valve body. Valve inspection revealed that the valve body had corroded such that the disc was not in full contact with the valve seat allowing the valve to leak by the seat (majority of seal ring detached). The valve body was made of carbon steel. The mechanical properties of carbon steel are greatly susceptible to corrosion damage, especially when there is a continuous flow of water.

In addition, the licensee's investigation determined the preventative maintenance frequency was incorrect, because the component category was incorrectly classified. The valve was classified as a Category 4 (no required inspection interval) component based on a designation of Critical–YES / Duty Cycle-LOW / Service Condition-MILD.

The licensee's review of the Performance Centered Maintenance Template and the application of this valve in raw water conditions led to the conclusion that the Service Condition should be SEVERE based on the corrosive conditions to which the valve is exposed. This would result in a classification of Category 2, which would require valve internal inspections every eight years. Therefore, the apparent cause of the failure was the incorrect application of the Performance Centered Maintenance (PCM) Template for this valve that resulted in an inappropriate PM interval for valve inspection. Prior to this failure, the licensee replaced this valve in 1997.

Preventive maintenance activities for 1SX014A were reviewed and compared against the PCM Template recommendations. Preventive maintenance and frequency for 1SX014A were consistent with the Category 4 designation, with no required interval for inspection, and with a note that the inspection frequency should be based on site-specific experience and through the use on non-intrusive testing. For a Category 2 designation, the PCM Template would require valve inspections every eight years.

During the review of the licensee's equipment apparent cause evaluation (EACE) and the issue report documenting the valve failed leak test, inspectors noted that the licensee failed to address past operability. The inspectors were concerned because the design basis of the shutdown service water system is to remove heat from equipment necessary to safely shutdown the plant and maintain a safe plant shutdown. Updated Safety Analysis Report Table 9.2.3, "Ultimate Heat Sink Auxiliary Loads from the Ultimate Heat Sink," provides a list of equipment and the heat loads cooled by the SX system. Licensee calculation IP-M-486, "Shutdown Service Water System Hydraulic Network Analysis Model and Flow Balance," outlines the procedures and assumptions used in the creation of a hydraulic network analysis model to predict the performance of the SX system during design and accident conditions. This analysis assumes a system leakage value of 300 gpm. This calculation also assumes a minimum of SX system flow to validate heat load removal capability for each auxiliary load based on SX system flow. Leakage through 1SX014A represents a diversion of a portion of the SX system flow back to the Ultimate Heat Sink without serving the required heat loads. Additionally, licensee calculation IP-M-563 establishes allowable leakage (administrative limits) from the ultimate heat sink following a postulated design basis accident and loss of the main dam.

In response to the inspectors' concern, the licensee performed an evaluation to determine the amount of leakage past 1SX014A. The licensee evaluation determined that during the leak test 1SX014A had a leak rate of approximately 636 gpm. The licensee's evaluation was based on a calculation showing the amount of flow through a fully opened 1SX078A valve at 8 psi. The licensee assumed 8 psi in the calculation based on control room staff information. Lastly, the licensee concluded that based on the past performance of the Division 1 shutdown service water pump the SX system would have been operable during the last refueling cycle.

Upon review of the detailed evaluation performed by the licensee, the inspectors noted the following concerns:

1. The licensee used a calculated leak rate through 1SX078A as equivalent to leakage from 1SX014A.

In NRC inspection report 2006-02, the inspectors documented NCV 05000461/2006-02-02 for inadequate test control. In this inspection report, the inspectors noted that Table 1, on Page 14 of calculation IP -563, "Determination of Allowable Leak Rates and Loss of UHS Volume from the SX Boundary Valves," stated that the operability limit for leakage past an UHS boundary valve should normally be considered 100 gpm. However, since the test connection (1SX078A) is a 2.5-inch valve, approximately 55 gpm can be measured without interference from the test equipment. The inspectors concluded that based on restricted flow at the entrance test connection (30 inch discharge piping and 2 ¾-inch low-pressure drain line), observations of greater than 100 gpm leakage would be unreliable. Additionally, the inspectors concluded that, due to the test arrangement during the performance of the surveillance test, additional valve flow may be unaccounted for in other portions of the SX system.

2. The licensee's use of eight psig as the limiting pressure for the evaluation.

The inspectors noted that this pressure, as indicated on 1PI-SX028 (SX strainer outlet pressure indicator), may not be conservative in determining the movement of flow through the system. According to Sargent and Lundy instrument data sheet "EI-601," 1PI-SX028 has an accuracy of +/- 2 percent of the scale range (+/- 4 psi). The scale range of 1PI-SX028 is 0-200 psi. Using this information, the inspectors determined that a conservative approach to evaluating system leakage would be to evaluate the leakage at 8 psi +/- 4 psi. Given that the instrument tap for the transmitter (1PT-SX028) was at the top of the pipe and the centerline of the 30 inch pipe was at plant elevation 702 ft. 6 inches, this issue could have a substantial effect on the licensee's evaluation, in that, at 9.7 psi of static head the height of the water column is such that some of the leakage could have been lost through SX branch line 1SX02AA-30. Shutdown service water line 1SX02AA-30 is a 30-inch branch line off the main supply that enters the fuel building at plant elevation 726 ft. 5 inches (centerline). The highest water column height at a static head of 12 psi would be approximately plant elevation of 731 ft. 4 inches. At this height, the inspector concluded that flow through 1SX02AA-30 would not represent a closed system as assumed in the licensee detailed evaluation.

Additional information has been requested of the licensee regarding specific details of past surveillance test results, complete system alignment during SX boundary valve tests, detailed piping isometrics, and the results of detailed interviews with plant operations and maintenance staff. The licensee entered this issue into its corrective action program as Action Request 00756099. Pending further review of this issue by NRC staff to determine whether the licensee's evaluation accurately bounded 1SX014A leakage, this issue is being considered an Unresolved Item **(URI 05000461/2008002-04)**.

1EP2 <u>Alert and Notification System Evaluation</u> (71114.02)

.1 <u>Alert and Notification System Evaluation</u>

a. <u>Inspection Scope</u>

The inspectors reviewed documents and held discussions with Emergency Preparedness (EP) staff regarding the operation, maintenance, and periodic testing of the Alert and Notification System (ANS) in the Clinton Plant's plume pathway Emergency Planning Zone. The inspectors reviewed daily and monthly trend reports and siren test failure records from January 2005 through February 2008. Information gathered during document reviews and interviews was used to determine whether the ANS equipment was maintained and tested in accordance with Emergency Plan commitments and procedures.

This inspection constitutes one sample as defined in Inspection Procedure 71114.02-05.

b. Findings

No findings of significance were identified.

1EP3 Emergency Response Organization Augmentation Testing (71114.03)

.1 Emergency Response Organization Augmentation Testing

a. Inspection Scope

The inspectors reviewed and discussed with plant EP staff the emergency plan commitments and procedures that addressed the primary and alternate methods of initiating an Emergency Response Organization (ERO) activation to augment the on-shift ERO as well as the provisions for maintaining the plant's ERO roster. The inspectors also reviewed reports and a sample of corrective action program records of monthly and quarterly unannounced off hour augmentation tests, which were conducted between April 2006 through December 2007, to determine the adequacy of problem identification and associated corrective actions. Additionally, the inspectors reviewed a sample of the EP training records; approximately 21 records for ERO personnel, who were assigned to key and support positions, to determine the status of their training as related to their assigned ERO positions. Lastly, the inspectors conducted walk-downs of emergency response facilities to evaluate material condition and readiness of the facilities.

