May 1, 2007

Mr. Christopher M. Crane
President and Chief Nuclear Officer
Exelon Nuclear
Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: CLINTON POWER STATION
NRC PROBLEM IDENTIFICATION AND RESOLUTION
INSPECTION REPORT 05000461/2007007

Dear Mr. Crane:

On March 23, 2007, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection of problem identification and resolution at your Clinton Power Station. The enclosed inspection report documents the inspection findings which were discussed on March 23, 2007, with Mr. Kearney and other members of your staff.

This inspection was an examination of activities conducted under your license as they relate to the identification and resolution of problems, compliance with the Commission's rules and regulations and with the conditions of your operating license. Within these areas, the inspection involved selected examination of procedures and representative records, observations of activities, and interviews with personnel.

On the basis of the sample selected for review, the team concluded that, in general, problems were properly identified, evaluated, and corrected. One finding of very low safety significance (Green) was identified during this inspection. The finding involved the improper securing of radiation protection stanchions in containment within the suppression pool swell zone. This finding was also determined to be a violation of NRC requirements. However, because of its very low safety significance and because it has been entered into your corrective action program, the NRC is treating this finding as a non-cited violation (NCV), in accordance with Section VI.A.1 of the NRC's Enforcement Policy.

If you contest the subject or severity of an NCV in this report, you should provide a response with the basis for your denial, within 30 days of the date of this inspection report, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001, with copies to the Regional Administrator, Region III; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC 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 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 Nos. 50-461
License Nos. NPF-62

Enclosure: Inspection Report No. 05000461/2007007
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
Senior Vice President - Nuclear Services
Vice President - Operations Support
Vice President - Licensing and Regulatory Affairs
Manager Licensing - Clinton Power Station
Senior Counsel, Nuclear, Mid-West Regional Operating Group
Document Control Desk - Licensing
Assistant Attorney General
Illinois Emergency Management Agency
State Liaison Officer, State of Illinois
Chairman, Illinois Commerce Commission

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

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

Docket Nos. 50-461
License Nos. NPF-62

Enclosure: Inspection Report No. 05000461/2007007
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
Senior Vice President - Nuclear Services
Vice President - Operations Support
Vice President - Licensing and Regulatory Affairs
Manager Licensing - Clinton Power Station
Senior Counsel, Nuclear, Mid-West Regional Operating Group
Document Control Desk - Licensing
Assistant Attorney General
Illinois Emergency Management Agency
State Liaison Officer, State of Illinois
Chairman, Illinois Commerce Commission

DOCUMENT NAME: C:\FileNet\ML071220208.wpd
☐ Publicly Available ☐ Non-Publicly Available ☐ Sensitive ☐ Non-Sensitive
To receive a copy of this document, indicate in the concurrence box "C" = Copy without attach/encl "E" = Copy with attach/encl "N" = No copy

OFFICE	RIII							
NAME	MRing:dtp							
DATE	05/01/07							

OFFICIAL RECORD COPY

Letter to Christopher M. Crane from Mark A. Ring dated 04/   /07

SUBJECT: CLINTON POWER STATION
NRC PROBLEM IDENTIFICATION AND RESOLUTION
INSPECTION REPORT 05000461/2007007

DISTRIBUTION:
TEB
RAG1
SPS1
RidsNrrDirsIrib
GEG
KGO
GLS
RML2
SAM9
SRI Clinton
CAA1
LSL (electronic IR's only)
C. Pederson, DRS (hard copy - IR's only)
DRSIII
DRPIII
PLB1
TXN
ROPreports@nrc.gov (inspection reports, final SDP letters, any letter with an IR number)

U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-461
License Nos:	NPF-62
Report No:	05000461/2007007
Licensee:	AmerGen Energy Company, LLC
Facility:	Clinton Power Station
Location:	Clinton, Illinois
Dates:	March 5, 2007, through March 23, 2007
Inspectors:	A. Barker, Project Engineer - Team Lead D. Tharp, Resident Inspector J. Jandovitz, Reactor Engineer S. Mischke, Illinois Emergency Management Agency
Approved by:	Mark A. Ring, Chief Branch 1 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000461/2007007; 03/05/2007 - 03/23/2007; Clinton Power Station; Identification and Resolution of Problems.

The inspection was conducted by region-based inspectors, the resident inspectors at the Clinton Power Station and the onsite IEMA inspector. One finding of very low safety significance (Green) was identified which involved an associated non-cited violation (NCV). 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 3, dated July 2000.

Identification and Resolution of Problems

In general, the station identified issues and entered them into the corrective action program (CAP) at the appropriate level. In addition, issues that were identified from operating experience reports and instances where previous corrective actions were ineffective or inappropriate were also entered into the CAP. The inspectors concluded that issues were properly prioritized and generally evaluated well. The inspectors determined that conditions at the Clinton Power Station were conducive to identifying issues. The licensee staff at Clinton was aware of and generally familiar with the CAP and other station processes, including the Employee Concerns Program, through which concerns could be raised. One finding of very low safety significance (Green) was identified during this inspection.

A. Inspector-Identified and Self-Revealed Findings

Cornerstone: Barrier Integrity

- Green. The inspectors identified an NCV of 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, And Drawings,” for failure to assure that activities affecting quality be accomplished in accordance with prescribed documented instructions, procedures, or drawings. Contrary to procedure CPS 1019.05, “Transient Equipment/Materials,” step 8.5.3, four radiation protection (RP) stanchions were secured to the 755' elevation in the containment building with ty-raps instead of metal grating clips. The licensee removed the stanchions, performed a walkdown of containment to ensure there were no other improperly installed stanchions, and entered this performance deficiency into the CAP for resolution.

  This finding was associated with the Barrier Integrity Cornerstone. The finding was more than minor because the finding was viewed as a precursor to a significant event. If left uncorrected, the stanchions could become missiles during a suppression pool swell event, potentially damaging containment isolation valves. The inspectors assessed the significance of this finding as very low safety significance (Green) because the finding did not represent an actual open pathway in the physical integrity of the reactor containment. The finding was associated with cross-cutting aspect P.1(c), Thoroughly Evaluate Problems, of the problem identification and resolution cross-cutting area, in that, the licensee's initial reviews of the issue failed to evaluate the potential design basis impact. (Section 4OA2.a)

B. Licensee-Identified Violations

No findings of significance were identified.

