January 23, 2003

Mr. John T. Conway
Vice President Nine Mile Point
Nine Mile Point Nuclear Station, LLC
P.O. Box 63
Lycoming, NY 13093

SUBJECT: NINE MILE POINT NUCLEAR STATION - NRC INTEGRATED INSPECTION REPORT 50-220/02-06, 50-410/02-06

Dear Mr. Conway:

On December 28, 2002, the NRC completed an inspection of your Nine Mile Point Nuclear Station, Units 1 and 2. The enclosed report documents the inspection findings which were discussed on January 10, 2003, with you and other members of your staff.

This 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, the inspectors identified two findings of very low safety significance (Green). Neither of these issues was determined to be a violation of NRC requirements.

Since the terrorist attacks on September 11, 2001, the NRC has issued two Orders (dated February 25, 2002, and January 7, 2003) and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve security force readiness, and enhance access authorization. The NRC also issued Temporary Instruction 2515/148 on August 28, 2002, that provided guidance to inspectors to audit and inspect licensee implementation of the interim compensatory measures (ICMs) required by the February 25th Order. Phase 1 of TI 2515/148 was completed at all commercial nuclear power plants during calendar year (CY) '02, and the remaining inspections are scheduled for completion in CY '03. Additionally, table-top security drills were conducted at several licensees to evaluate the impact of expanded adversary characteristics and the ICMs on licensee protection and mitigative strategies. Information gained and discrepancies identified during the audits and drills were reviewed and dispositioned by the Office of Nuclear Security and Incident Response. For CY '03, the NRC will continue to monitor overall safeguards and security controls, conduct inspections, and resume force-on-force exercises at selected power plants. Should threat conditions change, the NRC may issue additional Orders, advisories, and temporary instructions to ensure adequate safety is being maintained at all commercial power reactors.

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

Sincerely,

/RA/

James M. Trapp, Chief
Projects Branch 1
Division of Reactor Projects

Docket Nos. 50-220, 50-410
License Nos. DPR-63, NPF-69

Enclosure: Inspection Report 50-220/02-06, 50-410/02-06
w/Attachment: Supplemental Information

cc w/encl:
M. J. Wallace, President, Nine Mile Point Nuclear Station, LLC
M. Wetterhahn, Esquire, Winston and Strawn
J. M. Petro, Jr., Esquire, Counsel, Constellation Power Source, Inc.
P. D. Eddy, Electric Division, NYS Department of Public Service
C. Donaldson, Esquire, Assistant Attorney General, New York Department of Law
J. V. Vinquist, MATS, Inc.
W. M. Flynn, President, New York State Energy Research and Development Authority
Supervisor, Town of Scriba
C. Adrienne Rhodes, Chairman and Executive Director, State Consumer Protection Board
T. Judson, Central NY Citizens Awareness Network

Distribution w/encl: H. Miller, RA/J. Wiggins, DRA (1)
J. Trapp, DRP
H. Nieh, RI EDO Coordinator
R. Laufer, NRR
P. Tam, PM, NRR
D. Skay/T. Colburn, PM, NRR (Backup)
G. Hunegs, SRI - Nine Mile Point
B. Fuller, RI - Nine Mile Point
N. Perry, DRP
P. Torres, DRP
Region I Docket Room (with concurrences)

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U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket Nos: 50-220, 50-410

License Nos: DPR-63, NPF-69

Report No: 50-220/02-06 and 50-410/02-06

Licensee: Nine Mile Point Nuclear Station, LLC (NMPNS)

Facility: Nine Mile Point, Units 1 and 2

Location: P. O. Box 63
Lycoming, NY 13093

Dates: September 29, 2002 - December 28, 2002

Inspectors: G. Hunegs, Senior Resident Inspector
B. Fuller, Resident Inspector
S. Barr, Operations Engineer
J. Caruso, Senior Operations Engineer
J. D'Antonio, Operations Engineer
N. Della Greca, Senior Reactor Inspector
D. Dempsey, Resident Inspector
P. Frechette, Safeguards Inspector
R. Fuhrmeister, Senior Reactor Inspector
T. Hipschman, Reactor Inspector
J. Jang, Senior Health Physicist
E. Knutson, Resident Inspector
J. Noggle, Senior Health Physicist
N. Perry, Senior Project Engineer
D. Silk, Senior Emergency Preparedness Specialist
J. Talieri, Reactor Inspector
K. Young, Reactor Inspector

Approved by: James M. Trapp, Chief
Projects Branch 1
Division of Reactor Projects

Summary of Findings

IR 05000220/2002-006, 05000410/2002-006; Nine Mile Point Nuclear Station, LLC; 9/29/2002 - 12/28/2002; Nine Mile Point, Units 1 and 2. ALARA Planning and Controls

This report covered a 13 week period of inspection by resident inspectors and announced inspections by 13 region-based inspectors. In addition, on January 7, 2002, an in-office assessment of the 2002 annual operating exam results was performed using the guidance of NRC Manual Chapter 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process (SDP)."

Two Green findings and two unresolved items were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using IMC 0609, “Significance Determination Process,” (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC’s program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 3, dated July 2000.

A. Inspector Identified and Self-Revealing Findings

Cornerstone: Occupational Radiation Safety

- Green. During the Spring 2002 Unit 2 refueling outage, under-vessel work activities resulted in collective exposures of 47.2 person-rem based on 18 person-rem estimated for the work activities. After giving credit for higher dose rates than expected (9.5 person-rem), this work activity was 72 percent above a 27.5 person-rem adjusted estimate.

  The occupational radiation safety significance determination process screening criteria for work activity exposure greater than 5 person-rem and greater than 50 percent above estimated were exceeded. The performance deficiency that resulted in the exposure overrun was due to inexperienced and poorly trained personnel, and vendor equipment problems. Constellation Nuclear’s three-year rolling average (99-01) is 179 person-rem, which is below the SDP criteria of 240 person-rem for Boiling Water Reactors (BWRs), therefore, overall ALARA performance has been effective and this finding is of very low safety significance. (Section 2OS2)

- Green. During the Spring 2002 Unit 2 refueling outage, hydraulic control unit (HCU) valve maintenance resulted in 6.91 person-rem of collective exposure based on an exposure estimate of 1.8 person-rem. This work activity was 283 percent above the estimate.

  The occupational radiation safety significance determination process screening criteria for work activity exposure greater than 5 person-rem and greater than 50 percent above estimated were exceeded. There were two performance deficiencies that were attributed to this exposure overrun. There was an 83 percent increase in work-hours and exposure due to the improper installation of 139 solenoid operated valve spring clips and air supply hoses that required rework. In addition, after the scram at the start of the outage, rather than isolating and draining the scram discharge volume (SDV) piping immediately after the scram, as is typically done, the licensee left the SDV connected and pressurized to the reactor coolant system in preparation for an outage in-service test. Although leaving the SDV connected to the reactor coolant system was a planned evolution, radiation protection personnel were not involved in the planning activities. This resulted in 73 percent higher dose rates during HCU maintenance due to an outage crud burst spreading into the SDV piping. Constellation Nuclear's three-year rolling average (99-01) is 179 person-rem, which is below the SDP criteria of 240 person-rem for Boiling Water Reactors (BWRs), therefore, overall ALARA performance has been effective and this finding is of very low safety significance. (Section 2OS2)

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REPORT DETAILS

Summary of Plant Status

Nine Mile Point Unit 1 (Unit 1) began the inspection period at 100 percent power using four recirculation loops due to maintenance in progress on the 14 recirculation motor generator set. On November 3, 2002, power was reduced to 85 percent to return the 14 recirculation loop to service, and reactor power was returned to 100 percent. On December 5, Unit 1 was shut down due to elevated unidentified drywell leakage. Leakage was identified from the reactor building closed loop cooling (RBCLC) system. After repairs, the unit was restarted on December 11. Later that day, the licensee identified elevated tailpiece temperatures on the 111 electromatic relief valve pilot valve. The plant was returned to cold shutdown, and debris was found in the pilot valve which prevented it from fully seating. The unit was restarted on December 12, and during a drywell walkdown, leakage was identified at a threaded connection for a drywell area cooler RBCLC discharge line. The unit was shut down on December 13 to repair the leak and further evaluate extent of condition. Additional portions of RBCLC piping were replaced and Unit 1 was restarted on December 24. Unit 1 reached 100 percent power on December 26 and remained there through the end of the inspection period.