This inspection constitutes one sample as defined in Inspection Procedure 71114.03-05.

b. Findings

(1) Unresolved Item (URI) 20080002-01 Changes to ERO On-Shift and Augmentation Staffing Levels and Position Titles

Introduction: The inspectors reviewed changes to the Clinton Power Station Emergency Plan Annex and the Exelon Nuclear Standardized Radiological Emergency Plan on-shift ERO minimum staffing and augmentation requirements. In 1998, the licensee increased the minimum on-shift ERO staffing from 10 to 15 positions. Between 1998 and 2008, changes to position titles or expertise may have decreased the capabilities of several specific functions.

Description: In response to problems identified during a declared Alert on February 13, 1998, the licensee added five positions to its ten required on-shift ERO staffing positions, removed the eleven 30-minute ERO augmentation positions, and added six positions to the seventeen 60-minute ERO augmentation positions. The inspectors identified that several position titles had also changed since 1998. Specifically, in 1998 four radiation protection technicians were identified in ERO positions. Two of the four technicians were to provide on-shift radiological accident assessment and operational accident assessment support, including in-plant surveys during a radiological emergency. The other two technicians were designated to provide protective actions during an emergency including access control, health physics coverage for repair, corrective actions, search and rescue, first aid, and firefighting, as well as personnel monitoring and dosimetry.

The current revision of Clinton emergency plan annex, Section 2.1, "On-Shift Emergency Response Organization Assignments," Table B-1, "Minimum Staffing Requirements for the On-Shift Clinton Station ERO," has replaced two of the radiation protection technician positions with non-licensed operators. Additional information has been requested of the licensee regarding specific position titles, functions, and additional revisions of the emergency plan minimum staffing requirements. The licensee entered this issue into its corrective action program as Issue Report 00752769. Pending further review of this issue by NRC staff to determine whether changes to position titles, functions, and responsibilities decreased the effectiveness of the emergency plan, this issue is being considered as an Unresolved Item **(URI 05000461/2008002-05)**.

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies (71114.05)

.1 Correction of Emergency Preparedness Weaknesses and Deficiencies

a. Inspection Scope

The inspectors reviewed a sample of Nuclear Oversight (NOS) Agency staff's 2006 and 2007 audits of the Clinton emergency preparedness program to determine whether these independent assessments met the requirements of 10 CFR 50.54(t). The inspectors also reviewed critique reports and samples of corrective action program records associated with the 2007 biennial exercise, as well as various EP drills conducted in 2006 and 2007, in order to determine whether the licensee fulfilled its commitments and to evaluate the licensee's efforts to identify, track, and resolve concerns identified during these activities. Additionally, the inspectors reviewed a sample of EP items and corrective actions related to the facility's EP program and activities to determine whether corrective actions were completed in accordance with the sites corrective action program.

This inspection constitutes one sample as defined in Inspection Procedure 71114.05-05.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

.1 Review of Licensee Performance Indicators for the Occupational Exposure Cornerstone

a. Inspection Scope

The inspectors reviewed the licensee's Occupational Exposure Control Cornerstone performance indicators (PIs) to determine whether the conditions resulting in any PI occurrences had been evaluated, and identified problems had been entered into the corrective action program for resolution.

This review constitutes one sample as defined in Inspection Procedure 71121.01-5.

b. Findings

No findings of significance were identified.

.2 Plant Walkdowns and Radiation Work Permit (RWP) Reviews

a. Inspection Scope

The inspectors reviewed licensee controls and surveys in the following radiologically significant work areas within radiation areas, high radiation areas and airborne radioactivity areas in the plant to determine if radiological controls including surveys, postings and barricades were acceptable:

- Inservice Inspection Inside the Drywell Bio-shield;
- Drywell Scaffolding and Permanent Shielding Installation;
- Fuel Movement and Refuel Floor Work; and
- Safety Relief Valve Removal and Replacement.

The inspectors reviewed the RWPs and work packages used to access these areas and other high radiation work areas to identify the work control instructions and control barriers that had been specified. Electronic dosimeter alarm set points for both integrated dose and dose rate were evaluated for conformity with survey indications and plant policy. Workers were interviewed to verify that they were aware of the actions required when their electronic dosimeters noticeably malfunctioned or alarmed.

The inspectors walked down and surveyed (using an NRC survey meter) these areas to verify that the prescribed RWP, procedure, and engineering controls were in place, that licensee surveys and postings were complete and accurate, and that air samplers were properly located.

The inspectors reviewed RWPs for airborne radioactivity producing work activities to verify barrier integrity and engineering controls performance (e.g., high efficiency particulate air (HEPA) ventilation system operation) and to determine if there was a potential for individual worker internal exposures of greater than 50 millirem committed effective dose equivalent. There were no airborne radioactivity work areas during the inspection period.

Work areas having a history of, or the potential for, airborne transuranics were evaluated to verify that the licensee had considered the potential for transuranic isotopes and provided appropriate worker protection.

The adequacy of the licensee's internal dose assessment process for internal exposures greater than 50 millirem committed effective dose equivalent was assessed. There were no internal exposures greater than 50 millirem committed effective dose equivalent.

These reviews constitute five samples as defined in Inspection Procedure 71121.01-5.

b. Findings

One finding of very low safety significance was identified.

Introduction: A Green finding of very low safety significance and associated NCV of TS 5.7.2 was identified by NRC inspectors for failure to barricade, lock or continuously guard entrances to an area with dose rates greater than 1000 millirem per hour, measured 30 centimeters from the source.

Description: On January 24, 2008, NRC inspectors identified that access to the under-vessel area in the drywell, a Locked High Radiation Area (LHRA), did not have adequate controls to prevent inadvertent entry. Specifically, the access point known as the "key-way" did not have an adequate barricade to prevent entry. Licensee surveys indicated that locations under-vessel were greater than 1000 millirem per hour, measured 30 centimeters from the source. The licensee had posted the entrance as a LHRA and placed a flashing light at that entrance but a barricade was not in place. The key-way entrance is located on 723' elevation of the drywell where the Control Rod Drive (CRD) tracks penetrate the concrete under-vessel area. This access point is used by personnel to enter and exit the area and move equipment including CRDs in and out during a refueling outage.

On January 24, 2008, work was conducted under-vessel to remove a local power range monitor (LPRM) and the LPRM became stuck. Radiation Protection Technicians (RPTs) provided continuous coverage of the activities and the LHRA barricade was removed to provide access for workers and equipment. When the LPRM became stuck, work was stopped to formulate a recovery plan. The workers secured equipment and moved out of the area. The RPTs involved communicated the need to secure the area with an appropriate barricade and flashing lights; however, the barricade (rope barrier) was not physically positioned to obstruct inadvertent entry. The Radiation Protection first line supervisor (RP FLS) failed to independently ensure the task was completed properly. Consequently, the rope was not placed to function as an adequate barricade.

Additionally, the RP Staff determined that a ventilation plenum also provided access to the under-vessel area. Consequently, the RP FLS directed RPTs to post two ventilation doors, accessible from the 737 elevation, as LHRAs when the LPRM became stuck. The RP FLS did not know if there were actually LHRA conditions due to the stuck LPRM, but wanted to control the area as a conservative measure. The RPTs posted and placed flashing lights on the doors but did not lock the doors because locks with LHRA key cores were not available at the Drywell Control Point or the RP office on that shift. The RP FLS completed a request form for Approval for High Radiation Area Deviations as allowed by procedure RP-AA-460 under certain conditions to use a barrier and red flashing light in lieu of locking the area. The request was approved by the Duty RP Manager in the Outage Control Center. However, in accordance with the procedure and as required by technical specifications, the Duty RP Manager should not have approved the request because doors existed which could have been locked. Instead, the area should have been guarded until the LHRA lock became available. As a result, the key-way was not properly barricaded and the two ventilation plenum doors were not locked for several hours until identified by the inspectors.