REPORT DETAILS

4. OTHER ACTIVITIES

4OA2 Problem Identification and Resolution

a. Assessment of the Corrective Action Program

(1) Inspection Scope

The inspectors reviewed documentation for the past 3 years including: NRC inspection report findings, selected corrective action documents, licensee self-assessments, Nuclear Oversight (NOS) audits, operating experience reports and human performance initiatives to determine if problems were being identified and entered into the corrective action program (CAP) at the proper threshold. CAP implementation, metrics, and status, and departmental performance indicators were also reviewed and discussed with the station staff.

The inspectors also reviewed procedures, inspection reports, and corrective action documents to verify that identified issues were appropriately characterized and prioritized in the CAP. Evaluations documented in condition reports (CRs) or issue reports (IRs) were evaluated for appropriateness of depth and thoroughness relative to the significance or potential impact of each issue. Inspectors attended management meetings to observe the assignment of CR categories for current issues and to observe the review of root, apparent, and common cause analyses, and corrective actions for existing CRs.

In addition, the inspectors reviewed past inspection results, selected CRs and IRs, root cause reports, and common cause evaluations to verify that corrective actions, commensurate with the safety significance of the issues, were specified and implemented in a timely manner. The inspectors evaluated the effectiveness of corrective actions. The inspectors also reviewed the licensee's corrective actions for NCVs documented in NRC inspection reports in the past 3 years.

This inspection constitutes one biennial sample of problem identification and resolution as defined by Inspection Procedure 71152.

(2) Assessment

Identification of Issues

The inspectors concluded, in general, that the station identified issues and entered them into the CAP at the appropriate level. The inspectors' review of operating experience reports identified that the licensee was appropriately including the issues into the CAP. The licensee also used the CAP to document instances where previous corrective actions were ineffective or were inappropriately closed. The following paragraphs provide a specific review of the identification of issues on the reactor core isolation cooling (RCIC) system.

An expanded 5 year review was conducted by the inspectors on the RCIC. The initial scope of the licensee's search of the CAP and work order databases for a 5-year period resulted in approximately 1300 documents being identified. From the inspectors' initial screening, approximately 100 issue reports/work orders were selected for further review and subdivided into specific categories. Through the inspectors' review of the screened issue report/work order categories, and follow-up discussion with the licensee staff, approximately 20 issue reports were selected as an expanded sample. The issue statement that was developed for the review was focused on RCIC turbine/governor oil leaks impacting RCIC functionality.

During the 5-year review period there were numerous issue reports related to RCIC turbine/governor oil leaks with a peak of approximately 10 issue reports in 2004 to a low of two issue reports in 2006. In all cases, RCIC operability was evaluated and determined to be unaffected based on minimal oil leak rate. For one occurrence, documented by IR 177868, compensatory actions were initiated by Operations to monitor turbine/governor oil leakage once a shift until the leaks were repaired. Additionally, evaluation EC 350620 performed for IR 240608 documented that minimal oil leaks/seepage did not affect the functionality/operability of the RCIC system. The identification of RCIC turbine/governor oil leaks since about 2004 within the CAP facilitated the required corrective actions, and a reduction in the number of oil leaks on the system.

Through the additional review of the identification of issues, the inspectors developed an observation regarding a specific occurrence of degrading pipe wall thickness of a service water supply line. This issue was not identified as a condition adverse to quality in the CAP. The following paragraphs provide this observation.

<u>Service Water Supply Line Degrading Pipe Wall Thickness</u>

In 2001, the licensee performed ultrasonic wall thickness examinations on the service water supply lines to the spent fuel pool. These areas were on the redundant A and B lines and the pipe sections were identified as 1SX12AA-2.5" and 1SX12AB-2.5". The examinations noted wall loss on both lines and both areas were re-scheduled for examination in approximately 1 year. In September 2002, these areas were again examined. The wall thickness determined on the A line was 0.139 inches, and on the B line the wall thickness was 0.130 inches. Both of these lines were approaching the calculated code minimum wall thickness of 0.080 inches, and the evaluation recommended replacement of both lines within 6 months. The evaluation also stated that an inspection program ensures the wall thickness would not exceed the code minimum wall.

In late 2003, from additional examinations, the wall thickness low reading on the A line was 0.0100 inches, and on the B line the low reading was also 0.0100 inches. An evaluation was completed on the A line results, and EC 346745 concluded that this component would stay above the code minimum wall criteria for 5 more months, and was therefore acceptable until the scheduled replacement in February 2004. No corresponding evaluation was conducted on the B line results. The B line pipe section was not scheduled for replacement until February 2005. In early 2005, the B line was examined, with the lowest wall thickness determined to be 0.067 inches which was below the code minimum wall thickness of 0.080 inches. Additional code wall thickness analysis was contained in EC 346745 that showed the B line wall thickness determined by the 2005 examination was acceptable to allow replacement by February 2005. The B line 2003 examination results that determined degrading wall thickness were not identified as a condition adverse to quality in the CAP. However, the B line wall thickness was being monitored in a periodic examination program and was replaced before exceeding the EC 346745 wall thickness criteria of 0.037 inches.

Prioritization and Evaluation of Issues

The inspectors' observations of the Station Ownership Committee (SOC) concluded that for some IRs, additional follow-up activities were assigned that extended the time period for issue disposition within the organization. Using LS-CL-125-1001, "SOC Observation Form," the review activities by SOC for some IRs appear to be similar to the warning flag pertaining to "spends time reviewing issue not for condition, but for cause." However, none of the issues that were assigned the additional follow-up resulted in an inappropriate prioritization based on significance. Examples of SOC action taken were to assign work requests, evaluations, and/or corrective action to specific departmental groups. The inspectors observed the Management Review Company (MRC) function in an oversight role of the SOC. For example, the MRC changed the SOC recommended action of some issues based on committee dialogue and additional station awareness of the issue. The MRC performed grading of investigative CAP products to provide feedback on product quality to the sponsoring manager.

The IRs that were observed being reviewed by the SOC were also observed being reviewed by the MRC in their oversight role. The MRC member dialogue in the review of root, apparent, and common causes was informative, and provided feedback to the staff on implementing the CAP. The inspectors concluded that issues were properly prioritized and generally evaluated well.

However, the inspectors developed observations regarding the prompt operability and reportablility basis of some IRs that were reviewed by SOC. The following paragraphs provide these observations.

