U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket/Report Nos.:	50-220/96-06 50-410/96-06
License Nos.:	DPR-63 NPF-69
Licensee:	Niagara Mohawk Power Corporation P. O. Box 63 Lycoming, NY 13093
Facility:	Nine Mile Point, Units 1 and 2
Location:	Scriba, New York
Dates:	July 28 - September 7, 1996
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EXECUTIVE SUMMARY

Nine Mile Point Units 1 and 2
50-220/96-10 & 50-410/96-10
July 28 - September 7, 1996

This integrated inspection report includes reviews of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection.

PLANT OPERATIONS

During the Unit 1 shutdown of July 28, the inspectors noted difficulties with respect to the operator's ability to control reactor vessel water level, and confusion on the part of the Station Shift Supervisor (SSS) regarding the proper action when one control rod was at an indeterminate position. The SSS briefing for the shutdown was weak and did not include significant detail or a discussion of past problems.

Management oversight of the Unit 1 reactor startup on August 20 was good, and the pre-evolution brief by the Operations Manager was detailed and safety-focused. The control room staff demonstrated a questioning attitude and the briefing appeared synergistic. The presence of a Quality Assurance (QA) auditor and a Unit 2 senior reactor operator (SRO) in the control room during the startup was a positive attribute.

Unit 1 experienced two control rod drive (CRD) uncouplings during the period. The actions taken each time were appropriate. The decision to declare one of the CRDs inoperable due to recurring uncouplings, and the inability to verify coupling at the projected critical rod height during the planned startup was appropriate and conservative.

MAINTENANCE

The troubleshooting, repair, and post-maintenance testing activities associated with repetitive failures of a Unit 2 main steam line (MSL) radiation monitor were methodical, thorough, and appropriate. However, removal of the LCO required trips to conduct post-maintenance testing, prior to declaring the MSL radiation monitor operable, appears to be a violation of TS. NMPC disagrees with this position and submitted a letter to the NRC Office of NRR for clarification of the requirements. In addition, the need to remove LCO required trips to complete the testing to determine operability is not limited to the MSL radiation monitors at Unit 2, and may be generic to other plant systems. **(URI 96-01-01)**

The Unit 1 shaft-driven feedwater pump friction clutch failed to engage during a power ascension. Following repairs and post-maintenance testing, the system was improperly restored because of personnel error. This resulted in the clutch trying to engage while the output shaft was secured with a maintenance pin, causing damage to the clutch mechanism. When personnel removed the pin, the shaft started to rotate, which could have caused serious personal injury. Not withstanding the near miss, the technical meetings were thorough and safety-focused. Plant management was actively involved with numerous technical and operational concerns. The final repairs appeared appropriate and technically sound.

Unit 2 started a shutdown because both divisions of the control building chilled water system were inoperable due to low service water flow through the chillers. NMPC's determination of the low setpoint for the service water flow trip was inadequate design. (URI 96-10-02) The work orders were technically correct and the adjustments were performed correctly and without incident.

The NMPC procedure for procedure changes was inconsistent with the requirements of the Unit 2 TSs, which require two members of the unit management staff to approve the change, at least one of whom holds an SRO license. The procedure allowed approval by a "procedure owner" if the change was considered editorial. One of the possible editorial corrections allowed was one-for-one changes to existing information, if the change was supported by the reviews and approvals for the design document. This is a violation of TS 6.8.3 **(VIO 96-10-03)**. A strong procedure review and approval process should have identified this. This is the second example in less than a year where the NRC identified a programmatic procedure that departs from the requirements of the license. The other example was implementation of temporary modifications prior to completion of the required safety evaluations.

Three maintenance related issues were associated with poor personnel performance. A Unit 1 operator pulled the wrong fuses during application of a markup, resulting in the inadvertent scram of a control rod; a Unit 1 operator made a calculational error during completion of a core spray topping pump surveillance, resulting in a six week delay in identifying that the pump differential pressure was higher than the acceptance criteria; and a Unit 2 Instrumentation and Controls (I&C) Supervisor incorrectly changed a work order, resulting in maintenance on the wrong division of the hydrogen/oxygen (H_2/O_2) monitoring system. In each case, the procedures were not properly implemented. **(VIO 96-10-04)**

ENGINEERING

On August 28, 1996, Unit 2 operators entered the EOPs due to a positive pressure in the reactor building. During a surveillance on the standby gas treatment system, including the emergency recirculation ventilation subsystem, the test damper closed and the normal inlet damper opened. This placed the recirculation system in parallel operation with the normal ventilation exhaust fan; thus, less air was available for removal by the normal ventilation fan. An interlock caused the inlet damper to open if the test damper closed while the system was running. The operators responded appropriately to the transient, and the operability determination was adequate for normal operations; however, the adequacy of the surveillance procedure, with regards to the potential for a failure of the test damper to result in a challenge to secondary containment integrity, is unresolved. **(URI 96-10-05)**

General Electric (GE) informed NMPC that the cycle specific safety limit minimum critical power ratio (SLMCPR) for both units may be more limiting than previously determined for generic calculations. Both units implemented administrative limits until the completion of the GE cycle specific analysis. After receipt of the GE analysis, both units updated the core monitoring computer to reflect the change in the SLMCPR.

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REPORT DETAILS

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SUMMARY OF ACTIVITIES

Niagara Mohawk Power Corporation (NMPC) Activities

Unit 1

During this inspection period, Nine Mile Point Unit 1 (Unit 1) operated at varying reactor power levels due to mechanical difficulties with the #13 shaft-driven feedwater pump. On July 29, Unit 1 was shutdown to evaluate and repair the #13 feedwater pump clutch mechanism; additional activities during the outage included a drywell entry to repack a main steam isolation valve and repair an inoperable safety relief valve acoustic monitor and thermocouple. On August 3, Unit 1 was restarted, but reactor power was limited to approximately 46% because the repairs to #13 feedwater pump were unsuccessful. Unit 1 was again shutdown on August 8 to repair #13 feedwater pump, and investigation identified damaged dental clutch gear teeth. Unit 1 was restarted on August 11, but reactor power was still limited to 46% while an engineering evaluation determined a course of action for repair of the #13 feedwater pump. On August 17, Unit 1 was shutdown, #13 feedwater pump was repaired successfully, and the unit was restarted on August 21, achieving full power on August 23. Unit 1 operated at essentially 100% reactor power for the remainder of the period.

Unit 2

Nine Mile Point Unit 2 (Unit 2) maintained essentially 100% power throughout the period, with a short reduction to 85% power on August 14 due to maintenance on the control building chilled water system.

Nuclear Regulatory Commission (NRC) Staff Activities

Inspection Activities

The NRC resident inspectors performed inspections of the licensee's activities in the areas of operations, maintenance and surveillance, engineering, and plant support. The inspectors conducted their inspections during normal, backshift, and weekend hours. There were no specialist inspections conducted during this period. The results of the inspection are contained in this report.