<u>Analysis</u>: The inspectors determined that the lack of an adequate barricade at the key-way and the failure to lock two plenum doors could allow unauthorized entry into the under vessel-area and represents a performance deficiency because the licensee failed to meet TS requirements. In accordance with IMC 0612, the inspectors determined that the finding was more than minor because it was associated with the Occupational Radiation Safety Cornerstone Program/Process attribute and affected the cornerstone objective of ensuring worker health and safety from exposure to radiation. Specifically, failure to barricade the key-way access and lock the two ventilation plenum doors that provided an alternate pathway into the LHRA could allow workers to enter the under vessel area without authorization, resulting in unintended dose. The finding was evaluated using the SDP in IMC-0609 Appendix C for the Occupational Radiation Safety Cornerstone. The finding was determined to be of very low safety significance (Green) because it did not involve ALARA planning, was not associated with an overexposure, there was not a substantial potential for a worker overexposure and the licensee's ability to assess worker dose was not compromised.

This finding had a cross-cutting aspect in the area of human performance, work practices because the licensee did not appropriately follow procedures that resulted in a failure to properly control access to a LHRA (H.4(b)).

This issue was entered into the licensee's corrective action program (CAP) (IR 726499) in a timely manner and the evaluation of the issue was comprehensive and thorough relative to regulatory impact on station technical specifications and 10 CFR Part 20 compliance. Licensee immediate corrective actions included the establishment of an adequate barricade to the under-vessel "key-way" and locking both doors to the ventilation plenum area. Access to the RCA was suspended for the individuals involved with the incident. The licensee conducted an analysis of the extent of condition of all HRAs and LHRAs in the plant. These areas were walked down for compliance by zone owners, the Clinton Radiation Protection Manager (RPM) and the RPM from another Exelon Station. No other violations were identified. Additionally, a root cause analysis was performed by station personnel not involved in the incident.

<u>Enforcement</u>: TS 5.7.2 requires that areas in which an individual could receive a deep dose equivalent ≥1000 millirem in one hour (at 30 cm), shall be provided with locked or continuously guarded doors to prevent unauthorized entry. Additionally, if these areas are located within large areas, such as reactor containment, where no enclosure exists for enabling locking, or that are not continuously guarded, and where no lockable enclosure can be reasonably constructed around the individual area, the area shall be barricaded and conspicuously posted, and a flashing light shall be activated as a warning device.

Contrary to the above, on January 24, 2008, NRC inspectors identified two doors at the drywell 743 elevation that provided access to the under-vessel area (an area with dose rates >1000 millirem per hour) and an area that also allowed under-vessel access through the key-way that were not adequately barricaded. Since the finding is of very low safety significance and had been entered into the corrective action system as Corrective Action Program report (IR 726499), the associated violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy **(NCV 05000461-2008002-07)**.

.3 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed a sample of the licensee's self-assessments, audits, Licensee Event Reports, and Special Reports related to the access control program to verify that identified problems were entered into the corrective action program for resolution.

The inspectors reviewed corrective action reports related to access controls and high radiation area radiological incidents (non-PIs identified by the licensee in high radiation areas <1R/hr). Staff members were interviewed and corrective action documents were reviewed to verify that follow-up activities were being conducted in an effective and timely manner commensurate with their importance to safety and risk-based on the following:

- Initial problem identification, characterization, and tracking;
- Disposition of operability/reportability issues;
- Evaluation of safety significance/risk and priority for resolution;
- Identification of repetitive problems;
- Identification of contributing causes;
- Identification and implementation of effective corrective actions;
- Resolution of NCVs tracked in the corrective action system; and
- Implementation/consideration of risk-significant operational experience feedback.

The inspectors evaluated the licensee's process for problem identification, characterization, and prioritization, and verified that problems were entered into the corrective action program and resolved. For repetitive deficiencies and/or significant individual deficiencies in problem identification and resolution, the inspectors verified that the licensee's self-assessment activities were capable of identifying and addressing these deficiencies.

These reviews constitute three samples as defined in Inspection Procedure 71121.01-5.

b. Findings

No findings of significance were identified.

.4 Job-In-Progress Reviews

a. Inspection Scope

The inspectors observed the following jobs that were being performed in radiation areas, airborne radioactivity areas, or high radiation areas for observation of work activities that presented the greatest radiological risk to workers:

- Inservice Inspection Inside the Drywell Bio-shield;
- Drywell Scaffolding and Permanent Shielding Installation;
- Fuel Movement and Refuel Floor Work;
- Safety Relief Valve Removal and Replacement; and
- Drywell Flex Hose Replacement.

The inspectors reviewed radiological job requirements for these activities including RWP requirements and work procedure requirements, and attended ALARA job briefings.

Job performance was observed with respect to these requirements to determine whether radiological conditions in the work area were adequately communicated to workers through pre-job briefings and postings. The inspectors also determined if radiological controls were adequate including required radiation, contamination, and airborne surveys for system breaches; radiation protection job coverage which included audio and visual surveillance for remote coverage; and contamination controls.

The inspectors reviewed high radiation work areas with significant dose rate gradients to evaluate dosimetry placement and assure effective monitoring of exposure to personnel. There was no work involving significant dose rate gradients conducted during the on-site inspection.

These reviews constitute three samples as defined in Inspection Procedure 71121.01-5.

b. Findings

No findings of significance were identified.

.5 High Risk-Significant, High Dose Rate High Radiation Area (HRA) and Very High Radiation Area (VHRA) Controls

a. Inspection Scope

The inspectors held discussions with the Radiation Protection Manager and the Outage Manager during the refueling outage (RFO-15) concerning high dose rate/high radiation area and VHRA controls and procedures, including procedural changes that had occurred since the last inspection, in order to determine whether any procedure modifications could substantially reduce the effectiveness and level of worker protection.

The inspectors discussed with RP supervisors the controls that were in place for special areas that had the potential to become very high radiation areas during certain plant operations, to determine if these plant operations required communication beforehand with the RP group, so as to allow corresponding timely actions to properly post and control the radiation hazards.

The inspectors conducted plant walkdowns to determine the adequacy of the posting and locking of entrances to high dose rate HRAs, and VHRAs.

These reviews constitute three samples as defined in Inspection Procedure 71121.01-5.

2. Findings

No findings of significance were identified.

.6 Radiation Worker Performance

a. Inspection Scope

During job performance observations, the inspectors evaluated radiation worker performance with respect to stated radiation protection work requirements and evaluated whether workers were aware of the significant radiological conditions in their workplace, the RWP controls and limits in place, and that their performance had accounted for the level of radiological hazards present.

The inspectors reviewed radiological problem reports, which found that the cause of the event was due to radiation worker errors to determine if there was an observable pattern traceable to a similar cause, and to determine if this perspective matched the corrective action approach taken by the licensee to resolve the reported problems. These problems, along with planned and taken corrective actions were discussed with the Radiation Protection Manager.

These reviews constitute two samples as defined in Inspection Procedure 71121.01-5.

b. Findings

No findings of significance were identified.

.7 Radiation Protection Technician Proficiency

a. Inspection Scope

During job performance observations, the inspectors evaluated RPT performance with respect to radiation protection work requirements and evaluated whether they were aware of the radiological conditions in their workplace, the RWP controls and limits in place, and if their performance was consistent with their training and qualifications with respect to the radiological hazards and work activities.

The inspectors reviewed ten radiological problem reports which found that the cause of the event was RPT error to determine if there was an observable pattern traceable to a similar cause, and to determine if this perspective matched the corrective action approach taken by the licensee to resolve the reported problems.

These reviews constitute two samples as defined in Inspection Procedure 71121.01-5.

b. Findings

No findings of significance were identified.