Operability Basis Not Documented

During the SOC review of March 9, 2007, IRs 601242, "UT on Piping Spool 1SX13AA-8 Identifies Wall Loss," and 601262, "Cells 14 and 20 Resistance Above Acceptable Limit," did not have a prompt operability basis documented for either IR. The attending SOC members agreed to assign to the SOC engineering representative an action to obtain additional information for these IRs that would enhance their informative content. This action was to be completed on day shift. The inspectors at the conclusion of the SOC review meeting questioned why these IRs were not reviewed for prompt operability by operations shift management within the same shift or by the oncoming shift in accordance with procedure LS-AA-120, "Issue Identification And Screening Process." The SOC operations representative referred to procedure OP-AA-108-115, for operability determinations that allow for prompt operability decisions to be made within 24 hours. These IRs, as written, did not contain sufficient documented information to be complete in describing the associated conditions. That is the basis why engineering accepted action to enhance the IRs' informative content. Further discussion with the SOC operations representative and the operations director, resulted in the inspectors realizing that the prompt operability reviews were completed for each IR by operations shift management. However, operations shift management did not document in the IRs the current operability basis and the additional communications that were held with the engineering staff to conclude prompt operability. IR 601586 was generated to identify the difference between procedures OP-AA-108-115 and LS-AA-120 for prompt operability decisions. In addition, IRs 601242 and 601262, were updated to document the current operability basis that had been previously determined.

Reportable Basis Objective Evidence

During the SOC review of March 19, 2007, of IR 605619, "Effluent Wet Well Overflows At 14' 2" In Secondary Lagoon," the inspectors concluded that the IR's reportability basis lacked objective evidence. The reportability basis, in part, reads, "The last time the level in the effluent wet well was observed was at 2130 on 3/17/07. The water was identified to be slightly overflowing in the overflow pipe at 0955 on 3/18/07. There is no evidence that any overflow occurred prior to midnight 3/18/07. Hence, all discharge occurred during the current NPDES discharge week." The attending SOC members did not question this basis that was determined by operations shift and chemistry management. The inspectors discussed the conclusion that "there is no evidence that any overflow occurred prior to midnight 3/18/07," with the chemistry manager. The chemistry manager provided additional information, not documented in the original IR, on the communications held between his staff and operations. The chemistry manager also stated that a non-licensed operator (NLO) had observed at 0100 on 3/18/07 the wet well level was 1/4 to 1/16 inches from overflowing. The information provided by the chemistry manager resulted in the inspectors realizing that objective evidence did exist supporting the reportability basis. In addition, IR 605619 was updated to document the objective evidence.

(3) Finding

Procedure Non-Compliance

Introduction: The inspectors identified a Green NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, And Drawings," for failure to assure that activities affecting quality be accomplished in accordance with prescribed documented instructions, procedures, or drawings. Contrary to procedure CPS 1019.05, "Transient Equipment/Materials," step 8.5.3, four radiation protection (RP) stanchions were secured to the 755' elevation in the containment building with ty-raps instead of metal grating clips. Specifically, step 8.5.3 states, "to ensure that stanchions used in containment do not become a missile hazard the requirements for securing stanchions in Appendix D shall be followed." Appendix D identifies the design of the stanchions to be used and references Drawing M26-1000-01AJ for the grating clips.

Description: The four RP stanchions were used to post a contamination area around a fire hose station on the 755' elevation. The RP stanchions were approximately 3 feet high with a support base of 12 by 12 inches, and weighed approximately 15 pounds. The RP stanchions were approximately 6 feet apart making a square boundary around the fire hose station. The RP stanchions provided a holder for a nylon rope boundary around the contamination zone. The RP stanchions were located near the outer wall of the containment within the suppression pool swell zone. The swell zone is the area affected by the suppression pool during a reactor blow down (i.e., depressurization) to the suppression pool during a loss of coolant accident (LOCA). The RP stanchions were in-place since between May 26, 2006, and June 30, 2006, until they were removed on March 16, 2007.

The improper securing of these RP stanchions was identified by the resident inspectors on March 15, 2007, during a tour of the containment building with licensee staff, and determined to be a performance deficiency. The licensee generated IR 604868 to document this issue on March 16, 2007. The Station Ownership Committee (SOC) closed IR 604868 on March 19, 2007, to actions already taken, contamination area de-posted and the RP stanchions removed, and to the planned action of re-emphasizing the requirements of procedure CPS 1019.05 to the radiation protection department. The Management Review Committee did not challenge the SOC documented actions for closure during its March 20, 2007, review of IR 604868. On March 21, 2007, the inspectors specifically identified to the licensee staff that IR 604868 did not include an evaluation of the station’s compliance to its design basis during the time period the RP stanchions were in-place within the suppression pool swell zone. The licensee generated IR 607316 to document this issue on March 22, 2007.

The licensee staff performed evaluation EC 365177, ”Review of Design Basis of RP Stanchions in Containment.” The evaluation calculated the impact force on the bottom of a solid base RP stanchion from the suppression pool swell to be 1317 lbs. Since the ty-wraps were not able to withstand the force of the pool swell, a walk down was done to determine equipment that could have been hit by the RP stanchions, had the stanchions become missiles. The equipment identified by the licensee’s walkdown that could affect containment isolation were valves 1FC007, the Fuel Pool Cooling and Cleanup (FC) Containment Outlet Inboard Valve, and 1FP053, the Fire Protection (FP) Containment Inboard Isolation Valve. These motor operated valves are normally open and are inboard containment isolation valves. They automatically close on the Group 8 isolation signals of high drywell pressure or reactor level 2. Since during a pool swell event, the non-conforming RP stanchions could have damaged the flexible conduit or motor operators, these valves had the potential to fail open (i.e., as is), fail their design basis, and not close on a valid isolation signal. The licensee’s evaluation conservatively assumed that the missiles created could impinge on the two containment isolation valves and prevent their containment isolation function.

Because the worst-case pool swell event is the result of a large line break LOCA in the drywell, the high drywell pressure isolation would be expected to occur. An isolation signal would close both the inboard and outboard isolation valves in both the FC and FP lines. Therefore, the licensee’s evaluation identified that the systems’ functions were not impacted by the possible failure of these valves, because the operable containment outboard isolation valves, 1FC008 and 1FP054, would have provided for containment isolation. In addition, the fire protection outboard containment isolation valve 1FP054 is maintained normally closed, so the design basis of the containment penetration was maintained.

