U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 88-16/88-16

Docket No. 50-220/50-410

License No. DPR-63/NPF-69

Licensee: Niagara Mohawk Power Corporation
301 Plainfield Road
Syracuse, New York 13212

Facility: Nine Mile Point, Units 1 and 2

Location: Scriba, New York

Dates: May 25, 1988 through July 6, 1988

Inspectors: W.A. Cook, Senior Resident Inspector
W.L. Schmidt, Resident Inspector
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Approved by: Jon R Johnson 7/22/88
J.R. Johnson, Chief, Reactor Projects Section 2C, DRP — Date

INSPECTION SUMMARY

Areas Inspected: Routine inspection by the resident inspectors of station activities including Unit 1 outage and Unit 2 power operations, licensee action on previously identified items, plant tours, safety system walkdowns, surveillance testing reviews, maintenance reviews, TMI Action Plan review, allegation followup, and NRC Bulletin review. This inspection involved 280 hours by the inspectors which included 35 hours of backshift inspection coverage.

Results: No violations or unresolved items were identified. A discussion of the Unit 2 Standby Gas Treatment system decay heat removal mode of operation design deficiency is provided in Section 1.2.e. Followup inspection of the Unit 1 fire barrier penetration concern is discussed in Section 2.1.b. A NYS Attorney General inquiry of a potential OSHA violation is discussed in Section 10.1. Preliminary licensee review of NRC Bulletin 88-05 is discussed in Section 11.

DETAILS

1. Review of Plant Events (71707,93702,90712,71710)

1.1 UNIT 1

During the inspection period the unit remained shutdown for the 1988 refueling outage. Core reload has not yet begun due to continuing Inservice Inspection (ISI) Program implementation evaluations.

a. On May 19, GE issued Rapid Information Communication Service Information Letter (RICSIL) No. 019 dealing with crack indications found on Control Rod Drive (CRD) cap screws. Based on this information and a previously missed ISI examination the licensee removed and inspected all CRD flange bolts. The results of this comprehensive inspection including the following: fifteen bolts had visual (VT) indications (corrosion, pitting or potential cracking) and four of these had penetrant testing (PT) indications (minor cracking). All fifteen bolts were replaced.

b. June 30 the licensee reported to the NRC via the ENS that they had lost a small quantity of special nuclear material (six milligrams of U-235). The licensee had initiated an audit of their special nuclear materials based upon review of NRC Information Notice 88-34. Unit procedures require an annual audit; however, the licensee believed it was a good initiative, even though the last inventory was done in January 1988.

The U-235 was contained in four non-irradiated local power range monitor (LPRM) fission chambers which had been removed from the LPRM string assembly and packaged for permanent storage. The licensee has conducted a thorough search, without success, and has concluded that the package of 18 inch wire-like fission chambers was mistakenly disposed of as radioactive trash. The inspectors will review licensee corrective actions in a subsequent inspection.

1.2 UNIT 2

During this period the unit was shutdown until May 30 while replacing the A recirculation pump seal. On June 2 a reactor scram occurred due to the mechanical failure of the 10A feedwater control valve feedback linkage. The reactor was taken critical again on June 4 and operated at near rated power until another reactor scram on June 22 due to the malfunction of the 10C feedwater control valve. In addition to troubleshooting and repair of the feedwater control valves, the licensee had to repair a generator stator cooling coil leak discovered during operator rounds prior to restart. During the reactor startup on June 28, the reactor scrammed from 13 percent power due to operator error involving a pressure transient caused by inadequate control of steam loads. The reactor was restarted on June 30 and operated at power through the end of the inspection period.

a. On May 10, the licensee determined that the water level setpoints used for the RCIC and HPCS suction transfer to the supression pool from the condensate storage tanks were not conservatively set with respect to the Technical Specifications limit. The reason for the error was that the velocity head of the water passing the level detectors was not taken into account. These level setpoints were previously called into question and a VIOLATION of Technical Specifications was issued as documented in Inspection Report 50-410/87-45. During the inspector's earlier review of the calculations the licensee was specifically asked if the velocity head was taken into account. The licensee representatives replied that it was taken into account with the piping head loss. The inspector reviewed the licensee's revised calculations and corrective actions and determined them to be adequate.