Updated Final Safety Analysis Report (UFSAR) Reviews

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for additional verification that licensees were complying with UFSAR commitments. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the

UFSAR related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters, with the following exception. The description of the Unit 2 emergency ventilation system does not discuss the interlock associated with the unit cooler test damper (see Section E2.1).

I. OPERATIONS

O1 Conduct of Operations (71707) [1]

O1.1 General Comments

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety-conscious; specific events and noteworthy observations are detailed in the sections below.

O1.2 Unit 1 Shutdown to Repair the Shaft Driven Feedwater Pump

a. Inspection Scope

On July 28, 1996, Unit 1 was shutdown to repair the #13 shaft driven feedwater pump. The inspectors reviewed plant procedures prior to the scheduled shutdown (N1-OP-43A, "Reactivity Control," and N1-OP-43B, "Balance of Plant Startup and Shutdown"), attended the pre-evolution briefing held by the Station Shift Supervisor (SSS), and observed portions of the shutdown.

b. Observations and Findings

On July 28, 1996, the inspectors monitored Unit 1 control room operations associated with the normal plant shutdown to repair the shaft driven feedwater pump. Initial reactor power level was approximately 45%. Plant staff verified shutdown prerequisites and established the desired rod configuration. The power reduction and securing of the main turbine occurred without incident. The reactor was manually scrammed at low power to complete the reactor shutdown.

The inspectors noted that the operators had difficulty maintaining reactor vessel water level with the normal band. Initially, as a result of the scram, reactor vessel water level lowered from a normal level of 76 inches to approximately 38 inches. High pressure coolant injection (HPCI) initiated at 53 inches, as expected. By design, HPCI is supposed to secure at 95 inches to automatically maintain reactor level within a pre-established band. However, due to leakage past the feedwater

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[1] **Topical headings such as O1, M8, etc., are used in accordance with the NRC standardized reactor inspection report outline. Individual reports are not expected to address all outline topics. The NRC inspection manual procedure or temporary instruction that was used as inspection guidance is listed for each applicable report section.**

regulating valves, and excessive flow from the control rod drive (CRD) system, reactor vessel level continued to rise above the top of the narrow range level instrumentation.

The operators verified that the reactor was shutdown. All control rods indicated fully inserted, except one. The numeric rod position indication (RPI) for control rod 14-47 did not indicate, the green "full-in" lights for the rod on the full-core display were not lit, and the process computer identified the rod position as full out. The confusion over the position of control rod 14-47 delayed resetting of the scram for nearly one hour. This delay exacerbated the problem with the rising reactor vessel water level, as full CRD flow continued until the scram was reset. The SSS discussed the problem with the Operations Manager and concluded that procedure N1-OP-43A allowed the scram to be reset to verity that all control rods were inserted. The scram was reset and control rod 14-47 indicated fully inserted. Subsequently, a procedure change was processed to make it consistent with the associated emergency operating procedure (EOP), N1-EOP-3.1, Rev. 1, which required the scram to be reset to allow for alternate control rod movement in the event a rod was stuck.

The inspectors observed the SSS's pre-evolution brief, which broadly reviewed the upcoming shutdown and outage work scope. But the inspectors noted that there was little interaction between the SSS and the operating crew relative to potential problems or past difficulties; such as previous problems with the rod position indication on shutdowns. Additionally, delineation of responsibilities and overall coordination techniques were not discussed among the crew. This lack of communication and forethought may have contributed to the problems that the crew experienced with reactor level, or the confusion as to the proper action when one control rod was at an unknown position. The inspectors discussed the shutdown with the SSS, who concurred that the shutdown did not go smoothly. The SSS stated that the crew had not performed a shutdown recently, and that training in the simulator would have been beneficial in reviewing plant response and clarifying operator roles and responsibilities.

On August 17, the loss of RPI for the same control rod recurred during a subsequent shutdown with a scram from $\approx$5% power. During this scram, the full-core display again failed to identify position for control rod 14-47; however, the process computer indicated the rod had inserted. When questioned by the inspectors, the system engineer indicated these losses of RPI were due to failures in the RPI system probe buffer card and the full-in over-travel reed switch. The buffer card was replaced, and the reed switch is scheduled for additional troubleshooting during the next extended outage.

c. <u>Conclusions</u>

The shutdown did not progress smoothly. Difficulties were noted with respect to controlling reactor vessel water level, and there was confusion regarding the proper action when one control rod was at an indeterminate position. The inspectors considered the SSS briefing weak, in that it did not include significant detail of the

planned shutdown nor a discussion of past problems. This may have caused some the problems noted by the inspectors.

O1.3 Unit 1 Startup

a. Inspection Scope

The inspectors observed control room operations during a plant startup on August 20, 1996. Specifically, the inspectors monitored part of the startup prerequisite verification, the initial reactor startup, power ascension, and post-maintenance testing of the shaft-driven feedwater pump.

b. Observations and Findings

During the reactor startup, the inspectors noted that operations management was present to observe the evolution. Prior to the special evolution (power ascension and testing of the shaft-driven feedwater pump), the Operations Manager conducted a Management Expectations Briefing with the crew in accordance with procedure GAP-SAT-03, "Control of Special Evolutions," Revision 02, Section 3.4.1. The discussion included management's expectations for conduct of operations, detailed hardware and operational changes pertaining to the #13 feedwater pump temporary modification, and addressed the upcoming schedule of events.

The startup was completed without incident. The inspectors noted that a quality assurance (QA) auditor monitored the power ascension and the post-maintenance testing of the #13 feedwater pump. Also, subsequent to criticality and prior to placing the unit online, Unit 1 operations management was present to observe the conduct of control room operations. Additionally, the inspectors noted that a Unit 2 senior reactor operator (SRO) monitored Unit 1 control room activities, as an independent observer, to identify weaknesses and ways to develop consistency between the units.

c. Conclusions

Management oversight of the reactor startup was good, and the pre-evolution brief was detailed and safety-focused. The control room staff demonstrated a questioning attitude and the briefing appeared synergistic. The presence of QA and a Unit 2 SRO in the control room during the startup was a positive attribute.

O2 Operational Status of Facilities and Equipment (71707)

O2.1 Unit 1 Control Rod Uncouplings

a. Inspection Scope

During this inspection period, the licensee identified two potential control rod drive (CRD) uncouplings at Unit 1. The inspectors discussed current and previous CRD uncouplings with plant management and staff; reviewed licensee Deviation/Event

Reports (DERs), including potential causes and proposed/completed corrective actions; and reviewed General Electric (GE) Service Information Letter (SIL) No. 052, Supplement 2 (dated July 31, 1974) and Supplement 3 (dated March 17, 1989) relating to CRD anomalies.

b. Observations and Findings

On July 31, 1996, CRD 46-27 was being continuously withdrawn as part of startup prerequisites. The plant was shutdown with the mode switch in REFUEL. During the rod withdrawal, the over-travel annunciator alarmed, indicating that the rod was potentially uncoupled. The rod was fully inserted and probably recoupled. During a subsequent withdrawal, the rod again indicated uncoupled. The Operations Manager was concerned that the estimated position for CRD 46-27 during the upcoming startup would be approximately 12 inches, and uncoupling checks could not be performed at this rod height. Therefore, plant management decided, after discussion with reactor engineering personnel, to fully insert the rod, declare the rod inoperable, valve it out of service, and perform repairs during the upcoming refueling outage (RFO14) in Spring 1997.