Nine Mile Point Unit 2 (Unit 2) began the inspection period at 100 percent power. On October 12, reactor power was lowered to 90 percent to investigate an indication of a fuel bundle leak. On October 21, reactor power was lowered to 60 percent to perform a power suppression test for positive leak identification. The leak was identified in fuel bundle 18-55 and suppressed. On October 25, power was returned to 100 percent. On November 11, Unit 2 automatically scrammed due to high reactor vessel pressure, caused by the closure of a main steam isolation valve as a result of the disc separating from the valve stem. Unit 2 was returned to full power on November 26. On December 16, Unit 2 automatically scrammed due to the failure of a stator cooling temperature control valve position feedback connection. Unit 2 was restarted on December 18, but was shut down to repair a leak on the ‘A’ moisture separator reheater manway gasket and to address the failure of main steam isolation valve 7A to operate properly. Following repairs, Unit 2 was restarted on December 25, and returned to full power on December 27, and remained at full power through the end of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection

a. Inspection Scope

The inspectors reviewed the Unit 2 procedure for cold weather preparations, N2-OP-102, “Meteorological Monitoring, Attachment 2: Cold Weather Preparation Checklist,” and the Unit 1 procedure, N1-PM-A5, Revision 2, “Cold Weather Preparation and Operation.” The inspectors verified that risk-significant systems, including fire protection and reactor and turbine building ventilation, will remain functional when challenged by cold weather, through review of the Updated Safety Analysis Report (USAR) and Technical Specifications. The inspectors verified that initialed items on the Cold Weather Preparation Checklist were either completed or scheduled for completion in the near future. Specifically, the inspectors reviewed the Night Note to operators, discussed its contents with operations personnel, and verified by walkdown that outside lighting, including main stack lighting, was operational, and outside doors in the power block were secure and weather tight.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

a. Inspection Scope

Partial System Walkdowns:

The inspectors performed two partial system walkdowns during this inspection period.

The inspector selected the Unit 2, Division I residual heat removal system (RHS) to conduct a partial system walkdown while the Division II RHS was out of service. The walkdown included the control room switch verification and physical inspection and verification of the RHS configuration. N2-OP-31, "Residual Heat Removal System," Revision 15, was used for this review.

The inspector selected the Unit 1 reactor building closed loop cooling system (RBCLC) inside the drywell to conduct a partial system walkdown. The walkdown included portions of piping associated with the drywell equipment drain coolers, recirculation pump motor and seal coolers, and area coolers. N1-OP-11, "Reactor Building Closed Loop Cooling," Revision 19, was used for this review.

Complete System Walkdown:

The inspector performed a complete walkdown of the Unit 1 liquid poison system. The inspector reviewed the Final Safety Analysis Report description for the system, system health reports and surveillance procedures. The inspector verified proper valve position, component alignment and system material condition using system drawings and operating procedure, N1-OP-12, "Liquid Poison System." A review of outstanding maintenance work orders was performed to verify that the deficiencies did not adversely affect the liquid poison system function.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

.1 Routine Area Inspection

a. Inspection Scope

The inspectors walked down accessible portions of four fire areas described below to determine if there was adequate control of transient combustibles and ignition sources. The condition of fire detection devices, the readiness of the sprinkler fire suppression systems and the fire doors were also inspected against industry standards. In addition, the fire protection features were inspected, including the ventilation system fire dampers, structural steel fire proofing, and electrical penetration seals. Reference material reviewed for installed features included the Updated Safety Analysis Report. The following plant areas were inspected:

- Steam tunnel (Unit 2)
- Reactor Building 340' elevation (Unit 1)
- Screenwell Building (Unit 2)
- Diesel and Electric Fire Pump Room (Unit 2)

b. Findings

No findings of significance were identified.

.2 Annual Observation of a Fire Brigade Drill

a. Inspection Scope

The inspectors observed a fire brigade drill conducted on October 25, 2002, involving a simulated fire in the Unit 2, Division II Emergency Diesel Generator Room, a plant area important to safety. The inspector reviewed the Fire Drill Scenario, 2-01.03, and the Fire Brigade Drill Assessment (Attachment 1 to NTP-TQS-402). The inspector evaluated the readiness of the brigade to prevent and fight fires by observing the following: protective clothing properly donned; self-contained breather apparatus equipment properly worn; fire hose lines properly laid out and capable of reaching all necessary fire hazard locations; fire area of concern entered in a controlled manner; sufficient fire-fighting equipment brought to the scene; fire brigade leader's directions thorough, clear, and effective; brigade checked for victims and propagation of fire into other areas; effective smoke removal operations simulated; and the drill was pre-planned, followed, and objectives and critical items were met. Additionally, the inspector attended the post-drill critique.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

a. Inspection Scope

The inspectors walked down eight susceptible risk significant systems to verify that internal flooding mitigation plans and equipment were consistent with design requirements and the risk analysis assumptions contained in the Updated Safety Analysis Report. The condition of flood protection doors and sumps was also inspected against industry standards. The following plant areas were inspected:

- Reactor Building Emergency Core Cooling System (ECCS) corner rooms 198' elevation (NW, NE, SW, SE) (Unit 1)
- Screenwell Building (Unit 2)
- Emergency Diesel Building (Unit 2)
- Reactor Building 175' elevation (Unit 2)

Additionally, the inspectors reviewed exterior design features, associated with both units, for external flooding protection. Specifically, the berms around the plants, and the Unit 1 dike and Unit 2 revetment ditch system were walked down to verify that condition of these features was consistent with the Updated Safety Analysis Report and procedure N2-MSP-GEN-V001, “Revetment Ditch Structure Inspection.” The most recent completed N2-MSP-GEN-V001 procedure was also reviewed.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance

a. Inspection Scope

The inspectors performed reviews of performance test data for three heat exchangers and the Unit 1 intake structure.

The licensee’s methods (inspection, cleaning, maintenance, and performance monitoring) used to ensure heat removal capabilities for the Unit 1 reactor building closed loop cooling (RBCLC) heat exchangers, the Unit 2 emergency diesel generator Division II room cooler, and the Unit 2 emergency switchgear Division II room cooler were reviewed and compared to the commitments made in response to Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment." The inspectors compared the surveillance test data to the acceptance test criteria which had been developed in engineering calculations. The inspectors also reviewed these criteria to ensure that the minimum design bases assumptions were technically justified. The inspectors reviewed the test methodology and results to verify that the number of plugged RBCLC heat exchanger tubes was bounded by assumptions in the engineering analyses.

The inspectors reviewed the design fouling factor assumptions for the RBCLC heat exchangers and the engineering analyses of maximum calculated RBCLC outlet temperature for the RBCLC safety-related components. This review was performed to verify that the maximum calculated RBCLC outlet temperature supported the minimum heat transfer rates assumed for the RBCLC essential loads during accident and transient conditions. Preventive maintenance procedures were reviewed to verify activities existed for cleaning of the RBCLC heat exchangers to ensure the fouling factors assumed in engineering analyses were reasonable.

The inspectors observed the Unit 2 emergency diesel generator Division II room cooler and the Unit 2 emergency switchgear Division II room cooler performance testing and compared it against the heat exchanger specification sheets. This included calculations related to maximum allowable service water flowrate to the coolers. Additionally, the calculations were reviewed to ensure that operability assumptions in the calculations were consistent with the actual condition of the heat exchangers.

The inspectors reviewed the Unit 2 methods for controlling biotic fouling, particularly the zebra mussel control strategy, treatment methods, and monitoring.