Containment isolation is required following a LOCA-Loss of Offsite Power (LOOP) event. Since the two valves, 1FC007 and 1FP053, are inboard isolation valves, powered from Division 2, containment isolation can be assured if the Division 1 Diesel Generator (DG) was operable during the time the RP stanchions were in-place. If during the installation of the RP stanchions, a Division 1 DG were inoperable, such as, during a maintenance outage, then the outboard containment isolation valves would not have been able to automatically close. In this set of circumstances, the containment isolation function would not have been able to be completed. The licensee determined that the Division 1 DG was out of service on September 18, 2006, for 6 hours, and October 2-5, 2006, for 79.2 hours for a maintenance outage. In addition, the DG was taken out of service for 10 to 30 minutes each month for routine pre-start checks. Therefore, when the Division 1 DG was out of service, the station did not meet General Design Criteria 54, which requires piping systems penetrating the containment to have redundant isolation.

Analysis: The inspectors concluded that the performance deficiency was more than minor because the finding is viewed as a precursor to a significant event because if left uncorrected, the stanchions could become missiles during a suppression pool swell event, potentially damaging containment isolation valves. The inspectors reviewed Appendix B to Inspection Manual Chapter 0612 and determined that this finding was required to be evaluated by the Significance Determination Process due to its impact on the Barrier Integrity Cornerstone objective to provide reasonable assurance that physical design barriers (i.e., functionality of containment) protect the public from radio nuclide releases caused by accidents or events. The inspectors assessed the significance of this finding as very low safety significance (Green) because the finding did not represent an actual open pathway in the physical integrity of the reactor containment. The inspectors determined that the finding was associated with a cross-cutting aspect in the area of Problem Identification and Resolution, Corrective Action Program because the licensee failed to thoroughly evaluate problems such that the resolutions address causes and extent of condition (P.1(c)). Specifically, the licensee failed to thoroughly evaluate the impact on the design basis when the improper use of RP stanchions was identified through IR 604868.

Enforcement: 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, And Drawings,” states, in part, 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 with these instructions, procedures, or drawings. Contrary to the above and procedure CPS 1019.05, “Transient Equipment/Materials,” step 8.5.3, four radiation protection (RP) stanchions were secured to the 755' elevation in the containment building with ty-raps instead of metal grating clips. Because this failure to comply with 10 CFR Part 50, Appendix B, Criterion V, is of very low safety significance and has been entered into the licensee’s corrective action program as IRs 604868 and 607316, this violation is being treated as an NCV, consistent with Section VI.A of the Enforcement Policy **(NCV 05000461/2007007-01)**. Corrective actions for this

NCV included licensee removal of the RP stanchions. Evaluation EC 365177 documented the design basis review. A licensee walkdown was done which confirmed that there were no other incorrectly anchored stanchions in the containment.

Effectiveness of Corrective Action

In general, the licensee corrective actions for the samples reviewed were appropriate, and appeared to have been effective. The inspectors determined that the licensee generated IRs when a corrective action was identified which was either inadequate or inappropriate. However, the inspectors developed an observation regarding the development of corrective actions for a human performance deficiency that did not consider human factors associated with the nearly identical hardware. The following paragraphs provide this observation.

Error Precursor Corrective Actions

The Quick Human Performance Investigation (QHPI) performed for installing the incorrect carrier gas on the H_2/O_2 monitoring subsystem documented by IR 594756 identified two “error precursors.” One was related to hardware, the N_2 & He carrier gas bottles are essentially identical, and the other was related to human performance, complacency/lack of self checks or peer checks. The Exelon manual for preparing QHPIs, LS-AA-125-1003, “Apparent Cause Evaluation Manual,” directs the development of “corrective actions that address the identified error precursors.”

The QHPI focused only on corrective action development for the human performance deficiency, and did not consider human factors associated with the nearly identical hardware. The inspectors held a discussion with the QHPI investigator on the rationale for only addressing the human performance issue and not the hardware issue. The rational was that maintenance activities have been successfully performed at the facility where “nearly” identical items could potentially be mistakenly installed. The QHPI investigator and SOC concluded that this was an isolated human performance occurrence, and applying additional controls to the hardware issue were not warranted. This information supporting the decision to not consider human factors was not documented in the QHPI. Issue Report 608300 was generated to identify this issue.

b. Assessment of the Use of Operating Experience

(1) Inspection Scope

The inspectors reviewed the licensee’s program for handling operating experience (OPEX). Specifically, the inspectors reviewed the implementing procedure, attended corrective action program meetings to observe the use of OPEX, reviewed OPEX evaluated by the station and reviewed selected 2007 OPEX Daily Event Reports.

(2) Assessment

No findings of significance were identified.

In general, OPEX information was being well utilized at the station. The inspectors observed that Exelon fleet internal OPEX and industry OPEX were discussed by licensee staff to support review activities and CAP investigations. During licensee staff interviews, the inspectors identified that the use OPEX was being considered during daily activities.

The inspectors verified that industry events were entered into the CAP and were evaluated for impact at the facility. Specifically, two industry events were reviewed for licensee action, the recent jet pump nozzle cracks at Duane Arnold and flow accelerated corrosion on reactor vessel drain lines. Both of these industry events were entered into the licensee's CAP. Examinations were conducted on the Clinton reactor vessel drain line in response to the industry OPEX.

The inspectors also verified that significant 2006 industry OPEX was addressed in the licensee's CAP. The OPEX for this review included topics such as, safety related electrical power, internal flooding, pressure boundary degradation, environmental qualification, extended power uprate, circuit breakers, foreign material exclusion, human errors and safety related cooling. The inspector's review concluded that 80-plus IRs were related to the significant industry OPEX topical areas.

However, the inspectors developed an observation regarding OPEX that was not effectively applied in station procedures. The following paragraph provides this observation.