2OS2 As-Low-As-Is-Reasonably-Achievable (ALARA) Planning And Controls (71121.02)

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed plant collective exposure history, current exposure trends, ongoing and planned activities in order to assess current performance and exposure challenges. This included determining the plant's current 3-year rolling average for collective exposure in order to help establish resource allocations and to provide a perspective of significance for any resulting inspection finding assessment.

The inspectors reviewed the outage work scheduled during the inspection period and associated work activity exposure estimates for the following work activities, which were likely to result in the highest personnel collective exposures:

- Inservice Inspection Inside the Drywell Bio-shield;
- Drywell Scaffolding and Permanent Shielding Installation;
- Fuel Movement and Refuel Floor Work;
- Safety Relief Valve Removal and Replacement; and
- Drywell Flex Hose Replacement.

This inspection constitutes two samples as defined in Inspection Procedure 71121.02-5.

b. Findings

No findings of significance were identified.

.2 Radiological Work Planning

a. Inspection Scope

The inspectors evaluated the licensee's list of work activities ranked by estimated exposure that were in progress and reviewed the following work activities of highest exposure significance:

- Inservice Inspection Inside the Drywell Bio-shield;
- Drywell Scaffolding and Permanent Shielding Installation;
- Fuel Movement and Refuel Floor Work;
- Safety Relief Valve Removal and Replacement; and
- Drywell Flex Hose Replacement.

For these activities, the inspectors reviewed the ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements in order to verify that the licensee had established procedures and engineering and work controls that were based on sound radiation protection principles in order to achieve occupational exposures that were ALARA. This also involved determining that the licensee had reasonably grouped the radiological work into work activities, based on historical precedence, industry norms, and/or special circumstances.

This inspection constitutes two samples as defined in Inspection Procedure 71121.02-5.

b. Findings

No findings of significance were identified.

.3 Verification of Dose Estimates and Exposure Tracking Systems

a. Inspection Scope

The inspectors reviewed the assumptions and bases for the current annual collective exposure estimate including procedures, in order to evaluate the licensee's methodology for estimating work activity-specific exposures and the intended dose outcome. Dose rate and man-hour estimates were evaluated for reasonable accuracy.

The licensee's process for adjusting exposure estimates or re-planning work, when unexpected changes in scope, emergent work or higher than anticipated radiation levels were encountered, was evaluated. This included determining that adjustments to estimated exposure (intended dose) were based on sound radiation protection and ALARA principles and not adjusted to account for failures to control the work. The frequency of these adjustments was reviewed to evaluate the adequacy of the original ALARA planning process.

This inspection constitutes two samples as defined in Inspection Procedure 71121.02-5.

b. Findings

No findings of significance were identified.

.4 Job Site Inspections and ALARA Control

a. Inspection Scope

The inspectors observed the following jobs that were being performed in radiation areas, airborne radioactivity areas, or high radiation areas for observation of work activities that presented the greatest radiological risk to workers:

- Inservice Inspection Inside the Drywell Bio-shield;
- Drywell Scaffolding and Permanent Shielding Installation;
- Fuel Movement and Refuel Floor Work;
- Safety Relief Valve Removal and Replacement; and
- Drywell Flex Hose Replacement.

For these activities, the licensee's use of engineering controls to achieve dose reductions was evaluated to verify that procedures and controls were consistent with the licensee's ALARA reviews, that sufficient shielding of radiation sources was provided for and that the dose expended to install/remove the shielding did not exceed the dose reduction benefits afforded by the shielding.

This inspection constitutes one sample as defined in Inspection Procedure 71121.02-5.

b. Findings

No findings of significance were identified.

.5 Radiation Worker Performance

a. Inspection Scope

Radiation worker and RPT performance was observed during work activities being performed in radiation areas, airborne radioactivity areas, and high radiation areas that presented the greatest radiological risk to workers. The inspectors evaluated whether workers demonstrated the ALARA philosophy in practice by being familiar with the work activity scope and tools to be used, by utilizing ALARA low dose waiting areas and that work activity controls were being complied with. Also, radiation worker training and skill levels were reviewed to determine if they were sufficient relative to the radiological hazards and the work involved.

This inspection constitutes one sample as defined in Inspection Procedure 71121.02-5.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Unplanned Scrams per 7000 Critical Hours

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Scrams per 7000 Critical Hours performance indicator (PI) for the period from the First Quarter 2007 through the Fourth Quarter 2007 to determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in Revision 5 of the Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator Guideline," were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, event reports, and NRC Inspection reports for the period of January 2007 through December 2007 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Specific documents reviewed are described in the Attachment to this report.

This inspection constitutes one Unplanned Scrams per 7000 Critical Hours sample as defined in Inspection Procedure 71151.

b. Findings

No findings of significance were identified.

.2 Unplanned Power Changes

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Power Changes PI. The inspectors reviewed licensee data related to unplanned power changes greater than twenty percent from the First Quarter 2007 through the Fourth Quarter of 2007. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in Revision 5 of the Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator Guideline," were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, event reports and NRC Inspection reports for the period of January 2007 through December 2007 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Specific documents reviewed are described in the Attachment to this report.

This inspection constitutes one Unplanned Power Changes sample as defined in Inspection Procedure 71151.

b. Findings

No findings of significance were identified.

.3 Scram with Complications

a. Inspection Scope

The inspectors sampled licensee submittals for the Scram with Complications PI. The inspectors reviewed licensee data related to scrams with complications from the First Quarter 2007 through the Fourth Quarter of 2007. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in Revision 5 of the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, event reports, and NRC Inspection reports for the period of January 2007 through December 2007 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Specific documents reviewed are described in the Attachment to this report.

This inspection constitutes one Scrams with Complications sample as defined in Inspection Procedure 71151.

b. Findings

No findings of significance were identified.

.4 Safety System Functional Failures

a. Inspection Scope

The inspectors sampled licensee submittals for the Safety System Functional Failures PI. The inspectors reviewed licensee data related to safety system functional failures from the First Quarter 2007 through the Fourth Quarter of 2007. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in Revision 5 of the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, event reports and NRC Inspection reports for the period of January 2007 through December 2007 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Specific documents reviewed are described in the Attachment to this report.

This inspection constitutes one Safety System Functional Failures sample as defined in Inspection Procedure 71151.

b. Findings

No findings of significance were identified.

.5 Drill/Exercise Performance (71151-05)

a. Inspection Scope

The inspectors sampled licensee submittals for the Drill/Exercise PI for the period from the Third Quarter 2007 through the Fourth Quarter 2007. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, were used. The inspectors reviewed the licensee's records associated with the performance indicator to verify that the licensee accurately reported the indicator in accordance with relevant procedures and the NEI guidance. Specifically, the inspectors reviewed licensee records and processes including procedural guidance on assessing opportunities for the PI; assessments of PI opportunities during predesignated control room simulator training sessions, performance during the 2007 biennial exercise, and performance during other drills. Specific documents reviewed are described in the Attachment to this report.

This inspection constitutes one Drill/Exercise sample as defined in Inspection Procedure 71151-05.

b. Findings

No findings of significance were identified.

.6 Emergency Response Organization (ERO) Drill Participation

a. Inspection Scope

The inspectors sampled licensee submittals for the ERO Drill Participation PI for the period from the Third Quarter 2007 through the Fourth Quarter 2007. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99-02, Revision 5, were used. The inspectors reviewed the licensee's records associated with the performance indicator to verify that the licensee accurately reported the indicator in accordance with relevant procedures and the NEI guidance. Specifically, the inspectors reviewed licensee records and processes including procedural guidance on assessing opportunities for the PI; performance during the 2007 biennial exercise and other drills; and revisions of the roster of personnel assigned to key emergency response organization positions. Specific documents reviewed are described in the Attachment to this report.

This inspection constitutes one ERO Drill Participation sample as defined in Inspection Procedure 71151-05.

b. Findings

No findings of significance were identified.