The inspector walked down the Unit 1 intake structure and reviewed deficiency reports to verify that any potential common cause performance problems that could affect the Unit 1 ultimate heat sink were identified. Additionally, the inspector verified that any intake structure performance problems, such as icing or silt build-up, that could result in initiating events or affect multiple heat exchangers, were identified and corrected.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

.1 Routine Observations

a. Inspection Scope

The inspectors reviewed two licensed operator requalification training activities during this inspection period to assess the licensee’s training program effectiveness. The inspectors observed Unit 1 simulator training conducted on October 3, 2002 as part of a site emergency drill, and Unit 2 licensed operator simulator training on October 30, 2002. The inspectors reviewed performance in the areas of procedure use, self and peer-checking, completion of critical tasks, and training performance objectives. Following the simulator training, the inspectors observed the crew debrief and critique, and reviewed simulator fidelity through a sampling process. At Unit 1, the inspector evaluated emergency response organization performance regarding initial and subsequent actions by licensed operators.

b. Findings

No findings of significance were identified.

.2 Licensed Operator Requalification Program

a. Inspection Scope

The following inspection activities were performed using NUREG-1021, Rev. 8, "Operator Licensing Examination Standards for Power Reactors," Inspection Procedure Attachment 71111.11, "Licensed Operator Requalification Program," and NRC Manual Chapter 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process (SDP)," as acceptance criteria. These inspection activities were performed for both units.

The inspectors reviewed documentation of operating history since the last requalification program inspection. Documents reviewed included NRC inspection reports and licensee deficiency reports. The inspectors also discussed facility operating events with the resident staff. The inspectors did not detect operational events that were indicative of possible training deficiencies.

Inspectors reviewed examples of the comprehensive written exams and observed the administration of annual operating tests. The quality of the written exams and the annual operating tests met or exceeded the criteria of the Examination Standards and 10 CFR 55.59.

For both Unit 1 and 2 simulators, the inspectors observed simulator performance during the conduct of the examinations, reviewed simulator performance tests (e.g., steady state performance tests, selected transient tests, and LOR program scenario-based tests), and discrepancy reports to verify compliance with the requirements of 10CFR55.46.

The inspectors reviewed a sample of operators' records related to requalification training attendance, license reactivations, and medical examinations and confirmed the operators were in compliance with license conditions and NRC regulations.

Instructors, training/operations management personnel, and a sample of individual licensed operators were interviewed for feedback regarding the implementation of the licensed operator requalification program.

On January 7, 2003, the inspectors conducted an in-office review of licensee requalification exam results. These results included the annual operating test and comprehensive written exam. The inspection assessed whether pass rates were consistent with the guidance of NRC Manual Chapter 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process (SDP)." The inspectors verified that:

- Crew pass rate was greater than 80%. (Unit 1 pass rate was 100%; Unit 2 was 100%.)

- Individual pass rate on the dynamic simulator test was greater than or equal to 80%. (Unit 1 pass rate was 100%; Unit 2 was 98%.)

- Individual pass rate on the walk-through test was greater than or equal to 80%. (Unit 1 pass rate was 100%; Unit 2 was 100%.)

- Individual pass rate on the comprehensive biennial written exam was greater than or equal to 80%. (Unit 1 pass rate was 100%; Unit 2 exam was not administered this year.)

- Overall pass rate among individuals for all portions of the exam was greater than or equal to 75%. (Unit 1 pass rate was 100%; Unit 2 was 98%.)

b. Findings

Introduction

During the week of September 30, 2002, while administering the Unit 1 RO/SRO initial operator license NRC exam, the examiners identified that the guidance provided to the operators in the Emergency Operating Procedures (EOP-2, "RPV Control") may be inadequate under certain conditions. While administering (Scenario 1, Rev. 3, "APRM Failure/Recirc Pump Seal Leakage/EPR MPR Failure/LOCA with Degraded Core Spray Systems") the NRC examiners determined that in a medium to large break Loss of Coolant Accident (LOCA) event with no feedwater (FW) pumps available and a high pressure coolant injection (HPCI) signal present, there was no approved method designated in EOP-2, "RPV Control," to allow injection from the condensate and FW booster pumps into the vessel.

Description

In the exam scenario, high pressure feed pumps were not available but the condensate and feed booster pumps were running and could not inject into the vessel because of an existing HPCI interlock. EOP-2, "RPV Control" directs in steps L-3 and L-7 to restore and maximize injection using all preferred sources which include condensate/FW pumps. These steps could not be implemented because the HPCI logic (interlock) prevented operation of the FW flow control valves (29-137, 29-141, 29-49 and 29-50) with less than 990 psig at the FW pump discharge. This logic interlock was intended to prevent HPCI from starting a FW pump in a run-out flow condition. This is a unique design feature to Nine Mile Unit 1 and does not exist at other BWR plants. The administered exam scenario involved a medium break LOCA, with a loss of all high pressure injection (with the exception of control rod drive and the standby liquid control systems), the core spray system was also degraded with a loss of one pump. Without the ability to inject using the condensate and FW booster pumps level degraded to approximately 2/3 core height (-163") and level could not be restored without the use of firewater injection (i.e., an alternate/non-preferred injection system) to the vessel.

Currently, EOP-3, "Failure To Scram," step L-6 permits bypassing of the HPCI interlock by removing HPCI control power fuses (in accordance with procedure N1-EOP-1, Attachment 24, "Terminating/Throttling HPCI"). This allows the operators the capability to inject using condensate/FW in order to maintain RPV level above minimum steam cooling level (-109"), a level below which core damage is more likely to occur. It appears that the use of this contingency was overlooked in EOP-2, "RPV Control," since step L-7 (Level Control), does not currently permit the bypassing of the HPCI interlock. This does appear to be somewhat inconsistent (and an possibly an oversight) since injecting during an anticipated transient without a SCRAM (ATWS) situation would normally be a more restrictive situation. Adding a step to remove control fuses in EOP-2, L-7 would provide an additional means of coolant injection when condensate and/or FW booster pumps were available, a HPCI initiation signal was present, and no feedwater pumps were available. Without this additional procedural guidance provided in EOP-2, "RPV Control" the operators lose the safety function provided by the condensate/FW booster pumps which may require the use of less than desirable alternate injection systems and could result in unnecessarily allowing RPV level to degrade below minimum steam cooling level (-109") and consequently increase the potential for core damage to occur.

Analysis

This issue is more than minor because the EOPs are a key element for directing operator response to mitigate accident and transient conditions. The identified procedure inadequacy could have permitted RPV level to unnecessarily degrade increasing the potential for core damage to occur under certain plant conditions.

Enforcement

This apparent EOP procedure inadequacy would not allow completion of EOP-2, "RPV Control," steps L-3 and L-7 to restore and then maximize injection using the preferred injection source (condensate/feedwater system). The licensee initiated DER 2002-4256 to document this problem within their corrective action program. This item will remain unresolved pending the completion of the licensee actions to resolve this issue. **(URI 50-220/2002-06-01)**

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed two performance-based problems during this inspection period involving selected in-scope structures, systems, and components (SSCs) to assess the effectiveness of the maintenance program. Reviews focused on: (1) proper maintenance rule scoping, in accordance with 10 CFR 50.65; (2) characterization of failed SSCs; (3) safety significance classifications; (4) 10 CFR 50.65 (a)(1) and (a)(2) classifications; and, (5) the appropriateness of performance criteria for SSCs classified as (a)(2), and goals and corrective actions for SSCs classified as (a)(1). The inspectors reviewed the licensee's system scoping documents, system health reports and corrective action program documents. Additionally, the inspectors performed a walkdown of the systems, and discussed the system status and recent performance with engineering and operations personnel.

The Unit 2 high pressure core spray system was selected for review because it was a high-safety-significant system. The Unit 1 reactor building closed loop cooling (RBCLC) system was selected for review due to system degradation and risk significance.

b. Findings

Introduction. The RBCLC system was in a degraded condition for an extended period of time. The corrective action program was not effectively used to develop a rigorous cause evaluation and corrective actions were not initially sufficient to assure that the RBCLC system was adequately repaired.