EPRI-NMAC Report 1007460, "Terry Turbine Maintenance Guide"

In September 2004, the licensee identified an enhancement opportunity to incorporate EPRI-NMAC Report 1007460, "Terry Turbine Maintenance Guide," into existing preventive maintenance and surveillance procedures. The licensee's engineering, maintenance, and operations departments reviewed this report and determined that the changes were not significant and incorporated the "Maintenance Guide" as a reference only in the maintenance procedures. In February 2006, the reactor core isolation cooling (RCIC) governor valve stem linkage setup was performed using the original vendor manual guidance, and not the EPRI-NMAC Terry Turbine Maintenance Guide. In May 2006, the licensee started the RCIC turbine for surveillance testing and was unable to control turbine flow at 620 gallons per minute (g.p.m.) as directed by the surveillance procedure. Operators observed RCIC flow to rise to 681 g.p.m. when the turbine was started. This was higher than the surveillance acceptable range of 606 to 620 g.p.m. Operations declared the RCIC turbine inoperable and conducted troubleshooting between May 10 and May 12, 2006. The licensee conducted an equipment apparent cause evaluation. The apparent cause determined that conducting the surveillance with the test return valves full open for in-service testing was incorrect. A contributing cause was the failure to incorporate the EPRI-NMAC Terry Turbine Maintenance Guide in the operations and maintenance procedures. This guide provided changes to the linkage adjustment and surveillance testing that would have prevented the problem. The licensee re-performed the RCIC governor valve setup, changed the surveillance procedure using the EPRI guidance, successfully completed the surveillance, and declared the RCIC system operable. In this example, failure to use the EPRI-NMAC Terry Turbine Maintenance Guide resulted in the unplanned unavailability of the RCIC turbine.

c. <u>Assessment of Self-Assessments and Audits</u>

(1) <u>Inspection Scope</u>

The inspectors reviewed selected focused area self-assessments (FASA), check-in self-assessments, and Nuclear Oversight (NOS) audits of the corrective action program, technical human performance, engineering design control and programs, maintenance, operations and system performance monitoring. The inspectors evaluated whether these audits and self-assessments were being effectively managed, were adequately covering the subject areas, and were properly capturing identified issues in the CAP. In addition, the inspectors also interviewed licensee staff regarding the implementation of the audit and self-assessment programs.

(2) <u>Assessment</u>

No findings of significance were identified.

The inspectors concluded that the self-assessments and NOS audits were generally critical and probing. Multi-discipline teams were utilized, when appropriate, to gain a broad perspective. The use of OPEX supported team preparations and scope development of the NOS audits. There were a number of deficiencies, recommendations and strengths identified across the spectrum of performance, including issues of improper CAP implementation. As appropriate, the self-assessment and NOS audit deficiencies were documented in the CAP.

The licensee performed Check-In Self-Assessment 284483, “System Performance Monitoring,” in May 2005. The self-assessment reviewed system performance monitoring with a focus on the effectiveness of system performance teams in meeting engineering management and policy expectations. The system performance monitoring teams selected were reviewed for various attributes, such as, cross-functional participation in quarterly meetings and walkdowns, senior management sponsor participation, publication of team results and integration of system performance improvement plans into system notebooks. Three self-assessment deficiencies were identified and entered into the CAP under separate IRs. The self-assessment identified deficiencies with system performance monitoring teams not holding meetings quarterly, the lack of senior management sponsor participation and inconsistent team member participation on the quarterly walkdowns.

The licensee performed NOS Audit NOSA-CPS-06-01, “Maintenance Functional Area,” in March 2006. One of the common audit deficiencies that was identified had fleet-wide applicability based on utilization of a standardized process. This deficiency involved the lack of corrective action being implemented for Exelon’s OPEX Nuclear Event Report (NER) BW-04-099, “Unclear Expectations for Work in the Area of Protected Equipment.”

Fleet-Wide actions designated for the NER response, IR 274947, included evaluation of the contractor in-process training and inclusion of the NER in contractor lessons learned tailgates. The licensee's evaluation resulted in the initiation of training request 04-1407. The nuclear employee in-processing training lesson plan was to be revised to include a definition of the protected equipment process and personnel expectations when encountering protected equipment signs. However, the training request was closed without the lesson plan being revised. The licensee generated IR 449636 during the audit for this issue.

d. Assessment of Safety-Conscious Work Environment

(1) Inspection Scope

The inspectors interviewed selected members of the Clinton station staff to determine if there were any impediments to the establishment of a safety conscious work environment. In addition, the inspectors discussed the implementation of the Employee Concerns Program (ECP) with the ECP Coordinators, and reviewed their 2006/2007 activities to identify any emergent issues or potential trends. Licensee programs to publicize the CAP and ECP programs were also reviewed. In addition, FASA 476076 conducted on the corrective action program in January 2007, was reviewed for ECP issues.

(2) Assessment

No findings of significance were identified.

The inspectors determined that the conditions at the Clinton station were conducive to identifying issues. The staff was aware of and generally familiar with the CAP and other station processes, including the ECP, through which concerns could be raised. Staff interviews identified that issues could be freely communicated to supervision, and that several of the individuals interviewed had previously initiated IRs. In addition, a review of the types of issues in the ECP indicated that site personnel were appropriately using the corrective action and employee concerns programs to identify issues. The inspectors interviewed the ECP Coordinators and concluded that the individuals were focused on ensuring all site individuals were aware of the program, comprehensive in their review of individual concerns, and used the corrective action and employee concerns programs to appropriately resolve issues.

The corrective action program FASA 476076 identified an ECP deficiency. The specific deficiency was that new employees were not meeting with an ECP coordinator in accordance with HR-AA-4000, "Employees Entering or Transferring Within Nuclear Stations," Revision 2. The licensee generated IR 587003 to document this deficiency. In response to IR 587003, human resources generated a list of new hires within the last 90 days. The inspectors interviewed approximately 50 percent of the new hires. These interviews revealed that the new hires had already been presented an ECP orientation by the ECP coordinators. Also, the new hires were aware of the corrective action and employee concerns programs through which issues could be identified to supervision.

4OA6 Management Meetings

Exit Meeting Summary

The inspectors presented the inspection results to Mr. Kearney and other members of the Clinton staff at an exit meeting on March 23, 2007. Mr. Kearney acknowledged the finding presented, and indicated that no proprietary information was provided to the inspectors.