On August 6, 1996, a second CRD (# 18-35) indicated that it was uncoupled during the weekly uncoupling checks. The rod was inserted and verified recoupled, and returned to the previous position, in accordance with Procedure N1-OP-5.

NMPC stated that CRD uncouplings were uncommon at Unit 1; however, in 1991/1992, five CRD uncouplings occurred during that fuel cycle period. NMPC documented the uncouplings on four DERs. Four of the five CRD units were replaced during the next refueling outage, and the other CRD unit was replaced during a later forced outage. Since 1992, no other CRD uncouplings were documented.

Of the five 1991/1992 CRD uncouplings, one resulted from separation of the inner filter from the stop piston. During rod withdrawal, the inner filter impacted against the uncoupling rod with sufficient force to uncouple the drive from the rod. Inner filter separation could be attributable to either improper inner filter installation or distortion/wear of the inner filter latching spring. A second uncoupling was attributed to a bent uncoupling rod in the center spud hole; NMPC assumed the most probable cause was that the uncoupling rod was reversed in the spud base, permitting the uncoupling rod to move within the spud. The root causes of the remaining three CRD uncouplings were not positively determined.

The inspectors' review of GE SIL 52 identified that all CRD uncoupling problems were attributed to internal drive problems. The probable causes were: 1) improper installation and engagement of the inner filter; 2) improper positioning of the control rod lock plug due to binding of the lock plug shaft or uncoupling D-handle; 3) crud buildup on the inner filter; or 4) the wrong uncoupling rod or mispositioning of the uncoupling rod. GE also determined that if a drive uncoupled and was subsequently recoupled, the drive was considered operable; however, motion should be restricted

to jog only mode of withdrawal operation and the drive should be removed for filter screen inspection and replacement during the next scheduled outage.

Although CRD uncoupling was not a common industry occurrence, NMPC documented their evaluation of the GE SIL against the potential for this to occur at Unit 1. From an accident perspective, an uncoupled rod could result in a positive reactivity excursion due to a dropped rod, which is an analyzed condition. The inspectors did not identify any safety concerns.

c. Conclusions

NMPC's decision to declare CRD 46-27 inoperable due to recurring uncouplings and the inability to verify coupling at the projected critical rod height appeared appropriate and conservative.

O2.2 Unit 2 RCIC Walkdown

The inspectors walked down the accessible portions of the Unit 2 reactor core isolation cooling (RCIC) system, and reviewed the recently completed surveillance tests for the system (N2-OSP-ICS-001) to verify operability. The material condition of the components and the general housekeeping were acceptable, with the exception of a minor packing leak on the steam trap bypass valve. NMPC was aware of the steam leak, had scheduled it for repair, and completed the repairs subsequent to the end of the reporting period.

O8 Miscellaneous Operations Issues (90712, 92700, 92910)

O8.1 (Closed) Unit 1 Special Report: #12 Drywell High Range Gamma Radiation Monitoring System Inoperable

On March 25, 1996, with Unit 1 operating at 100% reactor power, NMPC declared the #12 drywell high range gamma radiation monitoring system inoperable to replace a resistor. During the period when #12 drywell high range gamma radiation monitoring system was out of service, the redundant system was operable. Repairs were completed on March 26, and NMPC returned the system to service following post-maintenance calibration.

NMPC submitted a special report to the NRC within 14 days, as required by Unit 1 Technical Specifications (TS) 3.6.11-1, Action Statement Table 3.6.11-2 (3a). The inspectors reviewed the special report and confirmed that all required information was provided.

O8.2 (Closed) Unit 1 Special Report: #12 Drywell High Range Gamma Radiation Monitoring System Inoperable

On August 11, 1996, with Unit 1 reactor mode switch in STARTUP, NMPC removed the #12 drywell high range gamma radiation monitoring system from service due to a downscale indication. Instrument and control (I&C) technicians checked the

calibration of the system and found no out-of-tolerance condition. The I&C technicians also performed a wire integrity check and source check, but noted no abnormalities. During the period when #12 drywell high range gamma radiation monitoring system was out of service, the redundant system was operable. NMPC declared the system operable on August 13, after calibration and a 24-hour period of monitoring.

NMPC submitted a special report to the NRC within 14 days, as required by Unit 1 TS 3.6.11-1, Action Statement Table 3.6.11-2 (3a). The inspectors reviewed the special report and confirmed that all required information was provided.

O8.3 <u>(Closed) VIO 50-220/95-03-01: Operator Actions Contrary to Procedures</u>

In April 1995, Unit 1 experienced a reactor scram due to a turbine trip. During the post-scram review, NMPC identified two cases where procedures were not properly implemented:

- During the immediate actions following the scram, the Chief Shift Operator (CSO - a licensed reactor operator) failed to properly position the reactor mode switch.
- After the scram, during troubleshooting to determine why Power Board #11 failed to automatically transfer to the reserve power supply, it was determined that an operator had not performed an electrical continuity check of the fast transfer control circuitry after the turbine generator was paralleled to the grid on the previous startup.

NMPC attributed the cause of both of the above instances to operators not self-verifying correct completion of all necessary actions after the conclusion of the activity. In addition, the SSS failed to ensure that personnel on his shift had referred to the appropriate procedures to verify implementation, as written. The corrective actions included a reinforcement of specific procedural requirements and NMPC's expectations regarding the use and adherence to procedures and self-checking. The inspectors considered the corrective actions acceptable.

O8.4 <u>(Closed) URI 50-220/95-03-02: Procedures not Consistent with Technical Specifications</u>

During a review of the reactor scram in April 1995 (discussed in Section O8.3), the inspectors considered certain procedures were not consistent with Unit 1 TSs. Specifically, the scram procedure (N1-SOP-01, "Reactor Scram") and the EOP for an anticipated transient without a scram (NMP1-EOP-3, "Failure to Scram") allowed the reactor mode switch to be left in the REFUEL position. When in the hot shutdown condition, the Unit 1 TS required the mode switch to be in the SHUTDOWN position except for scram recovery operations. As a result of discussions with the NRC inspectors, NMPC initiated DER 1-95-1241.

NMPC determined that the procedures were acceptable, as written, but that the implementation needed clarification. By placing the mode switch in the REFUEL

position, the operators are able to manipulate control rods, as necessary, to insert any control rods that did not settle at position "00" on the scram; if no rod movement was being attempted, the mode switch was to be in the SHUTDOWN position. The associated procedures were changed to reflect the clarifications discussed above; i.e., maintaining the mode switch in REFUEL while in the hot shutdown condition for reasons other than scram recovery, is not permitted. The inspectors considered the corrective actions acceptable.