Description. Unit 1 was shut down on December 5, 2002 after drywell unidentified leak rate increased to 2 gallons per minute. Maintenance crews identified a leaking threaded connection on a reactor building closed loop cooling (RBCLC) check valve in a 1-1/2 inch return line from the drywell number 11 equipment drain tank cooler. Based on evaluation of the extent of condition, the licensee elected to replace a portion of the RBCLC piping, flow switches and unions. The leak on December 5, 2002, was located where the carbon steel pipe threaded into a bronze check valve. The leakage was attributed to galvanic corrosion at threaded connections that contained dissimilar metals. Based on this, an extent of condition review and engineering evaluation was completed which was centered around threaded connections with dissimilar metals. Repairs were made to all threaded connections with dissimilar metals in the drywell. Upon completion of the RBCLC work, the unit was restarted on December 11. During startup, an unrelated problem with a electromatic relief valve (ERV) emerged, requiring the plant to be shut down to affect repairs.

The plant was returned to cold shutdown to determine the cause of the ERV pilot valve tailpiece temperature increase. Upon investigation, debris was found in the pilot valve which prevented it from fully seating. Upon completion of extent of condition review of the ERVs, Unit 1 was restarted on December 12, 2002. During the drywell walkdown conducted at 900 pounds primary pressure, leakage was identified at a threaded connection for a drywell area cooler RBCLC discharge line. The unit was shut down on December 13, to repair the leak and further evaluate the extent of condition. During the extent of condition evaluation, wall thinning due to general corrosion was identified. The effect of threads on pipe wall thickness in conjunction with the pipe wall thinning had not been considered during the previous evaluation. In the drywell, the licensee subsequently replaced all RBCLC fittings and pipe or positively determined piping sections to be acceptable through calculations in combination with ultrasonic and visual inspections.

The RBCLC system provides demineralized water to cool auxiliary equipment located in the reactor, turbine and waste disposal building. The closed loop design permits isolation of systems containing radioactive liquids from the service water, which is used to cool the RBCLC system and is returned to the lake. The RBCLC system provides cooling water to major components including equipment drain tank coolers, drywell air coolers and recirculation pump coolers located in the drywell in addition to fuel pool heat exchangers, instrument air compressors, feedwater pumps, condensate pumps and feedwater booster pumps [the high pressure injection system]. The system consists of three centrifugal pumps, three heat exchangers and associated controls.

Over the years, numerous leaks at threaded unions in the RBCLC system resulted in repeat maintenance repairs. In 1980, a modification was initiated to eliminate certain RBCLC threaded connections in the drywell. However, the modification was not installed, and was canceled in 1994. In May 2002, Unit 1 was shut down to repair leaks at threaded connections in the RBCLC system. The licensee attributed this to inherent leakage associated with threaded connections and noted that leaks at the unions for the seal cooling piping to and from the recirculation pumps has been a chronic problem for many years. Subsequent analysis determined that there had been through wall leakage due to galvanic corrosion, but corrective actions were not implemented to address this. Upon startup from the May 2002 outage, minor additional drywell leakage was observed and confirmed to be from RBCLC. Drywell leakage was monitored until the increase in leakage warranted an additional planned shutdown on December 5, 2002. For the RBCLC system leakage identified in May and December, the apparent causes did not consider mechanisms other than leakage across the threads. In fact, Deviation Event Report (DER) 2002-2383 stated that it is expected that threaded piping connections that are not seal welded will leak over an extended period of time. The cause analysis was not sufficiently rigorous to identify that the schedule 40 pipe threaded area wall thickness was significantly less than the rest of the system, and therefore the cause analysis, extent of condition assessment and scope of repairs were not sufficient to preclude additional RBCLC leakage.

Analysis. The RBCLC system is a safety-related, risk significant system. The piping degradation potentially adversely impacted the structural integrity of the system. This affects the reactor safety mitigating system and initiating events cornerstone objectives and is therefore greater than minor. The significance of this condition will be determined by the planned Special Inspection Team.

Enforcement. The enforcement actions associated with this issue will be determined by the planned Special Inspection Team. This item will be treated as unresolved pending further evaluation by the Special Inspection Team. **(URI 50-220/2002-06-02)**.

1R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors reviewed eight risk assessments and emergent work activities during this inspection period. For selected maintenance work orders (WOs), the inspectors evaluated: (1) the effectiveness of the risk assessments performed before the maintenance activities were conducted; (2) risk management control activities; (3) the necessary steps taken to plan and control resultant emergent work tasks; and (4) the overall adequacy of identification and resolution of emergent work and the associated maintenance risk assessments. The following documents were used for this review:

- GAP-MAI-01, Conduct of Maintenance, Revision 3
- GAP-PSH-01, Work Control, Revision 27
- NEG-CA-010, Online Configuration Risk Management Guidance

The following work items/WOs were reviewed:

- WO 02-10460, Repair instrument air system leak (Unit 2)
- WO 02-11159, Repair drive sleeve on 2 SWP*MOV33B, residual heat removal system heat exchanger service water inlet valve (Unit 2)
- Reactor Recirculation Motor Generator (RRMG) 14 troubleshooting after failed 63X relay and short circuit in control circuit caused reactivity event (Unit 1)
- Observed common cause testing of Division I EDG after failure of cooldown circuit solenoid on Division II EDG. Reviewed root cause of failure to cooldown for Division II EDG (Unit 2)
- Observed troubleshooting efforts after failure of 12 Control Rod Drive (CRD) pump to start. Reviewed DER 1-2002-4518 (Unit 1)
- Observed repair work on 12 CRD pump, including rework after leakage identified upon clearance restoration (Unit 1)
- Observed SORC meeting on contingencies for work on MSIVs in parallel (Unit 2)
- DER 2002-4708, Low contingency voltage for 115 kV grid (Unit 1)

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Non-Routine Plant Evolutions and Events

a. Inspection Scope

For the non-routine events described below, the inspectors reviewed operator logs, plant computer data, and strip charts to verify that the expected plant response was achieved, and operators appropriately conducted the activities in accordance with plant procedures.

- From October 21 to 25, 2002, Unit 2 implemented a power suppression test to identify a leaking fuel assembly. The inspector reviewed and observed portions of the evolution including power changes, the rod sequence, failed fuel management guidelines and N2-REP-31, “Power Suppression Test.” The leaking fuel was identified in fuel bundle location 18-55 and flux was suppressed in the area. This issue was documented in DER NM 2002-4401.

- On November 3, 2002, Unit 1 made a planned reduction in reactor power to restore the Number 14 recirculation pump to service. The inspector observed the pre-evolution briefing and reactor manipulations from the control room.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed eight operability evaluations during this inspection period, which affected risk significant mitigating systems, to assess: (1) the technical adequacy of the evaluation; (2) whether other existing degraded systems adversely impacted the affected system or compensatory measures; (3) where compensatory measures were used, whether the measures were appropriate and properly controlled; and, (4) that the degraded systems remained operable. The following documents were used for this review:

- NIP-ECA-01, Deviation/Event Reports
- GAP-OPS-02, Administration of Operations, Revision 19
- S-ODP-OPS-0116, Operability Determinations
- 10 CFR 21, Report number 0083 dated August 31, 2002

The following licensee documents were reviewed:

- DER 2-2002-4650, Division III emergency diesel generator (EDG) cylinder drain valves left open following procedure to bar over the EDG (Unit 2)
- DER 2-2002-4992, Inability of oscillating power range monitor (OPRM) to detect a potential oscillation (Unit 2)
- DER 2-2002-4755, Spline adapter on 2SWP*MOV33B drive sleeve was found outside tolerances (Unit 2)
- DER 2-2002-4372, Division II EDG failure of cooldown circuit solenoid (Unit 2)
- DER 1-2002-4570, 12 CRD pump failure to maintain discharge flow (Unit 1)
- DER 1-2002-4662, 13 Condensate pump expansion joint degraded (Unit 1)
- DER 1-2002-4843, Failure of 11 High Pressure Coolant Injection (HPCI) controller during monthly surveillance (Unit 1)
- DER 2-2002-4850, Foreign material found in ‘B” recirc pump (Unit 2)