b. On June 2 at 11:23 p.m., a reactor scram occurred as a result of the failure of the position feedback linkage to the 10A feedwater control valve. The metal retaining ring on the lower linkage to the valve position feedback arm failed due to fatigue, resulting in the 10A control valve going full open. The increased feedwater flow caused a reactor vessel level rise and accompanying power increase to approximately 30%. The reactor vessel level eight (8) turbine trip signal was received resulting in a reactor scram due to reactor power being greater than the turbine bypass valve capacity. The inspector reviewed the licensee's post-trip review and verified all safety systems functioned properly. The licensee repaired the 10A, 10B and 10C control valve linkages with an improved retaining ring. The inspector noted no discrepancies.

c. On June 6 at 2:08 a.m., an inadvertant secondary containment isolation and standby gas treatment (SBGT) system auto-initiation occurred as a result of a spurious radiation monitor trip signal. The spurious trip signal was caused by technician error when an attempt was made to reset the Digital Radiation Monitoring System (DRMS) microcomputer without first bypassing the trip signals (resetting the microcomputer was known to cause spurious trip signals). The inspectors reviewed licensee response to the auto-initiation and subsequent corrective actions and determined them to be adequate. (reference LER 88-24).

d. On June 9 while conducting turbine stop valve surveillance testing the recirculation valve flux controller malfunctioned. Reactor power was reduced via recirculation flow to approximately 90 percent and than the controller was placed back in Automatic. The master controller repositioned the recirc flow control valves automatically to 100 percent even though there was no known input signal. This malfunction was demonstrated under controlled conditions one more time and then, at the direction of the Station Shift Supervisor, the flux controller was tagged in the Manual mode.

The inspector determined that the licensee does not plan to troubleshoot the controller at power due to the potential for another uncontrolled response. A similar such event did occur at the Perry facility in Ohio on June 16, 1988 where the reactor scrammed on high power. Licensee action in addressing this problem has been safe and prudent.

e. On June 12, the licensee declared the B train of Standby Gas Treatment System (SBGT) inoperable after a shift operator noticed that one of the two, in series, charcoal adsorber decay heat removal valves (MOV-28B) was closed and not operable. The applicable Technical Specification (TS) Limiting Condition for Operation (LCO) was entered, requiring that the valve be repaired and the train returned to an operable status within seven days or that a reactor shutdown be commenced within one hour and the plant be in HOT SHUTDOWN within 12 hours and COLD SHUTDOWN within 24 hours.

Detailed licensee review determined that because of a potential single failure (malfunction or power loss resulting in the valve failing shut) of MOV-28B the decay heat removal capability for the B train of SBGT could be affected. Decay heat generated in the charcoal adsorber (due to a fission product load after a LOCA) is removed when the train is operating via the normal system flow. When the train is secured this decay heat is designed to be removed by drawing air through the secured train using the operating train as the motive force. Regulatory Guide (Reg. Guide) 1.52, to which the licensee is committed, requires that the mode of decay heat removal be single failure proof. It was further determined that on a loss of divisional electrical power to one of the SBGT trains its respective decay heat removal air inlet valve (MOV-4A or B) would be inoperable. The licensee reported on June 15, via ENS, that the SBGT system was operating outside the design bases.