O8.5 (Closed) URI 50-220/95-16-01: Weak Initial Operability Determinations

In September 1995, based on discussions with the SSS and a review of the SSS log, the NRC identified two instances where initial operability determinations by shift supervision were considered weak. NMPC initiated a review of the specific instances and determined that the SSS had performed an appropriate operability determination, but had not clearly documented the basis for the determination in the SSS log. The inspectors reviewed the associated DER and the specific final operability determination and discussed the concern with NMPC operations management. The inspectors have since observed that the bases for operability determinations are better documented. The inspectors had no further questions regarding this item.

II. MAINTENANCE [2]

M1 Conduct of Maintenance (61726, 62703, 62707)

Using Inspection Procedures 61726, 62703, and 62707, the inspectors periodically observed plant maintenance activities and performance of various surveillance tests. In general, maintenance and surveillance activities were conducted professionally, with the work orders (WOs) and necessary procedures at the work site and in use, and with the appropriate focus on safety. Specific activities and noteworthy observations are detailed in the sections below. The inspectors reviewed procedures and observed portions of the following maintenance/surveillance activities:

- WO 96-10638-00 — Troubleshooting of Division II H_2/O_2 Monitor
- N2-ISP-MSS-R109 — Main Steam Line High Radiation Monitors Instrument Channel Calibration
- N2-OSP-CSL-R@002 — Hydrostatic Leakrate Test for 2CSL*MOV112
- WO 96-11219-01 — Lower Setpoint for Condensing Water on Chiller 2HVK*CHL-1A
- WO 96-11219-02 — Lower Setpoint for Condensing Water on Chiller 2HVK*CHL-1B

[2] Surveillance activities are included under "Maintenance." For example, a section involving surveillance observations might be included as a separate sub-topic under M1, "Conduct of Maintenance."

• N2-IPM-SWP-R109	Calibration of the Control Building Service Water Flow Instrument Channels
• N2-OPS-GTS-M001	Standby Gas Treatment System Functional Test
• N1-ST-Q1B	Core Spray Loop 12 Pumps and Valves Operability
• GAP-OPS-02	Control of Hazardous Energy and Configuration Tagging
• GAP-PSH-01	Work Control
• NIP-PRO-04	Procedure Change Evaluations

M1.1 Unit 2 Main Steam Line Radiation Monitor Failures

a. Inspection Scope

The inspectors reviewed the troubleshooting, repair, and post-maintenance testing activities associated with repetitive failures of the Unit 2 main steam line (MSL) radiation monitor on August 29, and September 3, 1996. The inspectors also reviewed the applicable TS sections, and discussed the method used by NMPC to declared the system operable following the corrective maintenance.

b. Observations and Findings

On August 29, during a walkdown of the control room main control panels, the oncoming Assistant Station Shift Supervisor (ASSS) observed that the "B" MSL radiation monitor (2MSS*RT46B) was reading abnormally high. A review of the three previous shift checks identified that the indications were normal. The radiation monitor was declared inoperable and TS 3.3.1 was entered. The TS action statement requires placing the inoperable channel in a tripped condition within 12 hours. This causes a ½ trip signal for the nuclear steam supply shutoff system (NSSSS) and a ½ reactor protection system (RPS) scram. DER 2-96-2054 was written to address the failure concurrent with initiation of repair activities.

Troubleshooting identified that the detector was working properly but that the monitor control panel drawer had a problem. NMPC replaced the suspect drawer with a functioning spare drawer. Subsequent investigation identified a bad module in the drawer.

The troubleshooting and repairs took longer than twelve hours to complete. Thus, NMPC took the required actions and inserted the channel trips, as required by the TS limiting condition for operation (LCO). On August 30, the routine calibration (N2-ISP-MSS-R109, "Main Steam Line High Radiation Monitors Instrument Channel Calibration," Revision 1) was being used for post-maintenance testing to determine the radiation monitor operability.

During the post-maintenance testing on August 30, the inspectors observed that the LCO required trips were cleared in support of testing. The inspectors questioned shift management regarding removal of the trips while the LCO action statement was still in effect. The SSS informed the inspectors that the trips had to be cleared to perform the surveillance test before the channel could be declared operable. Additionally, the SSS stated that this had been discussed with operations

management; and referred to the basis section associated with TS 4.0.3, which states that surveillance requirements have to be met to demonstrate that inoperable equipment has been restored to operable status.

Not withstanding the above justification, the removal of the LCO-required trips prior to declaring the MSL radiation monitor operable appears to be a violation of TS 3.3.1. NMPC disagrees with this interpretation of the TS and, subsequent to the inspection period, issued a letter to the NRC (dated October 21, 1996), requesting a clarification of a "... longstanding [industry] position that permits the conduct of certain technical specification surveillance and testing needed to demonstrate that previously inoperable equipment has been restored to an operable condition." Pending an evaluation of this issue by the NRC Office of Reactor Regulation (NRR), and a review of the NRR response to NMPC, this item will remain unresolved. **(URI 50-410/96-10-01)**

On September 3, operators again observed that radiation monitor 2MSS*RT46B was spiking from 650 mrem/hour to 1450 mrem/hour. The radiation monitor was declared inoperable and troubleshooting identified a bad connector between the drawer and the detector. The connector degradation was apparently due to heat, but manipulation of the cable and connector during the August 30th troubleshooting and testing may have contributed to connector failure.

Although NMPC has had no indication of problems with the other three channels of MSL radiation monitoring, they checked the local temperatures for all of the MSL radiation monitor connectors and found them within vendor recommendations. NMPC also intended to examine the remaining connectors during the upcoming refueling outage. The inspectors considered this action to be appropriate.

NMPC replaced the connector for MSL radiation monitor 2MSS*RT46B and was able to determine operability of the affected portions of the radiation monitor without removing the LCO required trips. The inspectors, through discussions with the work supervisor, and review of the repairs and plant drawings, verified that the post-maintenance testing was adequate.

c. <u>Conclusions</u>

Troubleshooting activities for both MSL radiation monitor failures were methodical and thorough. The examination by NMPC for similar connector degradation was considered appropriate. However, removal of the LCO required trips, prior to declaring the MSL radiation monitor operable, appeared to be a violation of TS; furthermore, the need to remove LCO required trips to complete the testing to determine operability is not limited to the MSL radiation monitors. This item is unresolved pending further NRC review.

M1.2 Unit 2 LPCS Pump Suction Valve Leak Rate Testing

a. Inspection Scope

On August 27, 1996, leak rate testing on the Unit 2 low pressure core spray (LPCS) pump suction valve failed due to the inability to achieve rated test pressure; subsequent testing was successful. The inspectors observed portions of the retest, reviewed the test procedure, and discussed the test with NMPC staff.

b. Observations and Findings

During performance of procedure N2-OSP-CSL-R@002, "Hydrostatic Leakrate Test for 2CSL*MOV112," Revision 2, Unit 2 operators were unable to reach the required test pressure of 50-52 pounds per square inch gage (psig). While trying to pressurize the space between motor operated valve (2CSL*MOV112) and the manual isolation valve (2CSL*V121), the operators injected approximately 30 gallons of water and only raised pressure from 5 psig to 17 psig. The test was considered unsatisfactory and appropriate actions were taken in accordance with TS for an inoperable containment isolation valve. Additionally, a DER was written to address the test failure.