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds

a. Inspection Scope

The inspector reviewed operator workarounds at Units 1 and 2 to determine if any had a potential adverse effect on the functionality of mitigating systems. Included in this review were the effect on (1) the reliability, availability, and potential for mis-operation of a system; (2) the potential increase in initiating event frequency that could affect multiple mitigating systems; and (3) the ability of operators to respond in a correct and timely manner to plant transients and accidents. Additionally, the inspector looked for any combined effects of the operator workarounds.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

a. Inspection Scope

Design document change (DDC) 2M11093A, Main Steam Isolation Valve (MSIV) Stem/Disc Assembly, incorporates an improved method of attachment between the disc and stem for Unit 2 MSIVs. The inspector reviewed selected portions of the modification package including the safety evaluation screening forms, 10 CFR 50.59 safety evaluation, design calculations, and results of post-modification testing. The inspector discussed the scope and extent of the modification, technical aspects of the change and implementation of the change with the responsible engineering personnel.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing

a. Inspection Scope

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

- WO - 02-04820, Cutout and replace core spray topping pump mechanical seal check valve, CKV-81-187 (Unit 1)
- Observed attempted start of 12 CRD pump from control room after breaker maintenance. Pump failed to start, overcurrent trip device was determined to be failed (Unit 1)
- Observed removal of clearance tags at 12 CRD pump after rotating element replacement. There was leakage from both inboard and outboard stuffing boxes when cooling water pressure was applied to pump (Unit 1)
- Reviewed N1-PM-V2, Pump Curve Validation, which was performed on for the 12 CRD pump on October 26, 2002. Test points were not in accordance with the methodology of MDC [Mechanical Design Criteria]-11. Due to system limitations, points were selected that would work for CRD as allowed by MDC-11. (Unit 1)
- Observed restart of 14 RRMG after maintenance outage (Unit 1)
- N2-ISP-MSS-R001, Main Steam Isolation Valve Leak Rate Test (Unit 2)

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors witnessed performance of four surveillance test procedures and reviewed test data of selected risk significant SSC's to assess whether the SSC's satisfied Technical Specifications, Updated Final Safety Analysis Report (UFSAR), and licensee procedure requirements; and to determine if the testing appropriately demonstrated that the SSC's were operationally ready and capable of performing their intended safety functions. The following tests were witnessed:

- N2-ISP-RDS-Q102, Quarterly Functional/calibration of Scram Discharge Volume High Water Level Scram Float Switch Instrument Channels (Unit 2)
- N2-OSP-EGS-R002 Operating Cycle Diesel Generator 24 Hour Run and Load Rejection Division I and II (Unit 2)
- N1-ST-M3, Suppression Chamber - Drywell Relief Valve Exercising (Unit 1)
- NDEP-VT-2.01, ASME Section XI Visual Examination, Control Rod Drive Stub Tubes (Unit 1)

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed three temporary plant modifications during this inspection period.

In October, 2002, an instrument air system line developed a crack. The inspector reviewed temporary change package (TCP) No. N2-02-211 for the temporary repair of an instrument air system line at Unit 2. The TCP was initiated to install a piping enclosure to terminate the leak until permanent repairs could be made. The inspector verified that the 10 CFR 50.59 screening form evaluation was adequate, that the installation was consistent with the temporary modification documentation, that the post-modification functional testing was acceptable, and that the piping enclosure provided adequate sealing of the leak while ensuring pressure and structural integrity. Implementation of work order 02-10460 to install the piping enclosure was observed.

The inspector reviewed TCP No. N2-02-064 for shroud head bolt reduction at Unit 2. The original design of the shroud head flanged joint used 36 shroud head bolts to maintain the joint clamping force. This temporary change declared up to four shroud head bolts “non-functional” and provided calculations and justification that at least 32 shroud head bolts rather than the full complement of 36 would be sufficient. The inspector verified that the 10 CFR 50.59 screening evaluation was adequate, reviewed the design input package, calculations, and supporting documentation and discussed the TCP with design engineering. Licensee procedure NIP-CON-01, “Configuration Control,” was used for this review.

The inspector reviewed TCP No. N2-02-100 for the installation of a strongback onto 2SWP*MOV74C, service water pump P1C discharge valve. Unit 2 personnel identified possible dowel pin degradation which could result in valve stem movement to the extent that the valve becomes inoperable. The design function of the dowel pin is to prevent lateral movement of the shaft. The strongback serves as a valve stem retention device to back up the dowel pin and ensures the adapter spline and drive shaft remain inserted within the valve and actuator housing. The inspector verified that the 10 CFR 50.59 screening evaluation was adequate, reviewed the design input package, calculations and supporting documentation and verified that no function of the valve was compromised by the installation of the strongback. Post modification testing was conducted in accordance with N2-OSP-SWP-Q@001, “Service Water Operability Test.”

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP04 Emergency Action Level and Emergency Plan Changes

a. Inspection Scope

The inspector conducted an in-office review of licensee-submitted changes for the Site Emergency Plan, Rev. 47, to determine if the changes decreased the effectiveness of the plan. A thorough review was conducted of aspects of the plan related to the risk significant planning standards (RSPS), such as classifications, notifications and protective action recommendations. A cursory review was conducted for non-RSPS portions. These changes were reviewed against 10 CFR 50.54(q) to ensure that the changes do not decrease the effectiveness of the plan, and that the changes as made continue to meet the standards of 10 CFR 50.47(b) and the requirements of Appendix E. These changes are subject to future inspections to ensure that the impact of the changes continues to meet NRC regulations.

b. Findings

No findings of significance were identified.

1EP06 Emergency Preparedness (EP) Drill Evaluation

a. Inspection Scope

On October 3, 2002, the licensee conducted an EP drill. The inspectors reviewed the drill scenario, applicable emergency plan implementing procedures (EPIPs), and emergency action levels (EALs). The inspectors observed licensee performance during the drill including event classification, offsite authority notification, and dose assessment activities. Mitigation strategies and communications were observed. The inspectors noted that EP equipment and facilities were satisfactorily maintained in the technical support center (TSC), operations support center (OSC), and emergency operations facility (EOF).

The inspectors observed the post-exercise critique and also determined that the drill was appropriate in scope to be included in the EP performance indicator (PI) statistics. The site drill report and associated DER's which were generated were reviewed. Overall drill performance was reviewed against criteria contained in the Site Emergency Plan.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas

a. Inspection Scope

The inspector reviewed the high radiation area radiological access controls associated with the transfer of a high radiation waste container from the Unit 2 radwaste storage pit to the associated radwaste truck-lock for shipment preparation conducted on October 22, 2002. Pre-job As Low As is Reasonably Achievable (ALARA) discussions and locked high radiation area entries and postings for this work activity were observed as well as implementation of the radiological controls specified by radiation work permit (RWP) 39, Task 10. This review was with respect to the high radiation area entry requirements specified in Technical Specification 6.12, 10 CFR 20.1601 and applicable radiation surveys.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls

a. Inspection Scope

The inspector reviewed licensee ALARA performance during the Spring 2002 Unit 2 8th refueling and inspection outage. The overall exposure performance of 269.5 person-rem was 45 percent above the outage estimate of 185.5 person-rem. Areas reviewed included an evaluation of radiation work permit (RWP) exposure estimates and actual RWP exposure results for the following 9 outage work activities that resulted in greater than 5 person-rem and were also greater than 50 percent above exposure estimate.

- Drywell under-vessel work activities
- Drywell snubber and strut activities
- Drywell safety relief valve maintenance
- Drywell radiation protection operations
- Drywell minor maintenance
- Hydraulic control unit valve maintenance
- Drywell head vent duct modification
- Reactor building/turbine building/suppression pool leak rate tests
- Drywell operations activities

The Nine Mile Point Unit 2 8th Refuel Outage Radiation Protection Report, radiation work permit data records, ALARA post-job reviews, and interviews with the radiological engineering staff regarding exposure estimating methods, were utilized to perform the review. Recent radiological source term dose rate data of the Unit 2 recirculation system and other vessel piping were also reviewed. The inspection review criteria utilized for this inspection area was with respect to the ALARA requirements in 10 CFR 20.1101(b).

b. Findings

.1 Introduction: A Green finding was identified in that Unit 2 outage exposure exceeded estimated exposure by greater than 50 percent. During the Spring 2002 Unit 2 refueling outage, under-vessel work activities resulted in a collective exposure of 47.2 person-rem based on 18 person-rem estimated for the work activities. The exposure overrun was due to inexperienced and poorly trained personnel, and vendor equipment problems.