Inspector review found that entry into the SBGT LCO action statement, in this instance, was found to be conservative since the A train would be able to remove the heat generated in its absorber using the normal system air flow. Discussions between the NRC Region I and NRR staffs indicted that credit could be taken for the fire supression system installed to put out a fire in the absorber as an acceptable means of removing the decay heat per Regulatory Guide (RG) 1.52. However, dependence on the fire supression system should be for a limited time, until the licensee could effect needed design changes. This interpretation of RG 1.52 was conveyed to the licensee the morning of June 17 and later that day the licensee declared both trains of SGBT operable; taking credit for the fire suppression systems as the primary means of decay heat removal. The design changes were completed prior to restart from the June 22 reactor scram. These changes make the MOV-28 valves fail open on a loss of power and change the power supply of the MOV-4A and B

valves to the opposite divisional power supply (MOV-4A is supplied from Division II and MOV-4B is supplied from Division I) and bring the design into comformance with Regulatory Guide 1.52.

f. On June 22 at 9:39 a.m., a reactor scram occurred from approximately 100% power. The scram was caused by low reactor vessel level resulting from the malfunction and closure of the LV-10C feedwater control valve. The inspector determined that earlier that same morning, the LV-10B control valve was oscillating and reactor power was reduced to place the 10C valve in service and remove the 10B from service for troubleshooting and repair. Reactor power was restored and stabilized at 100% when the 10C valve malfunctioned and closed. The rapid valve closure caused a reactor vessel level decrease to the scram setpoint and resulted in a reactor scram.

Earlier on June 6, a similar malfunction of LV-10C occurred, but did not result in a reactor scram because of prompt action by control room operators to minimize the reactor vessel level swings. The licensee conducted troubleshooting of the 10C control valve, but was unsuccessful in identifying a specific cause of the malfunction. The 10C valve actuator control signals had been closely monitored since this event and no abnormal control signals were observed.

The inspector determined that monitoring equipment connected to LV-10C during the June 22 scram identified no abnormal feedwater control signal inputs. The valve's intermittent malfunction was isolated to the valve actuator. Disassembly and inspection of the actuator control circuit identified numerous loose terminal board stake-ons and poor quality solder connections. The licensee suspects that these problems and the possible fouling of the internal hydraulic control valves contributed to the intermittent valve malfunctions. Verification of the resolution of these actuator problems was performed during testing of the feedwater control valves at low and high reactor power levels. The post-maintenance valve test procedure was taken from the power ascension testing program procedure.

g. On June 28 at 8:12 p.m., while the reactor was in the STARTUP Mode at approximately 7% power, a reactor scram occurred. The cause of the scram was a pressure transient which resulted in a large enough power excursion to cause average power range monitor (APRM) flux high (13%) trips. The cause of the pressure transient was operator error in attempting to place the moisture separator reheater system low flow steam supply valves in service under too low a power level and steaming rate conditions.

The inspector reviewed the post-trip review documentation and licensee corrective actions to prevent recurrence. The operating procedures for the moisture separator reheater (MSR) system (N2-OP-2) and plant startup (N2-OP-101A) have been revised to ensure the MSR trains are left isolated until reactor power is between 15

and 19 percent. This revision is designed to prevent excessive pressure transients while the reactor is operating at low power levels and below normal operating pressures and temperatures. The inspector identified no discrepancies.

Following the reactor scram and because of the minimal decay heat generation rate and too high of a steaming rate, the reactor coolant system cooldown rate exceeded the Technical Specification (TS) limit of 100 degrees F per hour. The maximum calculated cooldown rate was approximately 117 degrees F per hour. Control room operators recognized that the reactor coolant system was cooling down rapidly because of the higher than normal steam loads and closed the outside containment main steam isolation valves to stop the cooldown. During the post trip review the licensee determined that the cooldown rate was exceeded.

The inspector determined that the licensee took appropriate action to comply with the TS action statement, to secure the cooldown and to perform an engineering evaluation to determine the effects of the excessive cooldown rate on the structural integrity of the reactor coolant system. The evaluation was performed by GE and reviewed and approved by the Station Operations Review Committee (SORC). The evaluation concluded, based upon comparison with the cooldown rate calculated for the design basis event (reactor overpressure with delayed scram) that the cumulative fatigue usage of the vessel and its internals was not adversely affected. The inspector noted no discrepancies; however, the operators should have been more sensitive to the reactor cooldown rate and prevented this event. To prevent recurrence the licensee has discussed the lessons learned from this event with all operators and included precautions in the plant shutdown procedure to alert operators to the potential for exceeding the cooldown rates.