ATTACHMENT: SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

F. Armetta, Engineering
T. Bostwick, Regulatory Assurance
D. Brendley, Regulatory Assurance
J. Butts, Nuclear Oversight
S. Clary, Engineering Programs Supervisor
A. Darelius, Nuclear Oversight
B. Dean, Maintenance
J. Domitrovich, Maintenance Director
G. Evars, Maintenance
J. Feeney, Nuclear Oversight
R. Frantz, Regulatory Assurance
B. Green, Radiation Protection
B. Hanson, Site Vice President
C. Hill, Work Management
M. Hundley, Operations
F. Kearney, Plant Manager
J. Lindsey, Training Director
G. Mosley, Operations Support/Services Manager
R. Peak, Site Engineering Director
F. Perryman, Nuclear Oversight
J. Peterson, Regulatory Assurance
J. Piatt, Project Manager
D. Schavey, Operations Director
R. Schenck, Business Operations Director
K. Scott, Regulatory Assurance Manager
W. Scott, Chemistry Manager
P. Smith, Nuclear Oversight
M. Stickney, Maintenance
J. Stovall, Outage Manager
R. Vickers, Radiation Protection Manager
J. Wernlinger, Operations
C. Williamson, Security Manager

Nuclear Regulatory Commission

M. Ring, Chief, Branch 1, Division of Reactor Projects

Illinois Emergency Management Agency

S. Mischke, IEMA Inspector

ITEMS OPENED, CLOSED, AND DISCUSSED

Items Opened

05000461/2007007-01	NCV	Procedure Non-Compliance

Items Closed

05000461/2007007-01	NCV	Procedure Non-Compliance

Items Discussed

None

LIST OF DOCUMENTS REVIEWED

The following is a list of licensee documents reviewed during the inspection. Inclusion of a document on this list does not imply that NRC inspectors reviewed the entire document, but, rather that selected sections or portions of the documents were evaluated as part of the overall inspection effort. In addition, inclusion of a document on this list does not imply NRC acceptance of the document, unless specifically stated in the body of the inspection report.

Issue Reports Related to NRC Findings

212295; Inappropriate closure of condition report corrective action; April 1, 2004
492994; NRC NCV 2006-02-01, Shutdown Cooling Header Leak-Off line; May 23, 2006
492997; NRC NCV 2006-02-02, Shutdown Service Water valve leak test; May 23, 2006
492999; NRC Finding 2006-02-03, C1R10 Dose not ALARA; May 23, 2006
201183; C1R09 Source Term; February 12, 2004
524365; Automatic Reactor Scram on Reactor High Water Level; August 28, 2006
557348; NRC Finding 2006-07-01, 8/27/06 Reactor Scram; November 13, 2006
368008; Entry into 4004.02, Loss of Vacuum; August 29, 2005
289643; Failed to properly reset logic during 9432.60; January 11, 2005
211372; Standby Liquid Control tank level indication trending down; March 28, 2004
213560; Standby Liquid Control air sparger valve found out of position; April 6, 2004
176490; Chunk of Rust found in Diesel Generator Air Start System check valve; September 19, 2003
210301; Division 1 Diesel Generator 'B' air receiver check valve leaking by; March 23, 2004
210859; Foreign Material found in check valve 1DG169; March 25, 2004
213491; Inadequate Work Order Closure Documentation; April 6, 2004
201824; Incorrect size fuse found installed in NSPS card; February 15, 2004

RCIC Turbine/Governor Oil

CPS Maintenance Standard MS-08; Lubrication Level of Rotating Equipment; Revision 20
"AutoTour" printout of 'C' Area Non-Licensed Operator Surveillance Rounds
Individualized Instructor Guide Module CC85101; Initial NLO Classroom Administrative Training; Revision 1
Lesson Plan LP85217-11; Reactor Core Isolation Cooling (RI); Revision 11
Non-Licensed Operator Certification Guide; RI-Reactor Core Isolation Cooling
EC-334968; RCIC Turbine Bearing Oil Level Was Found 3/16" Lower Than Minimum Standby Oil Level As Described In MS-08
EC-350620; RCIC Turbine Lube Oil System

Issue Reports:

91417; Unplanned LCO Entry, RCIC Inop Due to Low Oil Level; January 19, 2002
177868; Small Oil Accumulation at RCIC Governor; September 27, 2003
201817; Oil Soaked Insulation Susceptible to Fire-Heat/Steam Turbine; February 15, 2004
203984; RCIC Exhaust Insulation Oil Soaked; February 25, 2004
206031; Oil Film on RCIC Turbine Governor and Oil Bubbler Cocked; March 4, 2004
206097; RCIC Oil Leak; March 4, 2004
206163; Tracking CR For RCIC Oil Sight Glass; March 4, 2004

207833; Minor Oil Seepage At Outboard Oil Bubbler; March 11, 2004
214720; Oil Leak on RCIC Turbine; April 13, 2004
215332; Install New Insulation For RCIC Turbine-Oil Residue; April 16, 2004
240608; Oil Leak/Loose Nuts Discovered on RCIC Shaft Driven Oil Pump; July 31, 2004
241661; Identify And Fix Oil Seepage-RCIC Turbine Lube Oil System; August 4, 2004
264026; Slight Oil Leak From Underside Plug on 1E51-N580; October 15, 2004
314053; RCIC Servo For Governor Valve Leaking Oil; March 17, 2005
321272; 1E51C002: Multiple Minor Leaks on RCIC Turbine And Pump; April 5, 2005
329705; Generate WO For Remaining Oil Leaks on RCIC Turbine Skid; April 28, 2005
453581; 1E51C002: 2” Diameter Oil Line Identified For Potential Leak; February 14, 2006
489703; PMT Failure on RCIC Turbine Oil Filter Leak; May 12, 2006
563348; Minor Oil Leaks on Sight Glass And Governor Assembly; November 29, 2006
589461; Found RCIC Turbine And Governor Oil Below The Standby Band; February 9, 2007