Description: During the Spring 2002 Unit 2 refueling outage, the under-vessel work was performed by a contractor that had not previously performed these services at Nine Mile Point. The performance deficiency identified in the licensee's ALARA post-job review indicated the contracted workforce was inexperienced, poorly trained, understaffed, and ran into numerous equipment problems due to first-time use at Nine Mile Point.

Analysis: The occupational radiation safety significance determination process specifies screening criteria for more than minor significance to be a work activity exposure greater than 5 person-rem and greater than 50 percent above estimate. After giving credit for higher dose rates than expected in the under-vessel area (9.5 person-rem), this work activity was 72 percent above a 27.5 person-rem adjusted estimate. Nine Mile Point's three-year-rolling-average (1999-2001) is 179 person-rem, which is below the SDP criteria of 240 person-rem for Boiling Water Reactors (BWRs), therefore, this finding is of very low safety significance.

Enforcement: The ALARA rule contained in 10 CFR 20.1101(b) Statements of Consideration indicates that compliance with the ALARA requirement will be judged on whether the licensee has incorporated measures to track and, if necessary, to reduce exposures and not whether exposures and doses represent an absolute minimum or whether the licensee has used all possible methods to reduce exposures. The overall exposure performance of the nuclear power plant is used to determine compliance with the ALARA rule. Since Nine Mile Point is below the three-year-rolling-average of 240 person-rem, no violation of 10CFR20.1101(b) has occurred.

.2 Introduction: A Green finding was identified in that Unit 2 outage exposure exceeded estimated exposure by greater than 50 percent. During the Spring 2002 Unit 2 refueling outage, hydraulic control unit valve maintenance work activities resulted in a collective exposure of 6.91 person-rem based on 1.8 person-rem estimated for the work activities. Two performance deficiencies were identified.

Description: During the Spring 2002 Unit 2 refueling outage, the hydraulic control unit maintenance work resulted in collective exposures 283 percent above the exposure estimate due to two performance deficiencies. As identified in the licensee's ALARA post-job review, the exposure overrun was due to an 83 percent increase in work-hours and exposure due to the improper installation of 139 solenoid operated valve spring clips and air supply hoses that required rework. In addition, after the scram at the start of the outage, rather than isolating and draining the scram discharge volume (SDV) piping immediately after the scram, as is typically done, the licensee left the SDV connected and pressurized to the reactor coolant system in preparation for a outage in-service test. Although leaving the SDV connected to the reactor coolant system was a planned evolution, radiation protection personnel were not involved in the planning activities. This resulted in 73 percent higher dose rates during HCU maintenance due to an outage crud burst spreading into the SDV piping.

Analysis: The occupational radiation safety significance determination process specifies screening criteria for more than minor significance to be a work activity exposure greater than 5 person-rem and greater than 50 percent above estimate. As the increased dose rates were due to licensee's actions, no credit was given for increased dose rates. The hydraulic control unit work activities resulted in 6.91 person-rem, and was 283 percent greater than the estimate. Nine Mile Point's three-year-rolling-average (1999-2001) is 179 person-rem, which is below the SDP criteria of 240 person-rem for BWR's, therefore, this finding is of very low safety significance.

Enforcement: The ALARA rule contained in 10 CFR 20.1101(b) Statements of Consideration indicates that compliance with the ALARA requirement will be judged on whether the licensee has incorporated measures to track and, if necessary, to reduce exposures and not whether exposures and doses represent an absolute minimum or whether the licensee has used all possible methods to reduce exposures. The overall exposure performance of the nuclear power plant is used to determine compliance with the ALARA rule. Since Nine Mile Point is below the three-year-rolling-average of 240 person-rem, no violation of 10CFR20.1101(b) has occurred.

4. OTHER ACTIVITIES (OA)

4OA1 Performance Indicator (PI) Verification

.1 Annual Inspection

a. Inspection Scope

The inspectors sampled licensee submittals for the performance indicators (PI's) listed below for the period from September 2001 through September 2002. To verify the accuracy of the PI data reported during that period, PI definitions and guidance contained in Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Indicator Guideline," Rev. 2, were used to verify the basis in reporting for each data element. Data for both units was reviewed.

Reactor Safety Cornerstone

- Unplanned Scrams per 7,000 Critical Hours PI
- Scrams with a Loss of Normal Heat Removal PI
- Unplanned Power Changes per 7000 Critical Hours PI

The inspector reviewed a selection of Licensee Event Reports (LERs), portions of Unit 1 and Unit 2 operator log entries, daily morning status reports (including the daily DER descriptions), the monthly operating reports, monthly maintenance rule reports and PI data sheets to determine whether the licensee adequately identified the number of scrams and unplanned power changes greater than 20 percent that occurred during the previous four quarters. This number was compared to the number reported for the PI during the current quarter. The inspectors also verified the accuracy of the number of critical hours reported and the licensee's basis for crediting normal heat removal capability for each of the reported reactor scrams. In addition, the inspectors also interviewed licensee personnel associated with the PI data collection, evaluation, and distribution.

- Safety System Unavailability - Emergency AC Power System PI
- Safety System Unavailability - High Pressure Injection System PI
- Safety System Unavailability - Heat Removal System PI
- Safety System Unavailability - Residual Heat Removal PI
- Safety System Functional Failures PI

The inspector reviewed a selection of LER's, portions of Unit 1 and Unit 2 operator log entries, daily morning status reports (including the daily DER descriptions), the monthly operating reports, monthly maintenance rule reports and PI data sheets to determine whether the licensee adequately identified safety system unavailability and functional failures. In addition, the inspectors also interviewed licensee personnel associated with the PI data collection, evaluation, and distribution.

- Reactor Coolant System Activity PI
- Reactor Coolant System Identified Leak Rate PI

The inspector reviewed portions of Unit 1 and Unit 2 operator log entries, daily morning status reports (including the daily DER descriptions), and PI data sheets to determine whether the licensee accurately reported reactor coolant system activity and identified leak rate. In addition, the inspectors also interviewed licensee personnel associated with the PI data collection, evaluation, and distribution.

Occupational Radiation Safety Cornerstone

- Occupational Exposure Control Effectiveness PI

The inspector reviewed occupational exposure-related condition reports, radiologically controlled area (RCA) personnel exit dose data, and dosimetry evaluation reports pertaining to the applicable time period, for occurrences involving locked high radiation areas, very high radiation areas, and unplanned personnel exposures covering the fourth quarter 2001 through the third quarter 2002, against the specified criteria.

Public Radiation Safety

- RETS/ODCM Radiological Effluent Occurrences PI

The inspector reviewed the following documents to ensure the licensee met all requirements of the performance indicator from the first quarter 2001 through the second quarter 2002 (6 quarters):

- monthly projected dose assessment results due to radioactive liquid and gaseous effluent releases;
- quarterly projected dose assessment results due to radioactive liquid and gaseous effluent releases; and
- associated procedures.

The inspector also performed an independent verification of the licensee's capability for calculating projected doses to the public resulting from discharges of radioactive liquid, gases, and particulate using the licensee's meteorological monitoring data. The licensee used its computer code for radioactive gas releases. The NRC used the NRC PC-DOSE computer code. A comparison of the results were evaluated.

b. Findings

No findings of significance were identified.

.2 Followup to Supplemental Inspection for White Performance Indicators Report 50-220/02-009, 50-410/02-009

The supplemental inspection found that since corrective actions for the unavailability of HPCI in Unit 1 had not been implemented at the time of the inspection, it was inappropriate for NMPNS to reset the fault exposure hours at that time. NMPNS has since entered the HPCI controller and logic modules into their preventive maintenance scheduling system to schedule replacement of capacitors. This is to ensure that electrolytic capacitors are replaced prior to their expected end of life. This action satisfies the NEI 99-02 guidance for corrective actions to prevent recurrence of the condition which caused the fault exposure hours to accrue. The inspectors determined that it is now acceptable for NMPNS to reset the fault exposure hours for the HPCI system unavailability which were related to capacitor failures.