The inspectors verified that the licensee made the appropriate 10 CFR 50.72 notifications via the Emergency Notification System for the events discussed above.

2. Followup of Previous Identified Items (71707,64704,62703,93702,92703)

2.1 Unit 1

a. The licensee has determined that the 103 diesel generator internal lube oil relief valve was not oriented in the same manner as the relief valve found on the 102 diesel generator. The orientation of the relief valve on the 102 diesel was believed to have caused high crankcase pressure trips of the machine due to the discharge of the relief valve being directed at the crankcase pressure sensing diaphragm. The potential for improper orientaion of the relief valve has been addressed in the diesel generator maintenance procedure. The inspector found this resolution adequate.

b. (Open) UNRESOLVED ITEM (50-220/88-15-02) Fire barrier penetration installation verifications: During this inspection period the licensee continued walkdowns of fire rated walls looking for discrepancies in sealed penetrations. On June 7 the inspector requested that the licensee provide the necessary documentation to prove that four randomly selected fire barrier penetrations between the cable spreading room and the auxiliary control room were properly sealed. On June 14 the inspector held a meeting with the Engineering personnel tasked to followup on the penetration issue. During that meeting the licensee provided the information requested above. Of the four penetrations selected three had been breached and resealed during the present outage. These penetrations had been resealed by a licensee contractor using appropriate documentation and quality control. The licensee could provide no documentation on the fourth penetration.

Based on these results the inspectors increased their sample size and walked down several fire barriers in the reactor building, turbine building and control building complex looking for Appendix R barrier penetrations which may be suspect. Thirteen penetrations were chosen and the licensee was asked to provide the necessary documentation on these seals. On the last day of the inspection period (July 6) the licensee provided some supporting documentation for these penetrations. This information will be reviewed in a subsequent inspection.

The licensee was informed that any penetration that does not have supporting documentation to affirm the integrity of the penetration seal is potentially in noncompliance with the requirement to have a fully functional and operable fire barrier penetration. Subsequently, during the June 20 restart meeting, the licensee was asked what they were going to do to ensure that these questionable fire barriers were fully functional. The licensee committed to sampling (destructive examination) various types of penetrations using a statistical basis to determine a 95 percent confidence level that the penetrations were properly sealed. The licensee indicated the sample size may be increased, if necessary, to gain confidence in the integrity of the fire barrier penetrations. This item remains unresolved pending additional review of the corrective actions to evaluate and repair the fire barriers.

c. (Open) UNRESOLVED ITEM (50-220/88-08-03) Primary Containment Penetration Local Leak Rate Testing (LLRT): On May 4 while performing LLRT on containment penetrations, I&C technicians noted that they were not testing several penetrations which had test connections on then. An Occurrence Report (OR) was written at the time to document this observation. The OR was evaluated as not requiring a thirty day LER because the penetrations were of the welded type, which do not require LLRT per 10 CFR 50 Appendix J. However, Technical Specification (TS) 4.3.3.e.(1) requires that

primary containment testable penetrations be tested at a pressure of 35 psig at each major refueling outage. To resolve this discrepancy the licensee has committed to making a TS amendment that clearly states that welded penetrations need not be tested by LLRT and only by Integrated Leak Rate Testing. This item remains open pending final review and approval of the TS amendment.

d. (Closed) INSPECTOR FOLLOWUP ITEM (50-220/78-CI-07): IE Circular 78-07: Damaged Components on a Bergen-Paterson Series 25000 Hydraulic Test Stand. This circular describes a concern that snubber test results may be adversely influenced by the use of damaged components in the hydraulic test stand. The circular also states that the loading conditions creating this problem do not occur on strut assemblies that incorporate ball bushings in the cross-piece connections. These bushings ensure translation of pure axial movement in the test stand.

The inspector determined that the test stand used at Unit 1 was designed by Niagara Mohawk Engineering and is not a Bergen-Paterson design. Their test stand does incorporate ball bushings in the cross-piece connection ensuring pure axial movement. This item is closed.