Based on previous successful leak rate testing of MOV112, and other MOVs in similar plant configurations, NMPC evaluated the test failure and believed that the manual isolation valve was not completely closed, possibly due to foreign material on the valve seat. NMPC cycled open and closed 2CSL*V121, under the appropriate administrative controls, satisfactorily retested MOV112 without any adjustments to the valve, and exited the LCO.

The inspectors reviewed the initial test procedure which was completed unsatisfactorily, and discussed the cause of the test failure with the system engineer. Based on the discussion and a review of the DER disposition, the inspectors considered the cause reasonable.

c. Conclusions

The inspectors considered the analysis to determine the cause of the LPCS pump suction valve surveillance failure to be good. Subsequent retest of the valve was successful and timely.

M2 Maintenance and Material Condition of Facilities and Equipment (61726, 62703)

M2.1 Repairs to Unit 1 Shaft Driven Feedwater Pump

a. Inspection Scope

The friction clutch for the Unit 1 #13 shaft-driven feedwater pump failed to engage during a power ascension on July 22, 1996. The inspectors reviewed the associated troubleshooting, evaluation, and repair activities; discussed the course of

action with plant staff and management; attended review meetings, and reviewed applicable DERs, design document changes, temporary modifications, and applicability reviews.

b. Observations and Findings

On July 19, 1996, the #13 shaft-driven feedwater pump was secured as part of a scheduled power reduction to inspect and clean the main turbine condenser water boxes. On July 21, while attempting to engage the feedwater pump friction clutch prior to increasing power, the clutch failed to adequately engage, resulting in the inability to achieve required speed. The licensee determined that failure of the friction clutch to engage was due to internal binding of an associated solenoid operated valve (SOV-29-01 V1A/B), which resulted in insufficient oil pressure to the friction clutch. A representative from the vendor, Philadelphia Gear, noted discoloration of the valve internals, presumed to be a result of lubricating oil breakdown, and concluded that the SOV failed from age-related wear. The SOV was replaced, and two additional SOVs used under similar operational conditions, were identified and replaced. DER 1-96-1696 was written to identify these deficiencies.

On July 22, following repairs on the shaft-driven feedwater pump, NMPC personnel cleared the markup to conduct post-maintenance testing. However, the SOV was left in the "engaged" position; and when control power and actuating oil pressure were restored as part of the markup clearance, the friction clutch tried to engage the output shaft which was locked in position with the maintenance pin. The pin is designed to prohibit movement of the feed pump output shaft. This resulted in damage to the clutch mechanism. When plant personnel removed the pin, the shaft started to rotate. This could have resulted in serious personal injury and was considered a "near-miss" by NMPC. The licensee issued DER 1-96-1718 to address this issue and determine the root cause. Unit 1 was shutdown on July 28 to perform repairs. Plant management conducted "tail-gate" training with all maintenance and operations personnel relative to the personnel errors described above. The training included a discussion of what happened, how the activity should have been performed, and the potential consequences.

Unit 1 was restarted on August 3, with reactor power limited to approximately 46% because of the inoperable shaft-driven feedwater pump. On August 7, during startup of the #13 pump, the dental clutch failed to properly engage. On August 8, NMPC took the unit off-line. NMPC identified two possible reasons for why the dental clutch did not engage: (1) a gasket was missing on a control oil supply line spectacle flange, and (2) the constant bleed ports for the friction clutch had been clogged, but were cleaned and opened. The system engineer stated that the combination of the gasket and the constant bleed ports probably lowered the friction clutch actuating oil pressure, allowed slippage of the friction clutch, and caused dental clutch damage. The speed mismatch of the feedwater pump input and output shafts resulted in the damage to the dental clutch. The plant was again restarted on August 11, with the shaft-driven feedwater pump inoperable, and operated at approximately 46% rated thermal power until another

outage on August 17. NMPC was informed that repairs to the dental clutch would take about 15 weeks. After considering several options, NMPC elected to operate the pump solely on the friction clutch.

Unit 1 was restarted on August 22, post-maintenance testing was completed satisfactorily, and the unit returned to full power on August 23. The inspectors noted that NMPC's technical meetings were thorough and safety-focused, and the engineering applicability review per 10 CFR 50.59 was determined to be appropriate.

c. <u>Conclusions</u>

Failure to confirm the position of the SOV following maintenance, and poor coordination between the I&C technicians and operations personnel during clearing of the markup, resulted in friction clutch engagement with the maintenance pin installed. Also, plant personnel who removed the pin could have sustained serious personal injury.

The technical review meetings were thorough and safety-focused. Plant management raised numerous technical and operational concerns, that were subsequently resolved. Overall, the inspectors determined that the final repairs appeared appropriate and were technically sound. However, personnel inattention resulted in damage to the clutch mechanism, and could have resulted in a serious personal injury.

M2.2 <u>Unit 1 Control Rod Scram Solenoid Pilot Valve Diaphragm Replacement</u>

In the fall of 1995, industry concerns regarding slow scram insertion times were identified. Particularly, the 5% insertion times were found to be increasing for scram solenoid pilot valves (SSPVs) equipped with Viton diaphragms. At Nine Mile, only Unit 1 was affected, since Unit 2 SSPVs are of a different design. As documented in NRC Inspection Report 50-220/96-02, NMPC initiated periodic at-power scram time testing, as recommended by the Boiling Water Reactor Owner's Group's (BWROG's) Regulatory Response Group (RRG), to address the concern.

Since the concern was identified, NMPC had been replacing the Unit 1 Viton diaphragms with new Buna-N diaphragms. By August 11, 1996, all Unit 1 SSPV Viton diaphragms were replaced with the new material and tested satisfactorily. Subsequently, NMPC terminated the periodic at-power scram time testing at Unit 1. Since February 1996, the inspectors have periodically monitored the diaphragm replacements, discussed and observed NMPC's actions to resolve the concern with the Viton diaphragms, and noted no concerns.

M2.3 Unit 2 TS Required Shutdown due to Both Divisions of the Control Building Chilled Water System Inoperable

a. Inspection Scope

On August 13, 1996, the Unit 2 SSS initiated a plant shutdown because both divisions of the control building chilled water system were inoperable. The inspectors monitored portions of the shutdown and the maintenance activities to return the systems to service; this included a review of the maintenance and surveillance packages, the shutdown procedure, and the administrative procedures supporting the work.

b. Observations and Findings

When starting the Division 2 emergency diesel generator (EDG) for a planned surveillance test, the Division 2 control building chiller automatically tripped due to low service water flow. The chiller is part of the control building chilled water system, which is a subsystem of the control room outdoor air special filter train system. The special filter train system is an emergency system that ensures the control room and remote shutdown rooms are capable of being maintained habitable during post-accident modes of plant operation by diverting outside air through a charcoal filter. The chillers support the operation of the special filter train by cooling the outside air. In accordance with the Unit 2 TS 3.7.3, the Division 2 control building outdoor air special filter train system needed to be declared inoperable.