4OA2 Identification and Resolution of Problems

.1 Occupational Radiation Safety

a. Inspection Scope

The inspector reviewed sixteen Deviation Event Reports (DERs) that were initiated from October 2001 through October 21, 2002 and were associated with the occupational radiation safety cornerstone. The purpose of the review was to evaluate the licensee's effectiveness at properly identifying, characterizing, investigating, and resolving problems in implementing the licensee's radiation protection program.

b. Findings

No findings of significance were identified.

.2 Uninterruptible Power Supply Failures

a. Inspection Scope

The inspector reviewed DER NM-2002-3038, and NM-2002-3101 to ensure that the corrective actions for the associated plant issues were appropriate. These issues were selected for follow-up review due to their potential safety significance. The DER's addressed the failure of a 200 ampere fuse in one of the Unit 2 uninterruptible power supply (UPS) units. The failures, on June 29 and July 5, 2002, resulted in the loss of the inverter section of the UPS and the plant entering a 24-hour limiting condition for operation (LCO). The issue was documented in NRC Inspection Report (IR) 50-410/01-005.

The inspector reviewed the circumstances surrounding the event, the identification process, and the event evaluation performed by the licensee, including the apparent cause. The inspector verified that the corrective actions were commensurate with the significance of the issue, reasonable, adequately supported by the licensee's conclusions, and correctly implemented. The inspector also reviewed the licensee's evaluation of extent of condition, timeliness of corrective action, actions to prevent recurrence, and identification of the root and contributing causes of the problem. Lastly, the inspector discussed maintenance and test activities related to the UPS fuse failure and human performance following the event with responsible licensee personnel and conducted a physical inspection of the affected equipment.

b. Findings

At the time of the inspection, the licensee's evaluation was still incomplete because the analysis of potentially faulty components by the UPS vendor was still ongoing. However based on a review of documents and discussions with the responsible engineering personnel, the inspector concluded that, following the second failure, on July 5, 2002, the licensee initiated reasonable and acceptable actions to correct the deficiency and prevent recurrence.

Prior to the Unit 2 initial startup, during the design/installation/test phase of the UPS units, the vendor recognized the potential for concurrent firing of the power silicon controlled rectifiers and consequent short circuit condition and instituted several design changes. Based on the licensee's review of industry data, the failure mode experienced by Unit 2 was not a common occurrence. Therefore, the vendor design changes were apparently successful and the concern could not be considered to be generic. Based on the above, the inspector also concluded that the fuse failure was of minor safety significance.

.3 Reactor Building Temperature Design Limits

a. Inspection Scope

The inspector selected DER's NM-2002-0691, NM-2001-5873 and NM-2001-5842 for detailed review. DER-NM-2002-0691 identified an issue in which the reactor building temperature may have been outside the design limit during a postulated Appendix R event. DER-NM-2001-5873 identified an issue that past operability of the emergency core cooling system (ECCS) and reactor core isolation cooling (RCIC) had not been previously evaluated in a previous DER. DER-NM-2001-5842 identified an issue that engineering supporting analysis (ESA) contingency actions were not proceduralized in a timely fashion. The inspector reviewed these DER's to ensure that the full extent of the issue was identified, that appropriate evaluations were performed, that appropriate extent of condition reviews were performed, and that appropriate corrective actions were specified and prioritized. For corrective actions not completed, the inspector verified an appropriate plan was in place to resolve the issues. Additionally, the inspector reviewed cause evaluations, and effectiveness and adequacy of specified corrective actions. Verification that the corrective actions were implemented prior to closing the reviewed DER's was also accomplished. The inspector reviewed completed performance evaluation tests for unit coolers in the north/south auxiliary electrical rooms (Unit 2 reactor building) to ensure that the systems met their requirements and functioned as designed. Additionally, the inspector reviewed the Unit 2 reactor building heating, ventilating and air conditioning (HVAC) system health reports to determine current system status.

During review of the above DER's, the inspector noted many issues associated with reactor building HVAC. The inspector questioned the licensee on their plans to resolve these issues. The inspector reviewed the Unit 2 top ten issues report to determine if the issues identified with the reactor building HVAC system were being appropriately tracked for resolution. Additionally, the inspector interviewed the Unit 2 reactor building HVAC system project manager to determine what plans were in place to address and resolve the various issues.

Additionally, the inspector toured the north/south auxiliary bay electrical rooms of the Unit 2 reactor building to assess material condition of the unit coolers and the motor control centers (MCC's). The inspector also interviewed systems and design engineering personnel to determine their familiarity with the issues inspected and to gain insights on how the issues would be resolved.

b. Findings

No findings of significance were identified. The inspector found that the corrective actions associated with the reviewed DER's were appropriate and were acceptable upon completion. Cause evaluations, engineering evaluations and operability determinations were detailed and thorough. The inspector also found that the licensee appropriately conducted extent of condition reviews for the reviewed issues. No operability concerns were identified. Additionally, the inspector found that the licensee had placed the Unit 2 reactor building HVAC system on the Unit 2 top ten list and had appropriate plans in place to address several unit reactor building HVAC system issues by the end of May 2003.

4OA3 Event Followup

.1 Reactor Scram due to Main Steam Isolation Valve Closure

a. Inspection Scope

At 5:15 a.m. on November 11, 2002, Unit 2 automatically scrammed from 100 percent power due to high reactor vessel pressure, caused by the unexpected, sudden closure of a main steam isolation valve (MSIV). Initially, one MSIV closed due to disc/stem separation; the ensuing pressure pulse caused a high steam flow condition, which was sensed in the other three main steam lines resulting in automatic closure of the other seven inboard and outboard MSIV’s, as designed. The inspector responded to the site and observed control room operator response including use of emergency operating procedures. As part of the follow up to this event, the inspectors reviewed plant chart recorders, compared procedure requirements to observations of operator performance and held discussions with plant personnel regarding operator control of critical plant parameters. Plant and operator response was consistent with design and procedures. The event was of low safety significance because all mitigating systems performed as designed, and the MSIVs could have been reopened and condenser cooling restored. The licensee documented the event in DER NM-2002-4811.

In the early 1990s, Unit 2 determined that a modification was not required to prevent separation events based on the valve design that included a 60 percent valve stroke and that no industry failures had occurred on valves with this stroke length. Vendor information also stated that the Unit 2 MSIVs contained the improved stem/stem-disc and main disc/piston connection. However, Unit 2 did evaluate a new modified stem/stem-disc assembly design as an improvement to further minimize any potential of separation. The improved design was implemented as a contingency based on local leak rate test (LLRT) performance of the MSIVs. Vendor recommendations for maintenance and inspection state that inspections of valve internals should only be performed when the valve is required to be disassembled for other purposes. Therefore, Unit 2 decided to modify the valve internals only when they failed the LLRT testing. During subsequent outages, by the mid 1990s, five of eight valves had been modified following LLRT failures. During the December 2002 shutdown, the licensee corrected the condition or verified that the valve configuration was acceptable, for the remaining three MSIV’s.

b. Findings

No findings of significance were identified.

.2 Automatic Scram Initiated by Main Generator Stator Water Cooling System Runback

a. Inspection Scope

At 3:47 p.m. on December 16, 2002, Unit 2 automatically scrammed from 71 percent power due to high reactor pressure. The event was initiated by a main electrical generator stator water cooling system load set runback due to the failure of the stator cooling water temperature control valve. The control valve failure to the minimum cooling position was caused by a failure of the feedback mechanism. Immediate investigation found the stator water temperature controller fully downscale. This caused the controller output to drive the temperature control valve to the full bypass position, bypassing the heat exchangers and removing the cooling normally provided to the main generator. The inspectors responded to the control room and observed control room operator response including use of emergency operating procedures and control of plant parameters. As part of the follow up to this event, the inspectors reviewed plant chart recorders, compared procedure requirements to observations of operator performance and held discussions with plant personnel regarding operator control of critical plant parameters. In addition, the inspectors reviewed the licensee's post scram review documentation, and reviewed the root and contributing causes for the controller failure. The event was of low safety significance because all mitigating systems performed as designed. The licensee documented the event in DER's NM-2002-5312 and 5314.