.7 Alert and Notification System

a. Inspection Scope

The inspectors sampled licensee submittals for the Alert and Notification System (ANS) PI for the period from the Third Quarter 2007 through the Fourth Quarter 2007. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI 99-02, Revision 5, were used. The inspectors reviewed the licensee's records associated with the performance indicator to verify that the licensee accurately reported the indicator in accordance with relevant procedures and the NEI guidance. Specifically, the inspectors reviewed licensee records and processes including procedural guidance on assessing opportunities for the PI and results of scheduled ANS operability tests. Specific documents reviewed are described in the Attachment to this report.

This inspection constitutes one Alert and Notification System sample as defined in Inspection Procedure 71151-05.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

From January 14, 2008, through January 17, 2008, the inspectors conducted a review of the corrective actions for two condition reports (CR) associated with hydraulic piping for the reactor recirculation flow control valve actuator. Specifically, the inspectors reviewed the associated CRs, Action Request (AR) 205618 and AR 693914, and the licensee's design basis documents related to the hydraulic power unit (HPU) piping including the drawings, calculations, design/installation specifications, Updated Final Safety Analysis Report (UFSAR), and the TSs. The inspectors also performed field walkdowns for review of as-built configuration.

b. Findings

Failure to Evaluate HPU Piping for Impact with Containment Atmosphere Monitoring Line

Introduction: The inspectors identified a Green NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions," regarding the licensee's failure to adequately address CRs AR 205618, and AR 693914. Specifically, in evaluating whether the "A" HPU piping was adequately supported, the licensee did not adequately address that the as-built support configuration had not been properly verified from a design standpoint. In particular, the licensee did not consider the safety-related classification of a nearby containment/drywell atmosphere monitoring tubing and that this tubing could be impacted if the HPU piping failed during a postulated design basis seismic event. Hence, the licensee did not implement the additional evaluation/calculations required to demonstrate the HPU piping met more stringent design requirements and was adequately supported.

Description: Licensee CR AR 205618, originated on March 2, 2004, stated that the piping to vent valves 1B33-F324A and 1B33-F327A did not have hangers to restrain their movements, and that the circulation unit 1B33-C34A was not restrained. The CR also stated that the pipes would move 12 inches or more side to side with a slight push. Per assignment AR 205618-02, a walkdown performed during refueling outage C1R10 on February 20, 2006, identified two missing hangers on each of lines 1RR35A ½ and 1RR38A ¾. Assignment AR 205618-02 also recommended restoring the piping configuration to the design or to correct design documentation. Assignment AR 205618-03 completed on July 27, 2006, stated calculations 1SRR02 and 1SRR04 were issued via engineering change (EC) 361723 to reconcile the discrepancies between the as-built configuration and the design, thus completing the item. EC 361723 and the calculation updates concluded that deletion of the missing hangers was approved under the as-built verification program because the approved as-built piping drawings reflected the installed configuration, and based on that, the calculation updates were treated as administrative changes. However, the licensee's staff did not find and did not perform calculations that specifically addressed adequacy of the piping configuration with a reduced number of supports. Subsequent to the above actions, a second CR, AR 693914, was originated on November 2, 2007, stating concerns identical to those in AR 205618. Condition report AR 693914 was dispositioned without further evaluations based on documentation for AR 205618.

The inspectors reviewed the licensee's design basis documents related to the HPU including the drawings, calculations, design / installation specifications, UFSAR, and the TSs. The inspectors determined that HPUs and associated hydraulic lines did not perform any safety-related function. Per Table 3.2-1 of the UFSAR, the flow control valve actuator, HPU, circulation unit, and the interconnected piping all have a non-safety and non-seismic classification, have no quality assurance requirements, and ASME B31.1, "Power Piping," was the applicable design code for the piping system. The original design drawing for the HPU piping, MO7-1072 Sheet 2, detailed 3 supports on each of the 1-inch lines and 4 supports on each of the smaller lines. The as-built drawing, BA-MO7-1072 Sheet 2, detailed only two supports on each line. The design calculations reflected the original design drawing, were based on the ASME B31.1 code, and did not evaluate seismic loads.

The HPU and the subject lines were located in the containment building, outside the drywell. The inspectors performed a field walkdown of the piping and the surrounding area and verified that the four lines run from the drywell penetration IMD 55 to the HPU. Two of the four hydraulic fluid lines were 1-inch nominal pipe diameter, while the other two were ¾ inch and ½-inch nominal pipe diameter. The 1-inch lines also supported a line mounted circulation unit. The installed configurations matched the as-built drawing, BA-MO7-1072 Sheet 2, having only two supports on each line. There was no calculation to support this as-built configuration. During the walkdown, the inspectors identified that ½ inch diameter tubing for the safety-related containment atmosphere monitoring system was routed in close proximity to the subject HPU hydraulic lines. The inspectors did not identify any other safety-related component in proximity to the HPU piping system that could be adversely affected by direct impact or hydraulic fluid spill due to a line break.

The licensee demonstrated that the ½ inch and ¾ inch HPU lines were very flexible, but these lines were physically located below the safety-related tubing, and therefore, their failure or seismic deflection would not impact the safety-related tubing. However, the inspectors determined that in case of a line break or excessive deflection during a seismic event, there was a potential for the 1-inch HPU lines or the circulation unit that was supported by these lines to impact and damage the safety-related tubing so as to prevent it from performing its safety-related function. The inspectors also walked down the HPU piping for the opposite train and did not identify a similar concern there, because the piping was routed differently. Based on Section 3.2.1 of the UFSAR, which specified requirements for non-seismic components located in Seismic Category I areas, an evaluation was required to ensure the HPU piping system would not adversely affect the safety-related containment monitoring tubing. No such evaluation was identified by the licensee as part of the original design or corrective actions for the more recent CRs.

Upon identification of the above deficiency, the licensee performed additional walkdowns witnessed by the inspectors that measured available clearances between the HPU system and the safety-related tubing. The licensee also performed additional calculations to analyze the as-built piping system including design basis seismic requirements. The licensee's preliminary results based on conservative calculations indicated that the design basis requirements were met. The inspectors reviewed the licensee's preliminary calculations and concluded that the existing plant configuration had sufficient clearance between the HPU system and the safety-related tubing. The licensee also entered the issue in the corrective action program under AR 723620 with recommended actions to complete the seismic clearance calculation for the HPU system, and revise the existing HPU piping calculations to incorporate the as-built configuration.

Analysis: The inspectors determined that failure to perform an evaluation for potential impact of the HPU piping with the safety-related containment atmosphere monitoring system tubing during a design basis event was a performance deficiency warranting a significance evaluation. The inspectors further determined that the issue was within the licensee's ability to foresee and correct, because the licensee staff, during disposition of AR 205618 and AR 693914, had the opportunity and would have reasonably been expected to identify the safety-related tubing located in proximity of the HPU piping and to evaluate the HPU piping for the design basis requirements. Inspectors determined that the finding was more than minor because it was associated with the Barrier Integrity Cornerstone and affected the cornerstone objective of maintaining functionality of containment due to the potential impact on the safety-related containment atmosphere monitoring system which was needed to monitor and to take actions to mitigate challenges to containment integrity.

In accordance with IMC 0609, "Significance Determination Process," the inspectors used the screening worksheets Tables 1 through 4 provided in IMC 0609.04, "Phase 1 – Initial Screening and Characterization of Finding." In Table 2, under Barrier Integrity column, the Containment Barrier degraded box was checked based on degraded hydrogen control. The Containment Barrier box was also checked under Item 7 in Table 3b to enter the Containment Barrier column in Table 4a. All boxes in this column were answered "No" to screen the finding as Green. In particular, the licensee's preliminary results based on conservative calculations indicated that the design basis requirements were met, and hence field modifications were not necessary.