Procedures

EI-AA-1; Employee Issues; Revision 1
EI-AA-101; Employee Concerns Program; Revision 6
EI-AA-100-1003; Employee Issues Advisory Committee Notification; Revision 0
EI-AA-101-1001; Employee Concerns Program Process; Revision 4
EI-AA-101-1002; Employee Concerns Program Trending Tool; Revision 3
LS-AA-115; Operating Experience; Revision 9
LS-AA-120, Issue Identification and Screening Process, Revision 6
LS-AA-125, Corrective Action Program Procedure, Revision 10
LS-AA-125-1001; Root Cause; Revision 5
LS-AA-125-1002; Common Cause; Revision 4
LS-AA-125-1003; Apparent Cause; Revision 6
LS-AA-125-1004; Effectiveness Review; Revision 2
LS-AA-126; Self-Assessment Program; Revision 5
LS-AA-126-1001; Focused Area Self-Assessments; Revision 4
MA-AA-716-040; Control of Portable Measurement and Test Equipment Program; Revision 3
OP-AA-102-102; General Area Checks and Operator Field Rounds; Revision 5
OP-AA-201-006; Control of Temporary Heat sources; Revision 3
QCOP 0010-02; Required Cold Weather Routines; Revision 22
QCOP 3900-06; Flushing Heat Exchanger Temperature Control Valve Bypass Lines; Revision 0
OP-AA-108-115; Operability Determinations; Revision 0
OP-AA-106-101-1006; Operational and Technical Decision Making Process; Revision 3
LS-AA-110; Commitment Management; Revision 4
QCOP 1000-31; RHR Service Water Venting; Revision 12
HU-AA-1101; Change Management; Revision 1
CC-MW-101; Engineering Change Requests; Revision 0
LS-AA-125-1005; Coding and Analysis Manual; Revision 5
LS-CL-125-1001; SOC Observation Form; Revision 0
WC-AA-101; On-Line Work Control Process; Revision 13
TIC 1583; QCGP 2-1 - Normal Unit Shutdown; dated October 12, 2006
OU-AA-101-1005; Exelon Nuclear Outage Scheduling; Revision 2
ER-AA-5300; Raw Water Corrosion Program Guide; Revision 0
ER-AA-5400; Buried Pipe and Raw Water Corrosion Program (BPRWCP) Guide; Revision 0
ER-AA-1002; Buried Piping Examination Guide; Revision 0

ER-AA-340-1001; GL 89-13 Program Implementation Instructional Guide; Revision 6
HU-AA-1212; Technical Task Risk/Rigor Assessment, Pre-Job Brief, Independent Third Party Review, and Post-Job Brief; Revision 0
OP-AA-1080103; Locked Equipment Program; Revision 2
CPS 1019.05; Transient Equipment/Materials; Revision 11
CPS 3310.01C001; Restoring RCIC after maintenance outage-oil system breached; Revision 1
CPS 3800.02; Area Operator Logs; Revision 18e
CPS 8902.01; Oil Sampling; Revision 7
CPS 9000.02D001; Unit Attendant Surveillance Log Data Sheet; Revision 36f
CPS 9054.01C002; RCIC (1E51-C001) High Pressure Operability Checks; Revision 2a

Issue Reports

511926; 1SX54AB-1.5" showing signs of wall loss; July 21, 2006
604841; Reschedule repair of 1SX54AB-1.5" show signs of wall loss; March 16, 2007
80546; RT and UT results identify SX pipe wall reduction and blockage; October 26, 2001
123025; SX pipe degradation (1SX12AA, AB 2.5"); September 16, 2002
189152; 1SX12AA wall loss due to pitting; December 4, 2003
293969; Predefine Radiography results identify SX piping wall loss; January 25, 2005
258113; Enhancement Issue - Terry Turbine User Group Guide Application for RCIC Turbine; September 29, 2004
488902; RCIC Pump flow higher than acceptable range (681 GPM); May 10, 2006
520894; VTIP Check-In FASA - Vendor Document number not entered in Passport; August 17, 2006
520065; VTIP Check-In FASA CC-AA-204 Attachment 1 not updated in Passport; August 15, 2006
516050; NOS I.D.s VETIP is not properly maintaining vendor manuals; August 2, 2006
472231; VTIP Manual in K2864-0001 is not latest revision; March 29, 2006
448411; C1R10 Increase in BRAC point dose rates; February 1, 2006
462302; Three Condenser Boot inleakage locations identified; March 6, 2006
226819; NOS identified Lack of Timely actions to correct VETIP problems; June 8, 2004
455995; Refuel floor non-cavity work greater than estimate; February 20, 2006
449976; Lead shielding installation results in ineffective dose reduction; February 4, 2006
449995; ISI Bioshield ALARA plan deviations and changes; February 4, 2006
451734; ALARA estimates for CR10 Refuel work; February 9, 2006
458297; Increased dose rates and contamination during drain down; February 24, 2006
439211; Plug and Stem separated on 1FC-004A; January 5, 2006
594756; 1CM01SA: Incorrect Carrier Gas Found Installed; February 22, 2007

Root, Apparent and Common Cause Reports

Equipment Apparent Cause Evaluation 488902; Reactor Core Isolation Cooling (RCIC) Flow Higher than Acceptable Range; May 10, 2006
Root Cause Report 448411; C1R10 Increase in BRAC point dose rates; March 16, 2006
Root Cause Report 462302; Three Condenser Boot Inleakage locations; April 20, 2006
Equipment Apparent Cause Evaluation 439211; Plug and stem separated on 1FC004A; March 31, 2006
Equipment Apparent Cause Evaluation 555312; Crack found in housing for level switch during WO 924362; December 7, 2006

Equipment Apparent Cause Evaluation 552156; Condition monitoring failure - LD Inst 1E31N085A - RCIC Isolation; December 1, 2006
Equipment Apparent Cause Evaluation 531065; RCIC Turbine stayed at incorrect speed during 9054.01C004; October 13, 2006
Equipment Apparent Cause Evaluation 426309; Division 3 Diesel Generator tripped during 9080.03; March 30, 2006
Equipment Apparent Cause Evaluation 398451; Division 2 Diesel Generator control power fuse block high resistance connection; December 22, 2005
Equipment Apparent Cause Evaluation 264857; Division 2 Diesel Generator high resistance fuse connection; January 26, 2004
Equipment Apparent Cause Evaluation 196636; Excessive leakage past damper 0VC-10YB; December 10, 2004
Equipment Apparent Cause Evaluation 443964; Failure of Main Control Room ventilation supply fan 0VC-03CA; May 12, 2006
Equipment Apparent Cause Evaluation 169000; 0VC-04CB fan tripped when starting; April 9, 2004
Equipment Apparent Cause Evaluation 219667; VC A ventilation failed surveillance 9070.02 step 9.1.2; September 15, 2004
Equipment Apparent Cause Evaluation 246645; Potential failure of 0VC-04YB, ITS 3.7.3 unplanned entry; November 4, 2004
Root Cause Report 201183-04; C1R09 Source Term; March 24, 2004
Root Cause Report 216449-04; Inaccurate C1R09 Man-hour estimate impacts outage dose estimate; May 15, 2004
Root Cause Report 457969; C1R10 Revised dose estimates exceeded; May 26, 2006
Apparent Cause Evaluation 176490; Debris found in DG air start system check valve; March 3, 2004
Common Cause Analysis 491062; Leaks at Clinton Power Station; July 20, 2006
Common Cause Analysis 523092; Adverse Trend in Operations Human Performance; September 21, 2006