2.2 Unit 2

a. (Closed) UNRESOLVED ITEM (50-410/87-20-03): High Pressure Core Spray System (HPCS) high reactor water level seal-in reset relay lead lifted. On July 2, 1987 the licensee determined that one seal-in relay lead to the HPCS high reactor water level reset had been lifted for approximately four months. The licensee determined that two leads were lifted during the previous month's surveillance test and that one lead was not relanded after the test was completed. The procedure requiring the leads to be lifted was not clear and was revised to specify that two leads be lifted and that two leads be relanded with a second person verification. The inspector determined that this event would not have caused HPCS to be inoperable, but would have resulted in the injection valve cycling shut and open unnecessarily when the high level signal came in and then subsequently cleared. This item is resolved.

b. (Closed) UNRESOLVED ITEM (50-410/87-39-01): Potential insufficient reactor building-to-outside air differential pressure setpoints. The inspector has reviewed the licensee's interim corrective action which changes the differential pressure setpoint to negative 0.7 inch of water. The final design change moves the differential pressure detectors to a sensing point at the top of the reactor building with the old setpoint of negative 0.25 inch of water. Both solutions were acceptable and the inspector had no further questions. This item is resolved.

3. Plant Inspection Tours (71707,71710,62703,64707,71881,71709)

During this reporting period, the inspectors made tours of the Unit 1 and 2 control rooms and accessible plant areas to monitor station activities and to make an independent assessment of equipment status, radiological conditions, safety and adherence to regulatory requirements. The following were observed:

3.1 Unit 1

On June 7, during a routine plant tour the inspector noted that the #12 service water pump upper motor bearing was hot to the touch. This condition was reported to the control room and the process computer alarm point was found to be in the alarm condition at 180 degrees F (alarm setpoint is 160 degrees F). The inspector determined that the elevated bearing temperature was caused by the low flow condition during the present outage. To correct this condition a temporary jumper feeding cooling water to the bearing was installed. See section 12 for additional discussion.

3.2 Unit 2

During the surveillance review discussed below in Section 4.2, the inspector noted that the B service water pump was operating with the installed pump bearing temperature sensors removed. These sensors provide input to the process computer which provides an annunciated alarm in the control room for high bearing temperature. The inspector determined that the B service water pump had been returned to service without these detectors in operation. In addition, the inspector determined that the control room operators were aware of the detectors being out of service and had increased the frequency of operator rounds in the area to check pump operation. The inspector observed that there was no Equipment Status Log entry to formalize the required compensatory measures. When this observation was brought to Operations Department management attention the pump was secured and the temperature detectors restored prior to placing the pump back in service.

No violations were identified. Additional review of the pump protection instrumentation will be performed during future inspections.

4. Surveillance Review (61726)

The inspectors observed portions of the surveillance testing listed below to verify that the test instrumentation was properly calibrated, approved procedures were used, the work was performed by qualified personnel, limiting conditions for operations were met, and the system was correctly restored following the testing.

4.1 Unit 1

a. On May 27 the inspector observed the first attempt to local leak rate test (LLRT) the new feedwater check valve 31-01 in accordance with procedure N1-ISP-R-031-501. The valve failed to pressurize because of excessive debris on the valve seat. The inspector determined that following installation of the valve it was not flushed. Apparently the modification and installation package did not address a post-installation flush or cleaning. Subsequently, the licensee conducted flushes of the new check valve and the valve passed the LLRT. With the exception of the test failure, the inspector observed no discrepancies with the conduct of the leak test.

b. On May 31 and June 9 the inspector observed the conduct of electromatic relief valve (ERV) and steam piping hydrostatic testing in accordance with procedure N1-ISI-HYD-402. No discrepancies were noted; however, the inspector questioned the licensee as to whether or not the correct hydrostatic test boundary for the individual ERVs was established. The licensee subsequently provided the inspectors with the vendor testing specification which clearly identifies the test boundary and which was properly reflected in the test procedure.