The chiller tripped at 10:26 a.m. on August 13, at which time the SSS declared the Division 2 chiller inoperable. With one division of the special filter train system inoperable, the TS LCO action statement allows 7 days for repairs or the plant must be shutdown. NMPC engineering determined that the trip setpoint for the low service water flow automatic action was set too high, and had been since June 1989, when the low trip setpoint was increased from 215 gallons per minute (gpm) to 250 gpm. It was determined that the Division 1 chiller was also affected, and the SSS declared that chiller inoperable at 5:11 p.m. With both divisions of the special filter train system inoperable, TS 3.7.3 is not applicable. TS 3.0.3 states that when an LCO cannot be met, place the plant in an operational condition where the TS does not apply. In this case, the plant was required to be shutdown within 12 hours.

Power reduction was started at 5:45 p.m. Coincident with shutdown activities, engineering reviewed the design of the service water system in conjunction with the anticipated demands on the system during accident conditions. They determined that the low flow setpoint could be adjusted from the current 250 gpm to 210 gpm. Maintenance work orders were initiated to adjust the trip setpoints (WO 96-11219-01 and WO 96-11219-02, Lower Setpoint for Condensing Water on Chillers 2HVK*CHL-1A and 2HVK*CHL-1B, respectively). The Division 1 chiller was declared operable after the flow setpoint had been adjusted and satisfactorily

tested. At 8:11 p.m., power reduction was stopped at 85% and Unit 2 exited TS 3.0.3. Power was returned to 100% the same day.

NMPC's preliminary determination of the cause for the low setpoint for the service water flow trip was inadequate design. Pending completion of the engineering evaluation by NMPC and NRC review, this item will remain unresolved. **(URI 50-410/96-10-02)**

The inspectors reviewed the work orders and monitored part of the trip setpoint adjustment. The work orders were technically correct and the adjustments were performed correctly and without incident. During the review of the change to the surveillance procedure for the calibration of the chiller service water flow instruments that was used for the post maintenance test, the inspectors identified that the procedure change evaluation (PCE) form was incorrectly completed. Specifically, the preparer of the PCE and the responsible procedure owner (RPO) were the same person. Per NMPC Procedure NIP-PRO-04, "Procedure Change Evaluations," Paragraph 3.3.1.a, the RPO must be an individual other than the preparer. Another qualified RPO reviewed and approved the PCE before work continued; and the original RPO generated a deviation/event report (DER 2-96-1906) to document the problem and initiate corrective actions to prevent recurrence. The failure to properly complete the PCE form is a violation of TS 6.8.1. Based on the immediate corrective actions and low safety consequence, this NRC identified violation is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy.

c. Conclusion

The SSS recognized the effect of the chiller tripping during the test of the EDG and took the appropriate actions related to one inoperable division of the control building outdoor air special filter system. When the second division was also deemed inoperable, the actions required by TS 3.0.3 were initiated coincident with adjustments to the flow switches. NMPC's preliminary determination of the cause for the service water flow trip low setpoint was inadequate design.

M3 Maintenance Procedures and Documentation (61726, 62703, 62707)

M3.1 Procedure Changes Not in Accordance with TS Requirements

a. Inspection Scope

During the review of the procedure change evaluation (PCE) forms associated with the repairs of the control building chillers discussed in Section M2.3 of this report, the inspectors noted that the procedure was not consistent with the requirements of Unit 2 TSs.

b. Observations and Findings

TS 6.8.3 requires temporary changes to procedures be approved by two members of the unit management staff, at least one of whom holds an SRO license on the affected unit. NIP-PRO-04, "Procedure Change Evaluations," paragraph 3.3.3.c, does not require an SRO approval; only an RPO approval is needed for editorial corrections.

NMPC site-common procedure NIP-PRO-04 has defined a type of procedure change called an "editorial correction." Editorial corrections included enhancing existing information already in the procedure that was not technical, correcting obvious non-technical errors to existing information, updating reference numbers to other documents or correcting misspellings, and other administrative type of correction. This practice is not uncommon in the nuclear industry. However, NIP-PRO-04 also allowed design changes to be considered as "editorial corrections." Editorial correction Criterion 3, allowed one-for-one changes to existing information to incorporate changes to controlled design documents. The changes needed to be entirely supported by the reviews and approvals for the design document. The design document shall be referenced on the PCE and may include EDC [Engineering Design Change]/DCRs [Document Change Requests], specifications, or approved calculations (such as setpoints by EDCs).

To revise the chiller service water low flow setpoint, a PCE was generated for surveillance Procedure N2-IPM-SWP-R109, "Calibration of the Control Building Service Water Flow Instrument Channels." The PCE was classified as an editorial correction, with RPO approval only. A change to the acceptance criteria should be considered a technical change, and SRO approval is required. The failure to obtain SRO approval of the temporary change prior to implementation is a violation of Unit 2 TS 6.8.3. **(VIO 50-410/96-10-03)**

c. Conclusion

A shrong procedure review and approval process should have identified that the PCE procedure was not consistent with the requirements of the Technical Specifications. This is another example where the NRC has recently identified a programmatic procedure that departs from the requirements of the license. A past example was discussed in NRC Inspection Report 96-01, and related to the implementation of temporary modifications prior to the completion of the required safety evaluations.

M4 Maintenance Staff Knowledge and Performance (61726, 62703, 62707)

M4.1 Personnel Performance

The inspectors reviewed the below three maintenance-related issues, all associated with personnel performance errors. The review included applicable portions of the SSS and CSO logs, plant procedures, Licensee Event Reports (LERs), DERs, the

UFSARs and TSs. Also, the inspectors held discussions with plant personnel and management regarding these events.

- Unit 1 - inadvertent scram of the wrong control rod;
- Unit 1 - calculation error not identified during core spray surveillance; and
- Unit 2 - maintenance on the wrong division of H_2/O_2 monitoring.

The details associated with these issues are provided in the following three sections, with an overall conclusion provided in Section M4.5 of this report.

M4.2 Unit 1 Inadvertent Scram of a Single Control Rod

On July 26, 1996, with Unit 1 operating at approximately 45% power, control rod 18-31 had been fully inserted and removed from service to support maintenance activities on the associated hydraulic control unit (HCU). During the application of the markup for HCU 18-31, the operator applying the markup removed the fuses for the wrong control rod (38-31), causing rod 38-31 to scram from the fully withdrawn position. (A markup is a component tagging process used to provide protection for personnel and/or equipment during operation, maintenance and modification activities. Within the industry, this is commonly referred to as a tagout.) The control room operators identified the error, instructed the operator to replace the fuses for control rod 38-31, and complete the markup of HCU 18-31. The SSS conferred with Reactor engineering, and control rod 38-31 was restored to the fully withdrawn position.

NMPC reactor engineering informed the inspectors that the impact of the inadvertent rod scram on the plant was minimal, due to the low power level at the time of the event. The inspectors considered NMPC's immediate actions to recover from the event to be appropriate.