Generator stator temperature is controlled by a three-way bypass valve which controls the amount of stator water passing through a set of coolers. The bypass valve is controlled by a temperature controller with internal mechanical linkage. The mechanical link failed at the linkage connection causing the controller to sense a false low temperature. Corrective actions included replacing the controller and relocating it to an area with less vibration; the Unit 1 controller was also replaced.

b. Findings

No findings of significance were identified.

4OA5 Other

a. Inspection Scope

An audit of the licensee's performance of the interim compensatory measures imposed by the NRC's Order Modifying License, issued February 25, 2002, was completed in accordance with the specifications of NRC Inspection Manual Temporary Instruction (TI) 2515/148, Revision 1, Appendix A, dated September 13, 2002.

b. Findings

No findings of significance were identified.

4OA6 Management Meetings

Exit Meeting Summary

The inspectors presented the inspection results to Mr. J. Conway, Vice President, Nine Mile Point, and other members of licensee management at the conclusion of the inspection on January 10, 2003. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT 1

a. Key Points of Contact

Licensee

M. Alexander, Operations Training
G. Bridges, Requalification Supervisor, Unit 2
J. Conway, Vice President Nine Mile Point
R. Dean, General Supervisor, Design Engineering
G. Detter, Manager, Support Services
L. Hopkins, Plant General Manager
J. Jones, Supervisor, Emergency Preparedness
S. Minahan, Manager, Unit 2 Operations
B. Montgomery, Manager, Engineering Services
M. Navin, Manager, Nuclear Training
M. Peckham, Manager, Work Control/Outage Management
B. Randall, General Supervisor, System Engineering
V. Schuman, Radiation Protection Manager
J. Stewart, Requalification Supervisor, Unit 1
C. Terry, Manager, Quality and Performance Assessment
R. Thurow, Operator Training General Supervisor
D. Topley, Manager, Unit 1 Operations
D. Wolniak, General Supervisor, Licensing

b. List of Items Opened, Closed and Discussed

Opened

50-220/2002-06-01	URI	Apparent EOP procedure inadequacy did not allow execution of EOP-2, "RPV Control steps L-3 and L-7 to restore and then maximize injection using all preferred sources which include condensate/FW
50-220/2002-06-02	URI	Corrective Actions for Reactor Building Closed Loop Cooling System Degradation

c. List of Documents Reviewed

Nine Mile Point Unit 2 2002 Post Refueling Outage Radiation Protection Report
Unit 2 Spring 2002 Outage ALARA post-job reviews: Drywell Operator Rounds and Markups, Drywell In-Service Inspections, Suppression Pool Cleanup Project, Drywell Snubber Activities,
Refuel Floor and RPV Activities, Drywell Minor Maintenance, Drywell Radiation Protection Operations, Hydraulic Control Unit Maintenance, Drywell Head Vent Duct Modification

Vendor Data:
Elgar 634-058-90 Revision B to UPS 253-1-106 Instruction Manual (Operations - Maintenance Instructions and Parts Catalog for Elgar Uninteruptible Power System (UPS) Model UPS 253-1-106
Elgar Pt 5490001-01 Engineering Change Notice Summary

Drawings:
643-523-60, Rev. D Inverter Panel Schematic
EOC 2E10371 Melting Time-Current Data - A50P Fuses, 10 - 1000 Amperes, 500 Volts

Calculations:

S13.4-70-HX02	RBCLC HX Thermal Performance Evaluation
S13.4-70-HX02-2A	RBCLC HX Thermal Performance Evaluation Disposition
S13.4-70-HX02-2B	RBCLC HX Thermal Performance Evaluation Disposition
S13.4-70-F007	RBCLC System Thermal/Hydraulic Analysis
S13.4-70-F007-2A	RBCLC System Thermal/Hydraulic 10 Hour shutdown Analysis
S13.4-70-F007-2B	RBCLC System Thermal/Hydraulic 10 Hour shutdown Analysis
S13.4-70-F007-2C	RBCLC System Thermal/Hydraulic Analysis
S13.4-70-HX06	RBCLC TCV-70-137 Minimum Position and Wintertime Supply
EC-072	Heat Release, Reactor Building Secondary Containment, Rev. 5
EC-076	Heat Release in Reactor Building Auxiliary Bay, Rev. 3 & 4
HVR-056	MCC Room Temperature Response Following a Control/Relay Room Fire (Appendix R) Without The Unit Cooler, Rev.1

Temperature Evaluation:

HVP-6	Standby Diesel Generator Building Control Room Cooling Load and Unit Cooler Sizing
HVP-012	Performance of Diesel Generator Building Unit Coolers
S13.4-70-F010	NMP 1 Reactor Building Closed Loop Cooling Heat Exchanger - Failure Analysis Report MPR-1197

Licensing Documents:
Nine Mile Point Unit 2 Technical Specifications
Updated Safety Analysis Report - Nine Mile Point Unit 2 Nuclear Station
Design Basis Document - Appendix R, Appendix R Safe Shutdown System, Rev. 5

Deviation Event Reports:

2002-4547	2002-2181	2002-1167	2001-5104
2002-479	2002-1473	2002-1605	2002-1606
2002-1607	2002-1702	2002-1703	2002-1827
2002-1939	2002-1940	2002-1941	2002-1944
2001-4634	2001-4804	2001-5842	2001-5873
2002-0691			

Training Documents:

TCO OPS2-2002-31,	Review and Determine All Scenarios Affected by N2-OP-52 Change, 2/26/02
TCO OPS2-2002-32,	Add New 288-942-04-01 "Operation of ECCS Pump Room Unit Coolers Following Automatic Initiation Signal" to HVR LP, 2/26/02
TCO 02-OPS-2001-349,	Needs Analysis Based on Changes to NP-OP-52, 12/21/01

TRR 2001-1075,	Provide on Shift Training to Control Room Staff on Changes to NP-OP-52 and The Reasons for it, 12/14/02

Procedures:

N2-ARP-01,	Control Room Alarm Response Procedure, Rev. 0
N2-OP-52,	Reactor Building Ventilation, Rev. 6
N2-OP-78,	Remote Shutdown System, Rev. 10
N2-TTP-HVR-@408,	Performance Evaluation Test for Unit Cooler 2HVR*UC408A and B, Completed 1/9/01 and 1/16/01
N2-TTP-HVR-@409,	Performance Evaluation Test for Unit Cooler 2HVR*UC409A and B, Completed 1/11/01 and 10/12/01

Engineering Reports and Evaluations:

ESA-2M01-03,	Engineering Support Analysis, 10/9/01
ESB2-E02-0028,	Equivalency Evaluation, 5/16/02
NER-2M-066,	Unit Cooler Performance, Rev. 0
NER-2M-073,	Reactor Building Temperature Response Following and Appendix R Fire in Control/Relay Room, Rev. 0

Miscellaneous Documents:

Health Reports: 3rd and 4th Quarter (2002) Health Reports for Reactor Building Ventilation
Nine Mile Point Unit 2, Top Ten Issue Report - Reactor Building HVAC Project
Night Orders for 12/14/2001
NRC Inspection Report 50-220/01-10, 50-410/01-10

d. List of Acronyms Used

ALARA	As Low As is Reasonably Achievable
BWR	Boiling Water Reactor
CFR	Code of Federal Regulations
CRD	Control Rod Drive
DER	Deviation Event Report
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
ERV	Electromatic Relief Valve
ESA	Engineering Support Analysis
FW	Feedwater
HCU	Hydraulic Control Unit
HVAC	Heating, Ventilation, and Air Conditioning
ICM	Interim Compensatory Measures
LLRT	Local Leak Rate Test
MCC	Motor Control Centers
MDC	Mechanical Design Criteria
MSIV	Main Steam Isolation Valve
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
PI	Performance Indicator
RBCLC	Reactor Building Closed Loop Cooling
RRMG	Reactor Recirculation Motor Generator
SDP	Significance Determination Process
SDV	Scram Discharge Volume

TCP	Temporary Change Package
UPS	Uninterruptible Power Supply
URI	Unresolved Item
USAR	Updated Safety Analysis Report
WO	Work Order