The primary cause of this failure was related to the cross-cutting component of Human Performance, Resources (Item H.2.(c) of IMC 305) because licensee personnel failed to maintain complete, accurate, and up-to-date design documents. Specifically, the licensee did not adequately update the calculations to reflect the as-built configuration and the design basis requirements.

Enforcement: 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions," states, in part, that measures shall be established to assure that conditions adverse to quality, such as deficiencies, deviations, and non-conformances are promptly identified and corrected.

Contrary to the above, on January 17, 2007, as part of corrective actions for AR 205618 and AR693914 questioning whether HPU piping was adequately supported, the licensee did not adequately correct a condition adverse to quality, that the as-built support configuration had not been adequately verified from a design standpoint. In particular, the licensee did not consider the safety-related classification of nearby containment/drywell atmosphere monitoring tubing and that this tubing could be impacted if the HPU piping failed during a postulated design basis seismic event. Hence, the licensee did not implement the additional evaluation/calculations required to demonstrate the HPU piping met more stringent design requirements and was adequately supported. However, because this violation was of very low safety significance and was entered into the licensee's Corrective Action Program, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000461/2008002-06)**. The licensee entered the finding into the Corrective Action Program as AR 723620.

.2 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

Inspectors reviewed licensee's use of Operating Experience (OE) from Braidwood regarding an emergency diesel generator (EDG) fuel oil line leak. Action Requests AR 743814, AR 756789, and AR 753793 were reviewed to ensure any adverse trends were identified and addressed and that the licensee's identification of any problems was complete, accurate, and timely and that the consideration of extent of condition review, generic implications, common cause, and previous occurrences were adequate.

b. Findings

No findings of significance were identified. During the course of their EDG walkdowns, the licensee identified several interference points on their three divisions of EDG equipment. These concerns and others were identified in the initial AR 743814 and were documented for specific work requests in three subsequent Action Requests. The licensee concluded that these issues did not pose a challenge to EDG safety functions or mission times. In reaching this conclusion, an appropriate level of expert input was obtained through Exelon Corporate and on-site personnel. Corrective actions also made adequate use of available OE.

4OA5 Other

.1 Quarterly Resident Inspector Observations of Security Personnel and Activities

a. Inspection Scope

During the inspection period, the inspectors conducted the following observations of security force personnel and activities to ensure that the activities were consistent with licensee security procedures and regulatory requirements relating to nuclear plant security. These observations took place during both normal and off-normal plant working hours.

- Multiple tours of operations within the Central and Secondary Security Alarm Stations;
- Tours of selected security towers/security officer response posts;
- Direct observation of personnel entry screening operations within the plant's Main Access Facility, and observation of security personnel performing weapons inventory.

These quarterly resident inspector observations of security force personnel and activities did not constitute any additional inspection samples. Rather, they were considered an integral part of the inspectors' normal plant status review and inspection activities.

b. Findings

No findings of significance were identified.

4OA6 Management Meetings

.1 Exit Meeting Summary

On April 11, 2008, the inspectors presented the inspection results to Mr. Mark Kanavos, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspector asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

.2 Interim Exit Meetings

Interim exit meetings were conducted for:

- Inservice Inspection (IP 71111.08), with Mr. B. Hanson and other members of licensee management at the conclusion of the inspection on January 18, 2008. The licensee confirmed that none of the potential report input discussed was considered proprietary.

- Identification and Resolution of Problems (71152) inspection performed to review corrective actions associated with condition reports AR 205618 and AR 693914, with Mr. Kearney and other members of the Clinton staff on January 17, 2008. Mr. Kearney acknowledged the finding presented, and Clinton staff indicated that no proprietary information was provided to the inspectors.

- Access Control to Radiologically Significant Areas and ALARA Planning and Controls Inspection with Mr. B. Hanson, Site Vice President on January 25, 2008.

- Emergency Preparedness inspection with Mr. F. Kearney on March 21, 2008.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

F. Kearney, Site Vice President
M. Kanavos, Plant Manager
R. Schenck, Work Management Director
G. Vickers, Radiation Protection Director
J. Gackstetter, Regulatory Assurance Manager
R. Frantz, Regulatory Assurance Representative
M. Hiter, Access Control Supervisor
M. Friedmann, Acting Regulatory Assurance Director
C. VanDerburgh, Nuclear Oversight Manager
J. Domitrovich, Maintenance Director
D. Schavey, Operations Director
J. Rappeport, Acting Chemistry Manager
J. Lindsay, Training Manager
C. Williamson, Security Manager
R. Peak, Site Engineering Director
T. Chalmers, Shift Operations Superintendent
J. Miller, Engineering
J. Peterson, Regulatory Assurance
D. Anthony, NDE Level III
K. Appel, Corporate Mid-West Emergency Preparedness Manager
J. Sznquist, Corporate Emergency Preparedness Specialist
D. VanAken, Emergency Preparedness Coordinator
M. Baigh, ISI Engineer
H. Do, Corporate ISI Engineer, Cantera

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened:

05000461/2008002-01	NCV	Failure to follow approved fire protection program procedures concerning control of Transient Combustible Material
00500461/2008002-02	FIN	The licensee discovered that the wrong component was installed in the B Turbine Driven Reactor Feed Pump oil pressure sensing logic.
00500461/2008002-03	NCV	During the performance of NRC final drywell closeout, the inspectors noted that foreign material/housekeeping sock had not been removed from the drywell floor drains.
00500461/2008002-04	URI	As-Found Leakage Through Shutdown Service (SX) Valve 1SX014A.
00500461/2008002-05	URI	Changes to ERO On-Shift and Augmentation Staffing Levels and Position Titles.
05000461/2008002-06	NCV	Failure to Evaluate Hydraulic Power Unit Piping for Impact with Containment Atmosphere Monitoring Line (Section 4AO2.b)

05000461/2008002-07	NCV	Failure to Barricade and Lock a Locked High Radiation Area; Section 2OS1

Closed:

05000461/2008002-01	NCV	Failure to follow approved fire protection program procedures concerning control of Transient Combustible Material
00500461/2008002-02	FIN	The licensee discovered that the wrong component was installed in the B Turbine Driven Reactor Feed Pump oil pressure sensing logic.
00500461/2008002-03	NCV	During the performance of NRC final drywell closeout, the inspectors noted that foreign material/housekeeping sock had not been removed from the drywell floor drains.
05000461/2008002-06	NCV	Failure to Evaluate Hydraulic Power Unit Piping for Impact with Containment Atmosphere Monitoring Line (Section 4AO2.b)
05000461/2008002-07	NCV	Failure to Barricade and Lock a Locked High Radiation Area; Section 2OS1

Discussed:

None

LIST OF DOCUMENTS REVIEWED

The following is a partial list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspector reviewed the documents in their entirety, but rather that selected sections or portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

1R04 Equipment Alignment Issue Reports:

CPS 3310.01V001; Reactor Core Isolation Cooling Valve Lineup
CPS 3310.01V002; Reactor Core Isolation Cooling Instrument Valve Lineup
CPS 3310.01E001; Reactor Core Isolation Cooling Electrical Lineup
CPS 3313.01V001; Low Pressure Core Spray Valve Lineup
CPS 3313.01E001; Low Pressure Core Spray Electrical Lineup
CPS 3313.01; Low Pressure Core Spray (LPCS)
CPS 3309.01E001; High Pressure Core Spray Electrical Lineup
CPS 3309.01V001; High Pressure Core Spray Valve Lineup
CPS 3309.01V002; High Pressure Core Spray Instrument Valve Lineup
CPS 3309.01; High Pressure Core Spray (HPCS)