As noted on the associated DER, the apparent cause was that the operator failed to verify the correct component prior to removing the fuses. NMPC also determined that a contributing factor was the operator's self-imposed schedular pressure to prepare for shift turnover.

As a result of this event, the individual involved was counseled and Unit 1 operations management generated a night order to emphasize their expectation of concurrent verification during the application of markups associated with HCU maintenance. Concurrent verification was defined as a second checker positively identifying the correct component and intended action before any actions are taken. NMPC's expectation regarding the use of concurrent verification was already provided in the Unit 1 Operations Reference Manual. Through discussions with Unit 1 personnel, the inspectors ascertained that prior to this event, HCU markups were completed using independent verification and not the more conservative concurrent verification. Until recently, HCU maintenance was not routinely completed at power. The inspectors considered these corrective actions appropriate to address this particular event.

The inspectors reviewed Procedure GAP-OPS-02, "Control of Hazardous Energy and Configuration Tagging," Revision 6, which required the operator applying the markup to place all necessary devices in the required position and then apply the completed tag. The failure to remove the correct fuses, as per the markup order, is considered an example of a procedural violation. The violation is described in Section M4.5 of this report.

M4.3 Calculation Error During Unit 1 Core Spray Surveillance

On July 17, 1996, Unit 1 plant management determined that the unit had been operated in a condition prohibited by TS since June 6, 1996. Specifically, a calculational error, during the performance of surveillance test procedure N1-ST-Q1B, "Core Spray Loop 12 Pumps and Valves Operability," was identified for core spray topping pump 121 (CSTP-121) differential pressure (dp). The surveillance test involved throttling core spray system flow to meet prescribed procedural guidance values and obtain flow data. The control room operators used this data to perform additional calculations to determine pump differential pressure.

The operator who performed the initial calculations omitted a pressure correction factor for gauge elevation. During the same shift, the ASSS discovered the error and corrected a portion of the calculation, the result of which was to be carried forward to subsequent steps. However, the ASSS failed to carry the corrections through the remainder of the calculations. The following day, the inservice testing (IST) supervisor also failed to identify the error during his review. The error was finally discovered six weeks later, July 17, during a final supervisory review. When the error was discovered, the licensee determined that the pump dp was higher than the acceptance criteria. Although the pump remained available, the pump was declared inoperable because the dp was outside of the acceptable range and, therefore, the surveillance test was unsatisfactory. A differential pressure higher than expected is normally considered good. However, since this was an IST examination, the acceptable range is determined by the pump curves defined by the American Society of Mechanical Engineers (ASME) manual. The surveillance was reperformed on July 17, the dp was acceptable, and CSTP-121 was declared operable.

The licensee's root cause was cognitive personnel error due to inadequate self-checking of calculations; also, the failure of more than one individual to identify the error is significant. The calculation error in performance of surveillance test N1-ST-Q1B, and the failure to perform adequate supervisory reviews, are additional examples of procedural violations. The violation is described in Section M4.5 of this report.

Subsequently, NMPC issued LER 50-220/96-06, describing this event. The review of the LER is contained in Section M8.2 of this report.

M4.4 Unit 2 Maintenance Activities on the Incorrect Division of H_2O_2 Monitoring

On July 25, 1996, while Unit 2 was operating at 100% reactor power, I&C technicians performed troubleshooting on the wrong division of the hydrogen/oxygen (H_2/O_2) monitoring system. At the time of the event, the Division 2 H_2/O_2 monitor was inoperable due to the indicated H_2 concentration (1.6%) being inconsistent with actual chemistry samples (0%). During troubleshooting activities performed under WO 96-10638-00, technicians lifted leads for the Division 1 H_2/O_2 annunciators. When the Division 1 annunciators alarmed in the control room, the operators contacted the technicians and work was immediately stopped. Upon investigation, the crew determined that the steps in the WO were for lifting the annunciator leads for Division 1 instead of Division 2. The Division 1 lifted leads were reconnected, and a DER was written to evaluate the event. Subsequently, the Division 2 H_2/O_2 indication was repaired and declared operable on July 26.

Through discussions with maintenance and operations personnel, the inspectors ascertained that the lifted leads did not impact the operability of the Division 1 H_2/O_2 monitor. The inspectors verified this information by a review of applicable plant drawings and the Unit 2 UFSAR.

The apparent cause of the event, as described in DER 2-96-1754, was inadequate self-checking by the I&C Supervisor. Specifically, during performance of the WO, the I&C Foreman and Supervisor determined that the annunciator should be defeated (i.e., lifting the leads) to minimize disruptions of control room operations. To accomplish this, a WO change was made to incorporate steps from a previously approved procedure (N2-ISP-CMS-Q110). When incorporating the steps into the work order, the I&C Supervisor inadvertently copied the portion pertaining to the wrong division.

To assess the quality of NMPC's root cause and corrective actions, the inspectors reviewed the applicable WO, surveillance procedure, and DER, and discussed the event with the NMPC I&C Supervisor. The inspectors also reviewed the associated administrative procedure, GAP-PSH-01, "Work Control," Revision 15. GAP-PSH-01 states that if a change to an in-progress work order would adversely affect the scope or plant impact statement, the work must be stopped until the WO has been updated or another WO generated. Although the intended change would not have affected the original scope or plant impact; the implementation of the change did, in fact, adversely affect the scope and the plant impact statement. Therefore, the change was not made in accordance with GAP-PSH-01, Section 3.11.1, and is considered an example of a failure to properly implement the procedure. The violation is described in Section M4.5 of this report.

Although procedure GAP-PSH-01 allows minor WO changes to be completed by the supervisor without independent review, the inspectors considered the lack of independent review for determining whether a WO change is considered minor, and for determining the adequacy of the minor WO changes themselves, to be a vulnerability. The inspectors were also concerned that the technicians had possible opportunities to identify that the WO was directing work on the wrong division of

H_2/O_2 monitoring. In particular, the cabinet containing the annunciator leads was clearly marked Division 1, and should have prompted the technicians to question whether the step text of the work order was correct. This sort of questioning attitude is promoted by NMPC's "STAAR" (STOP, THINK, ASK, ACT, REVIEW) policy.

M4.5 Conclusion - Inadequate Personnel Performance

In sections M4.2 through M4.4, the inspectors described three maintenance related issues associated with poor personnel performance. These are: (1) a Unit 1 operator pulled the wrong fuses during the application of a markup, resulting in the inadvertent scram of a control rod; (2) a Unit 1 operator made a calculational error during completion of a core spray topping pump surveillance, resulting in a six week delay in identifying that pump differential pressure was higher than acceptance criteria; and (3) a Unit 2 I&C Supervisor made a minor change to a WO, but incorporated work steps for the wrong division of H_2/O_2 monitoring, resulting in maintenance on the wrong division. In each case, procedural requirements were violated as a result of personnel errors; and each is an example of a violation of TS 6.8.1, which requires procedures be properly implemented. **(VIO 50-220/96-10-04 & 50-410/96-10-04)**

In addition, relative to working on the wrong division of H_2/O_2, the inspectors considered the lack of independent review for a WO change to be a vulnerability. Also, the failure of the technicians to identify that the WO was directing work on the wrong division to be indicative of poor questioning attitude. Relative to the calculational error, supervisory reviews by the ASSS or the IST supervisor were inadequate in that they failed to identify that the core spray topping pump did not meet the surveillance test acceptance criteria.