While observing the hydrostatic testing of the ERVs in the decontamination room, the inspectors noted the poor state of housekeeping in that work space. This observation was brought to the attention of station management for action and it was subsequently corrected.

c. On June 28, the inspectors met with licensee representatives to discuss a commitment made by the licensee to the NRR staff during a meeting on June 9, 1988 to discuss exemptions to 10 CFR 50, Appendix J. Based upon the current containment spray system configuration, it is impractical to perform local leak rate testing of the system containment isolation valves. Therefore, the licensee committed to establish a water seal on the containment spray inlet discharge isolation valves for the containment spray loop(s) that are not in operation, following a Loss of Coolant Accident (LOCA). The licensee presented the revised System Operating procedure (N1-OP-14) to the inspectors for their review. No discrepancies were noted with the revision or water sealing method; however, the inspectors identified a few items requiring further licensee action. The action items include a revision to the annunciator response procedure, a revision to the system (loop) shutdown procedure and the need to conduct operator training on all of the procedural revisions. The licensee indicated these items would be reviewed and appropriate action taken. The inspectors will review those actions in a subsequent inspection period.

4.2 Unit 2

a. During this inspection period, the inspector asked the licensee to provide information and a demonstration of the types of equipment planned for use in Inservice Testing (IST) Program applications. As part of this review, the inspector requested that an IST inspector take vibration readings on operating equipment. One component tested was the B service water pump. The pump was found to have vibration in the alert range in the axial direction at the pump outboard bearing. The same results had been documented in the quarterly pump operability check (N2-SWP-Q002) on May 22, prior to the pump being returned to service.

The inspector observed that the vibration monitor being used was a hand held vibration analyzer which records vibration data and then outputs the stored data to a data base on a computer in the IST office. The computer data collection program allows for trending and spectrum analysis of vibration data. The inspector noted that the responsible IST personnel were knowledgeable and qualified in the use of the vibration collection and analysis equipment. No discrepancise were noted.

b. On July 2 the inspector observed the post maintenance testing of the feedwater control valves LV-10A and 10C in accordance with N2-IMP-FWS-@001, Feedwater Control System Tuning. The valve testing was to evaluate the corrective maintenance performed on the feedwater control valves following the malfunction of LV-10C on June 28 which resulted in a reactor scram. The inspector discussed the various aspects of the test with the responsible test engineer and control room operators. The testing performed appeared to be adequate in exercising the proper operation of the valves at normal feedwater flow conditions and reactor power levels. No discrepancies were noted.

5. Maintenance Review (62703)

The inspector observed portions of various safety-related maintenance activities to determine that redundant components were operable, that these activities did not violate the limiting conditions for operation, that required administrative approvals and tagouts were obtained prior to initiating the work, that approved procedures were used or the activity was within the "skills of the trade", that appropriate radiological controls were implemented, that ignition/fire prevention controls were properly implemented, and that equipment was properly tested prior to returning it to service.

5.1 Unit 1

Based on the fire barrier penetration issue discussed in Section 2.1.b above, the inspector reviewed the licensee's procedures for restoring emergency electrical power in the event of a fire in a safe shutdown area

coincident with a loss of offsite power. These procedures are referred to as Damage Repair Procedures. Each procedure addresses a different area and specifies the repairs that might be needed if a fire damaged both emergency diesel power supplies. The types of repairs directed are specific to return one of the two diesel generators to service with one control rod drive pump operable to charge to the reactor vessel within eight hours and to restore shutdown cooling to the core within 72 hours. The equipment and tools needed are on site to complete these tasks. Personnel have been trained to perform the needed operations and have walked down the areas. The inspector requested, and the licensee has committed, to review the potential for including one of these procedures during the next Unit 1 Emergency Response drill to demonstrate the practicality of implementing these procedures under drill scenario conditions.