1R05 Fire Protection Issue Reports:

1893.04M101 Rev. 4; 707 to 712 Auxiliary: LPCS Pump Room Prefire Plan

1R08 Inservice Inspection Activities (IP 71111.08)

-AR00446834; Review of Dresden NER for Impact on Core Spray Piping Flaw Analysis at Clinton; dated January 27, 2006
-AR00516332; Update ISI Code Boundary Schematics Listing; dated August 3, 2006
-AR00463544; C1R10 LL Recommendations for ISI Improvements; dated March 8, 2006
-AR00606949; Missed Weld Inspections on RHR B Pump Cooler; March 21, 2007
-GE-ADM-1062; Procedure for Determining and Documenting Examination Requirements for Risk-Informed Inservice Inspections; Revision 0
-GE-PDI-UT-1; PDI Generic Procedure for the Ultrasonic Examination of Ferritic Pipe Welds; Revision 5
-GE-UT-321; Procedure for Manual Ultrasonic Examination of Nozzle Inner Radii and Bore (Non-Appendix VIII); Revision 0
-GE-UT-605; Procedure for the Performance of Straight Beam Examinations; Revision 3
-GE-MT-100; Procedure for Magnetic Particle Examination (Dry Particle, Color Contrast or Wet Particle, Fluorescent); Revision 6
-GE-VT-101; Procedure for VT-1 Examination; Revision 2
-ER-AA-335-005; Radiographic Examination; Revision 3
-ER-AA-335-025; Oversight of Vendor NDE Activities; Revision 3

1R12 Maintenance Effectiveness Issue Reports:

CR 441902; Degraded Seal Ring Possible Chemical Affects (In 2006)
CR 858384; TDRFP Thermst Bearing Trip
CR 593279; MDRFP Procedures with Different Caution Notes

CR 615751; EPM Sensor Failure
CR 709338; Question about MDRFP Power Sources
CR 722094; 1B21-F065A Did not close from MCR 50 Turns. To manually close
CR 722747; 1A&52E-3D Computer Point Lead Found Lifted WO# 01084251
CR 724304; Bore Scope of MOV 1B21 F065A
CR 724310; Bore Scope of MOV 1B21 F065B
CR 732178; Hydraulic Pump Running Continously
CR 735245; RPV Level Oscillations During FW Evolution
CR 756259; Feed Water Level Control Needs Troubleshooting (or) Thinning
CR 757408; Computer Point C34NA004 Indicates Eratically
Unavailability Status: Rolling 24 months
Reliability Criteria Status: Rolling 24 months
Condition Monitoring Criteria Status: Rolling 24 months

1R13 Maintenance Risk Assessments and Emergent Work Control Issue Reports:

AR 00755275; RR B Seal Pressure Fluctuations
AR007755223; Clarification on Required ADS Air bottle Pressure Limits

1R19 Post-Maintenance Testing Issue Reports:

01046145-01; PSFW135 – Replace TDRFP 1B Press SW Diaphragms or Entire SW
AR 00732626; 1FW01PB – RR FCV Runback Due to B TDRFP Malfunction
CPS 8801.01; Instrument Calibration
CPS8801.01D001; Single-Input Instrument Calibration Data Sheet
MA-AA716-012 Revision 10; Post-Maintenance Testing
00752267; CAT ID Info Extracted by Passport in Printed WO Incomplete
00966204; EQ-CL044-07 Overhaul Damper Actuator

1R22 Surveillance Testing Issue Reports:

AR 00687982; Unable to Calibrate 1E22R504
AR 00733675; 1E22R504: High Pressure Core Spray Suction Pressure Guage Overranging
9051.01; High Pressure Core Spray Pump & WLP Operability
WO 01075968; 9051.01R22 OP High Pressure Core Spray Pump & WTR Leg Pump Oper (RCIC STRG TANK)
WO 01101718; 9080.03A23 OP DG 1C Oper – Monthly Test
9051.01; High Pressure Core Spray Pump & High Pressure Core Spray Water Leg Pump Operability

1EP2 Alert and Notification System Evaluation Issue Reports:

-00582326; 1RIX-PR043 New TSC PING Chart Recorder Not Advancing, January 23, 2007
-00606488; New TSC Heating Not Tied to Backup Power, March 20, 2007
-00489433; ERO Vehicle Not Available for Emergency Response, May 12, 2006
-00528634; ERO Vehicle Batteries Dead, September 2006
-00576637; ERO Generator Missing, January 8, 2007
-00518714; NOS ID'd Potential E-Plan Non-Compliance for Notification, August 10, 2006
-00509408; NOS 2Q06 Rating of Yellow for Emergency Preparedness, July 14, 2006
-00625448; NOS Id'D NUREG 0654 Requirements for HP Drills Not Met, May 4, 2007
-00546423; NEW TSC HVAC Failed Pressure/Air Flow Test, October 19, 2006

-00509059; 2006 Exercise NARS Notification Exceeds 15 Minutes, July 13, 2006
-00481085; NOS ID'd Inadequate Tracking of ERO Qualifications, April 20, 2006
-00510859; NOS ID'd ERO Performance Shortfalls, July 19, 2006
-00710637; EP PI Source Document Issues, December 12, 2007
-00504841; Emergency Notification Siren Common Cause Analysis, June 29, 2006
-00565489; Offsite Emergency Sirens Out-of-Service Due to Weather, December 5, 2006
-00568870; Clinton Station Alert Notification System Reached 25% Outage, December 13, 2006
-00543307; Common Cause Analysis Needed for On-call Emergency Response Organization Response, October 12, 2006
-00711880; Duty ERO Member Incorrectly Responds to Dialogics Questions
-00573883; Radiation Protection Challenged Minimum Staffing Requirements, December 30, 2006
-Clinton 2006 Health Physics Drill Evaluation Report, June 16, 2006
-Clinton 2006 Medical/Health Physics Drill Evaluation Report, September 15, 2006
-Clinton 2007 Medical/Health Physics Drill Evaluation Report, May 18, 2007
-Clinton 2007 Health Physics Drill Evaluation Report, August 8, 2007
-Assembly and Accountability Drill Memo; Subject: 2006 CPS Assembly and Accountability Drill, March 7, 2007
-Clinton 2006 Environmental Phase Monitoring Drill Evaluation Report
-FEMA Approved Design Report; Illinois, August 23, 1985
-Emergency Services, "An Offsite Alert and Notification System for the Clinton Power Station"
-Exelon Semi-Annual Siren Report, January 1, 2006 to June 30, 2006
-Exelon Semi-Annual Siren Report, July 1, 2006 to December 31, 2006
-Exelon Semi-Annual Siren Report, January 1, 2007 to June 30, 2007
-Clinton Warning System Maintenance and Operational Annual Maintenance Report, June 28, 2006
-Clinton Warning System Maintenance and Operational Annual Maintenance Report, July 16, 2007
-Clinton Siren Daily Operability Reports, January 2, 2006 to December 29, 2006
-Clinton Siren Daily Operability Reports, January 2, 2007 to December 31, 2007
-Clinton siren Daily Operability Reports, January 2, 2008 to February 29, 2008
-Clinton Siren Monthly Operability Reports, 2007
-Clinton Siren Monthly Operability Reports, 2008
-Clinton Offsite Siren Test Plan, December 2006
-Common Cause Analysis 504841; Emergency Notification Siren Test Failures, July 31, 2006
-ERO Augmentation Drill memo; Subject: September 16, 2004 Call-In (Drive-In) Augmentation Drill Results, October 18, 2004
-ERO Call-In Augmentation Monthly Drill Reports, April 2006 – December 2006
-ERO Call-In Augmentation Quarterly Drill Reports, January 2007 – December 2007
-Clinton Station Augmentation Drill, March 18, 2008
-Individual Performance Tracking Records, January 2007 – March 2008
-Clinton Power Station Emergency Response Organization Roster, March 14,2008
-Clinton Power Station ERO Pool Roster, March 2008
-Random Sample of 21 ERO Individual EP Training Records, March 2008
-NRC EP Baseline Program Inspection Readiness Self-Assessment, February 19, 2008
-Self-Assessment; Clinton Power Station NRC EP Baseline, February 19, 2008
-Report 696824; Program Inspection Readiness
-NOSA-CPS-06-03; Nuclear Oversight Clinton Power Station 2006 Emergency Preparedness 50.54(t) Audit, April 26, 2006
-NOSA-CPS-07-04; Nuclear Oversight Clinton Power Station 2007 Emergency Preparedness 50.54(t) Audit