<u>Self-Assessments and NOS Audits</u>

Check-In Self-Assessment 252673; NRC Commitments; September 22, 2004
Check-In Self-Assessment 284436; Operational and Technical Decision Making Process Implementation; June 30, 2005
Check-In Self-Assessment 284483; System Performance Monitoring; May 6, 2005
Check-In Self-Assessment 350214; Review Station Rigor in Scheduling and Removing Operations Compensatory Action(s), Work Arounds and Challenges; September 9, 2005
Check-In Self-Assessment 493763; Organizational Effectiveness; June 30, 2006
Focused Area Self Assessment 284475; Corrosion Monitoring Assessment for Circ Water and Closed Cooling Water Systems; January 15, 2005
Focused Area Self Assessment 476072; Generic Letter 89-13; January 18, 2007
Focused Area Self-Assessment 482437; Technical Human Performance; June 26-30, 2006
Focused Area Self-Assessment 476076; Problem Identification and Resolution; January 15-26, 2007
Focused Area Self-Assessment 295949; Clinton Power Station Air Operated Valve Program; April 13, 2005
Nuclear Oversight Audit NOSA-CPS-05-01; Corrective Action Program; April 25 - May 6, 2005
Nuclear Oversight Audit NOSA-CPS-05-05; Engineering Design Control; October 3-14, 2005

Nuclear Oversight Audit NOSA-CPS-05-07; Operations; August 29 - September 16, 2005
Nuclear Oversight Audit NOSA-CPS-06-01; Maintenance; March 6-17, 2006
Nuclear Oversight Audit NOSA-CPS-04-05; Engineering Programs; June 16, 2004
Nuclear Oversight Audit NOSA-CPS-06-05; Engineering Programs; August 9, 2006

OPEX Documents

OPEX Daily Events Report for February 23, 2007
OPEX Daily Events Report for March 20, 2007
OPEX Daily Events Report for March 6, 2007
IR 598704; IGSCC Identified in Recirc Noz Welds at Duane Arnold; March 2, 2007
IR 606617; UT of Recirc Safe-End Weld Flaws at Duane Arnold; March 20, 2007
IR 293527; NER NC-05-002 Yellow - BWR Bottom Head drain inspection; January 24, 2005
IR 258961; Corporate Review of RX Bottom Head Drain Inspection Issues; October 1, 2004
IR 568249; NRC IN 2006-15 Vibration Induced Valve Degradation; March 30, 2007
IR 598413; Failure of Cutler Hammer DHP-VR Breaker at Susquehanna; March 2, 2007
IR 597743; OPEX - Oconee Unit 1 and 2 tripped due to a grid transient; March 30, 2007
IR 549209; Potentially Defective External Lead Wire Connections in Barton Transmitters; September 29, 2006
IR 550910; NRC IN 2006-17 External Impacts on Service Water Systems; March 30, 2007
IR 549235; NRC IN 2006-20 Foreign material in ECCS; January 26, 2007
IR 372936; NRC IN 2005-23 Identify susceptible valves/CA's per assignment 1 and IR 480638; December 14, 2006
IR 534658; Determine if CPS feedwater turbines utilize the subject strainers referenced in OPEX; November 22, 2006
IR 547835; NRC IN 2006-22 Ultra low sulfur diesel fuel; November 22, 2006
IR 520869; Forsmark loss of power/loss of 2 EDG's; August 17, 2006
IR 473393; Implement WC-AA-101, Revision 12 and brief applicable site personnel (NRC IN 2006-02); August 17, 2006
IR 372896; NRC IN 2005-21 Plant Trip - inadequate switchyard maintenance; November 15, 2005
IR 380153; Internal Flood Design / NRC IN 2005-30; September 30, 2005
IR 253533; Floor Plug Design requirements; November 19, 2004
IR 221751; Site review of NRC IN 2004-09; July 16, 2004
IR 221750; Site review of NRC IN 2004-08; July 16, 2004
IR 205267; Failure of Safety Injection Pump Lube Oil Coolers; April 16, 2004

Issue Reports generated for the inspection included

607505; 2007 NRC PI&R Inspection Question 28, Enhancement IR; March 22, 2007
607103; Post job review IRs closed with out resolution of recommendations; March 21, 2007
607071; Lesson Learned 453921 closed while still unresolved; March 21, 2007
601487; 2007 NRC PI&R Evaluate Revising Locked Equipment Procedure; March 9, 2007
607316; Document Design Basis Review of RP Stanchions in Containment; March 22, 2007

Other

EC 344960; Division I, II and III pipe wall thinning analysis; Revision 0; October 16, 2003
WO 457011; Perform Radiography and UT Examinations of 1SX12AB; September 3, 2002

WO 470393; Perform UT on 1SX12AA to Support GL89-13 Program; September 3, 2002
WO 521322; Perform UT Measurements on line1SX12AB-2.5"; January 9, 2003
WO 492040; Perform UT/RT on 1SX12AA to Support GL89-13 Program; December 2, 2003
WO 492041; Perform Radiography and UT Examinations of 1SX12AB; September 15, 2003
WO 642695; Perform Radiography and UT Examinations of 1SX12AB; September 7, 2004
WO 778326; Perform Radiography and UT Examinations of 1SX12AB; June 22, 2005
WO 486651; Replace 1SX12AA 2.5 Due to Wall Thinning (CR123025); July 24, 2003
WO 486651; Replace 1SX12AB 2.5 Due to Wall Thinning (CR123025); April 7, 2004
Evaluation of 1SX12AA 2.5"; SX supply piping to the spent fuel pool; Revision 0;
January 16, 2003
Micro ALARA plan for WO 895931; Weld Repair the leak on the pipe 1ES06BB; March 2, 2007

LIST OF ACRONYMS

ACE	Apparent Cause Evaluation
CCA	Common Cause Evaluation
DP	Differential Pressure
EPRI	Electric Power Research Institute
FME	Foreign Material Exclusion
HVAC	Heating, Ventilation, and Air Conditioning
NCV	Non-Cited Violation
OE	Operating Experience
RCR	Root Cause Report
SBGT	Standby Gas Treatment
SRV	Safety Relief Valve
SSD	Safe Shutdown
TRM	Technical Requirements Manual
UFSAR	Updated Final Safety Analysis Report