5.2 Unit 2

a. The inspector reviewed the licensee's root cause analysis report for the May 23, 1988 catastrophic failure of the A recirculation pump seal. The report was well-organized and listed several good recommendations for preventing a subsequent failure. The inspectors also examined the failed seal and discussed the failure mechanism with the station mechanical maintenance superintendent. No deficiencies were noted.

b. The inspector reviewed Temporary Modification 88-159 which defeated the thermal shock and cavitation interlock for the B recirculation pump. The interlock was defeated because both the normal and spare pump suction thermocouple (B35-N028B and N023B) inputs to the interlock had failed and could not be readily replaced. The thermal shock and cavitation interlock prevents undue stresses on the vessel nozzles and bottom head region and helps ensure sufficient net positive suction head to prevent pump cavitation. The inspector reviewed the 10 CFR 50.59 Safety Evaluation (88-050), the lifted lead controls and the revised operating procedure (N2-OP-29, Reactor Recirculation System) which addresses actions to be taken for starting and upshifting the B recirculation pump with defeated thermal and cavitation interlocks. These compensatory actions were also discussed and walked through with a control room operator. No discrepancies were noted.

c. On June 14 the inspector observed work being conducted on Standby Gas Treatment train B decay heat removal crosstie valve (MOV-28B). The mechanic working on the valve was knowledgeable and able to answer all of the inspector's questions on how the valve operated. The inspector observed proper Quality Control oversight of this work activity. No discrepancies were noted.

6. Safety System Operability Verification (71710)

On a sample basis, the inspectors directly examined portions of selected safety system trains to verify that the systems were properly aligned in the standby mode. The following systems were examined:

6.1 Unit 1

a. Reactor Building Emergency Ventilation - this walkdown was conducted after the Unit 2 SBGT system decay heat removal mode was declared inoperable. The licensee was asked if, based on the Unit 2 design, there was a similar concern for the adequacy of the design at Unit 1. The licensee indicated that a review of the Unit 1 design had not been done. The licensee was asked to review the Unit 1 design and provide their conclusions to the inspector. This item will be reviewed in a subsequent report.

b. Core Spray

c. Containment Spray

d. Emergency Cooling

e. Emergency Power Supplies - diesel generators and station batteries

No violations were identified during these reviews.

6.2 Unit 2

a. Standby Gas Treatment

b. Emergency Diesel Generators Divisions I, II and III.

No violations were identified during these reviews.

7. Physical Security Review (71709)

The inspector made observations to verify that selected aspects of the station physical security program were in accordance with regulatory requirements, physical security plan and approved procedures.

The inspectors walked down the protected area perimeter and observed station access controls. No discrepancies were noted.

8. Radiological Protection Review (71881)

The inspector reviewed selected aspects of the licensee's radiological protection program to verify that the station policies and procedures were in compliance with regulatory requirements and that station employees were properly implementing the program.

No discrepancies were noted with the exception of the housekeeping observations previously stated in Section 4.1.b above.

9. Three Mile Island Action Plan Items (25565)

As a result of the Three Mile Island (TMI) plant accident, generic reactor enhancements were developed by the NRC. NUREG-0737 documents the specific action requirements. The following TMI issues were reviewed during this inspection period:

9.1 Unit 2

(Closed) (50-410/86-29-05): Primary Coolant Outside Containment - Action Item III.D.1.1. This item requires that the licensee implement a program to reduce leakage from systems outside containment which could or would contain highly radioactive fluids during a severe transient or accident. The licensee's January 16, 1986 submittal outlines their leakage control program. This program was found to be acceptable as documented in Supplemental Safety Evaluation Report (SSER) 3, Section 15.9.4.

In order to fully meet the requirements of Item III.D.1.1, the licensee was required by their Low Power Operating License, Condition 2.C.(12) to submit initial leak rate test results to the NRC for review. These results were submitted by the licensee on January 12, 1987. The information provided was reviewed in SSER 6, Section 15.9.4 and was found to be acceptable. Bases on the reviews of the licensee program, the initial leak rate information and system walkdowns this Action Plan Item is closed.