-Clinton 2007 NRC Graded Exercise Evaluation Report, September 2, 2007
-NRC Drill/Exercise Performance Indicator Records, July 2007 – December 2007
-NRC Emergency Response Organization Drill Participation Records, July 2007 – December 2007
-Clinton Power Station 2006 Full Scale Drill Evaluation Reports, May 23, 2006, August 1, 2006 and December 6, 2006
-Clinton Power Station 2007 Performance Indicator Drill Evaluation, February 23, 2007
-Clinton Power Station 2007 Full Scale Drill Evaluation Report, May 11 – June 7, 2007
-EP-AA-1000; Exelon Nuclear Standardized Radiological Emergency Plan, Revision 19
-TA-AA-113; ERO Training and Qualification, Revision 10
-EP-AA-112-110-F-06; Midwest ERO Notification or Augmentation, Revision G
-EP-AA-122-1001; Drill and Exercise Scheduling, Development and Conduct, Revision 9
-EP-AA-1003; Radiological Emergency Plan Annex for Clinton Station; Section 2.1; On-Shift Emergency Response Organization Assignments, Table B-1, Revision 11

2OS1 Access Control to Radiologically Significant Areas

- AR 722144; Electronic Dosimeter Dose Alarm and Personnel Contamination Event, 1/14/08
- AR 724361; Area Released By Radiation Protection Found to be Contaminated, 1/18/08
- AR 724384; Blue Radiologically Controlled Area Gloves Discovered outside of the Radiologically Controlled Area, 1/18/08
- AR 724728; Personnel Contamination Event; 1/20/08
- AR 716499; NRC Identified Locked High Radiation Area Violation, 1/24/08
- RWP 10007241; C1R11 Drywell – Inservice-Inspection Inside Bio-Shield, Rev 2
- RWP 10007248; C1R11 Drywell – Scaffolding, Rev 1
- RWP 10007249; C1R11 Drywell – Shielding, Rev 2
- RWP 10007250; C1R11 Drywell – Permanent Shielding, Rev 1
- RWP 10007261; C1R11 Drywell – Flex Hoses, Rev 2
- RWP 10007315; C1R11 Refuel Cavity Work, Rev 1
- RP-AA-401; Operation ALARA Planning and Controls, Rev 8

2OS2 As-Low-As-Is-Reasonably-Achievable Planning and Controls

- Assignment 563533-04; ALARA Planning and Controls, 11/11/07
- AR 723365; Nuclear Oversight Identified Unacceptable Radworker Practices, 1/17/08
- AR 723957; Two Level 1 Personnel Contaminations From the Same Location, 1/18/08
- AR 724435; Contaminated Individual 828' Refuel Floor, 1/18/08
- RWP 10007241; C1R11 Drywell – Inservice-Inspection Inside Bio-Shield, Rev 2
- RWP 10007248; C1R11 Drywell – Scaffolding, Rev 1
- RWP 10007249; C1R11 Drywell – Shielding, Rev 2
- RWP 10007250; C1R11 Drywell – Permanent Shielding, Rev 1
- RWP 10007261; C1R11 Drywell – Flex Hoses
- RWP 10007315; C1R11 Refuel Cavity Work, Rev 1
- RP-AAA-400; ALARA Program, Rev 4
- RP-AA-401; Operation ALARA Planning and Controls

4OA2 Problem Identification and Resolution Corrective Action Documents

-AR 205618; Unrestrained Piping; 2/20/2007.
-AR 693914; 1B33F324A: Still Unrestrained Piping; dated November 2, 2007.

Corrective Action Documents Generated as a Result of NRC Inspection

-IR 723620; NRC Inspection Finding – Potential NCV; dated January 17, 2008.

Drawings

-Drawing MO7-1072, Sheet 2; Reactor Recirculation Piping 2” and Under; Revision F.
-Drawing MO7-1072, Sheet 3; Reactor Recirculation Piping 2” and Under; Revision E.
-Drawing BA-MO7-1072, Sheet 2; Reactor Recirculation Piping 2” and Under; Revision FG.
-Drawing BA-MO7-1072, Sheet 2; Reactor Recirculation Piping 2” and Under; Revision EG.
-Drawing MO3-1102, Sheet 1; Mechanical Piping Penetration Schedule - Drywell; Revision Z.
-Drawing MO3-1102, Sheet 2; Mechanical Piping Penetration Schedule - Drywell; Revision Y.
-Drawing CM-926; Containment Building Containment Monitoring System Piping; Revision 8.

Calculations

-Calculation No. 1SRR01; Calcs for 1RR01; Revision 0.
-Calculation No. 1SRR02; Containment Building Simplified Piping Analysis; Revision 0A.
-Calculation No. 1SRR03; Calcs for 1RR03; Revision 0.
-Calculation No. 1SRR04; Containment Building Simplified Piping Analysis; Revision 0A.

Engineering Changes

-ECR 364057; Unrestrained Piping for RR Flow Control Valves; dated September 22, 2004.
-EC361723; Issue Calculation to Reflect As-built Configuration for Non-Safety-related RR Piping; dated August 1, 2006.

Vendor Documents

-22A4607; Recirculation System Hydraulic Equipment Installation Requirements (GE); Rev 2.

LIST OF ACRONYMS USED

AC	Alternating Current
ADAMS	Agencywide Documents Access and Management System
AR	Assignment Report
AR	Action Request
ASME	American Society of Mechanical Engineers
CFR	Code of Federal Regulations
CR	Condition Report
DC	Direct Current
DG	Diesel Generator
DRP	Division of Reactor Projects
EC	Engineering Change
ERO	Emergency Response Organization
FSAR	Final Safety Analysis Report
FW	Feedwater
GE	General Electric
HPCS	High Pressure Core Spray
HPU	Hydraulic Power Unit
IP	Inspection Procedure
ISI	Inservice-Inspection
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Inspection Report
IR	Issue Report
ISI	Inservice Inspection
MDRFP	Motor-Driven Reactor Feed Pump
MIC	Microbiologically Induced Corrosion
MOV	Motor-Operated Valve
MT	Magnetic Particle Examination
NCV	Non-Cited Violation
NDE	Nondestructive Examination
NEI	Nuclear Energy Institute
NOS	Nuclear Oversight Agency
NRC	U.S. Nuclear Regulatory Commission
OE	Operating Experience
OPS	Outage Safety Plan
PARS	Publicly Available Records
PI	Performance Indicator
PM	Planned or Preventative Maintenance
RCIC	Reactor Core Isolation Cooling
RFP	Reactor Feed Pump
RH	Residual Heat Removal
RHR	Residual Heat Removal
RPV	Reactor Pressure Vessel
SBLC	Standby Liquid Control
SDP	Significance Determination Process
SER	Safety Evaluation Report
SLC	Standby Liquid Control
SSCs	Structures, Systems and Components
SW	Service Water

SX	Shutdown Service Water
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VT	Ultransonic Examination
WO	Work Order
WRGM	Wide Range Gas Monitor