10. Allegation Followup (71707)

During the inspection period, the inspectors conducted interviews and inspections in response to an allegation presented to the licensee and NRC. The inspector and licensee actions resulting from this allegation are noted below:

10.1 Unit 2

Allegation No. RI-A-88-65: By copy of a letter dated June 2, 1988, from R.W. Golden, NYS, to G. J. Lavine, NMPC, the State of New York Department of Law, Assistant Attorney General informed the NRC Region I Administrator of an alleged incident at Unit 2 involving a violation of federal safety standards. The alleged violation of Occupational Safety and Health Administration (OSHA) Standard 1910.36(b)(4) involves an incident that occurred on September 14, 1987, involving the inadvertant locking of station workers in the steam tunnel airlock access without immediate means of egress.

Preliminary review of this incident by the inspectors indicates that an incident did occur and similar events may have happened on other occasions. The inspectors also verified with station management that appropriate interim compensatory action has been taken to prevent recurrence of this personnel safety concern until a viable hardware or design change can be made.

The State Attorney General's concern is being assigned an allegation number for tracking purposes. The inspector has requested that the licensee provide the NRC with a copy of their response to the June 2, 1988 letter for further review and followup.

11. Licensee Action on NRC Bulletins and Information Notices (92703)

The inspector reviewed licensee records pertaining to the NRC Bulletins and Notices identified below to verify that: the Bulletins and Notices were received and reviewed for applicability; written responses were provided, if required; and the corrective action taken was adequate.

Bulletin 88-05: Nonconforming materials supplied by Piping Supplies, Inc. and West Jersey Manufacturing Company. This bulletin was issued on May 6, 1988, and requires licensees to submit information regarding materials supplied by the above named companies and requests licensees to take actions necessary to assure that these materials comply with ASME Code and design specifications or replace such materials. The licensee's formal response has not been submitted (and is not due until September 1988); however, the inspector received some preliminary information from the licensee representatives responsible for followup of this bulletin.

Although the documentation review is not yet complete, the licensee has identified that materials were supplied by these companies. Parallel efforts are currently in progress to identify the specific applications of these components. The licensee anticipates approximately two months before a comprehensive list of items by location will be available. The inspector learned that licensee representatives attended the recently held NUMARC and EPRI owner's group workshops for resolution of Bulletin 88-05 concerns.

The inspectors will monitor licensee progress on this bulletin in subsequent inspections.

12. Assurance of Quality Summary (30702, 30703)

The control rod drive flange bolt inspections, the improper HPCS and RCIC condensate storage-to-supression pool suction swapover setpoint calculations and the multitude of fire barrier penetration seal problems are examples of ineffective control of contractors by the licensee.

The SBGT system decay heat removal issue was finally resolved when the NRC informed the licensee that the fire suppression water spray could be used as a short term alternate means of decay heat removal. The inspectors determined that station management had previously asked their Engineering and Licensing staffs if the fire suppression systems could be used as alternate decay heat removal methods and their response was that it could not. A supporting argument for its use and request for clarification was sought from the NRC staff. The licensee did have preliminary discussions with the resident inspectors to explore the

potential for enforcement discretion. This was discussed with licensee management for future reference.

Two events that occurred during this inspection period are examples of operator inattention to detail and lack of oversight by shift managers. The Unit 1 No. 12 service water pump in operation with a bearing temperature above the alarm setpoint should have been caught by the operators in the control room or the operators making rounds in the plant. The improper operation of the moisture separator low flow steam supply valves causing a pressure spike and a reactor scram is an example of an operator with good intentions, but with insufficient knowledge and/or oversight in performing a plant startup evolution. Conversely, the operator who detected the generator stator cooling coil leak is a good example of attentive and conscientious watchstanding.

13. Exit Meetings (30703)

At periodic intervals and at the conclusion of the inspection, meetings were held with senior station management to discuss the scope and findings of this inspection. Based on the NRC Region I review of this report and discussions held with licensee representatives, it was determined that this report does not contain Safeguards or 10 CFR 2.790 information.