M8 Miscellaneous Maintenance Issues (90712, 92700)

M8.1 (Closed) LER 50-410/96-08: Technical Specification Violations Caused by Inadequate Procedure

During preparations for RFO5, scheduled to begin September 28, 1996, Unit 2 personnel identified that the downscale rod block function of the source range monitors (SRM) had been inoperable during portions of the first four refueling outages. During core offload in the previous outages, as each SRM channel indicated downscale (i.e., less than 3 counts per second [CPS]), the rod block function relay was removed and jumpers were installed. This allowed removal of control rod blades. NMPC Unit 2 TS Table 3.3.6-1, note (f), permits the function to be inoperable during refueling, if the associated SRM channel is downscale. During the subsequent channel functional test prior to reload, the downscale rod block function was not tested. As fuel was loaded into the core, and the SRM channel came on scale, the rod block relay was installed in the affected channel. Per TS 3.3.6., the downscale rod block function was required to be operable prior to the SRM channel exceeding 3 cps.

The apparent cause of the missed surveillances was a misinterpretation of the TS requirement for the SRM downscale rod block function. No corrective actions were required since the event was discovered prior to the beginning of the RFO5, and the necessary changes were incorporated into the refueling procedures. This licensee identified violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

M8.2 <u>(Closed) LER 50-220/96-06: Technical Specification Violation Caused by Cognitive Error in Calculation Verification</u>

The inspectors reviewed LER 50-220/96-06 and determined that it satisfactorily described the event, the root cause evaluation, and corrective actions to prevent similar occurrences. As discussed in Section M4.3 of this report, a calculational error during a surveillance test resulted in the failure to identify that Core Spray Topping Pump 121 failed to meet the test procedure acceptance criteria. Specifically, the pump had high differential pressure (dp).

However, the procedure violation discussed in section M4.5, also caused NMPC to violate Unit 1 technical specifications since the pump should have been declared inoperable. TS 3.1.4.b states that if one pump is inoperable, the redundant component must be verified operable daily until the pump is returned to service, and the pump must be returned to service within 7 days. If the pump is not restored to an operable condition within seven days, TS 3.1.4.d requires the reactor be shutdown within one hour, and in a cold shutdown condition within the next ten hours. The failure to declare the pump inoperable when the results of the surveillance test were unacceptable is a violation of TS 3.1.4. The inspectors noted the high dp indicated the pump was performing in excess of the value required and the surveillance test was successfully performed once the calculational error was identified. Based on the corrective actions and low safety consequence, this licensee identified violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

III. ENGINEERING

E2 Engineering Support of Facilities and Equipment (37551, 40500, 93702)

E2.1 <u>Unit 2 Secondary Containment Pressurization</u>

a. <u>Inspection Scope</u>

On August 28, 1996, while at 95% power, Unit 2 operators entered the emergency operating procedures (EOPs) for "secondary containment control," due to positive pressure in the reactor building. The inspectors reviewed the description of the operators' actions as contained in the SSS logs, and reviewed the applicable EOP. The inspectors discussed the event, including the cause of the event, with shift personnel, the system engineer, and plant management. The inspectors also

reviewed the applicable TSs, UFSAR sections, DER, and plant drawings to assess the adequacy of the related plant design.

b. Observations and Findings

On August 27, 1996, Unit 2 operators declared the "A" train of the standby gas treatment system (GTS) and emergency recirculation ventilation unit cooler 413A (2HVR*UV413A) inoperable for the performance of the GTS functional surveillance test (N2-OSP-GTS-M001). This surveillance procedure required the unit cooler to be operated in the test mode. At 1:17 a.m. on August 28, the control room operators received a reactor building normal ventilation alarm, indicating reactor building pressure at +1.25" water gauge. Operators entered the EOPs for secondary containment control and TS 3.6.5.1 for secondary containment integrity as required. Initial indications were that the unit cooler test damper closed and the normal inlet damper opened. At 1:48 a.m. control room operators secured normal reactor ventilation and pressure returned to normal, allowing the operators to exit the EOPs and TS 3.6.5.1. Through a review of the SSSs logs, EOPs and TS, and discussions with the SSS, the inspectors determined the operators' response to the event to be appropriate.

As documented in DER 2-96-2038, the cause of the secondary containment pressurization was the shift in unit cooler 413A from the test mode to the emergency mode. In the emergency mode, the unit cooler was connected to the main exhaust duct for the "below refueling floor" exhaust subsystem. This placed the emergency ventilation system in parallel operation with the normal ventilation exhaust fan. Since the emergency system was recirculating air within the reactor building, less air was available for removal by the normal ventilation exhaust fan. This resulted in positive pressure within the secondary containment. The inspectors reviewed the applicable plant drawings, discussed the issue with the on-watch ASSS and the system engineer, and determined the cause to be reasonable.

Through discussions with the ASSS, the inspectors ascertained that the emergency ventilation unit coolers contained an interlock that caused the GTS inlet damper to open if the test damper closed while the system was running. The inspectors reviewed the applicable drawings with the ASSS and verified the circuitry associated with this interlock; based on this review, the inspectors determined that the emergency ventilation system responded as designed to the test damper failure. However, the inspectors review of the UFSAR, Section 9.4.2.5.3, noted that this particular interlock was not included in the description of the test damper operations.

NMPC performed troubleshooting and functional testing of the test damper and the associated circuitry under WO 96-12209-00. No problems were identified and failure could not be reproduced. The surveillance test was reperformed with no problems. Engineering provided the operators with an analysis supporting the operability of the emergency ventilation system. Subsequently, the emergency ventilation system and GTS were returned to an operable status, with the test damper in the closed position.

The inspectors reviewed the supporting analysis and determined it adequate for normal operations. However, the inspectors were concerned that the design of the test damper interlock allowed secondary containment pressure to become positive upon failure of the test damper during the performance of the surveillance test. According to DER 2-96-2038, a review to possibly change the procedure was requested as part of the supporting analysis. Therefore, until NMPC completes their analysis, and the NRC has reviewed the results, the adequacy of the surveillance procedure with regards to the potential for a failure of the test damper to result in a challenge to secondary containment integrity will remain an unresolved item. **(URI 50-410/96-10-05)**

c. Conclusions

The operators responded appropriately to the reactor building pressure transient that occurred as a result of the emergency ventilation unit cooler test damper failing shut during GTS surveillance testing. Review of plant drawings indicated that the emergency ventilation system responded as designed. The operability determination supporting analysis was determined to be adequate for normal operations; however, the adequacy of the surveillance procedure with regards to the potential for a failure of the test damper to result in a challenge to secondary containment integrity is unresolved.

E8 Miscellaneous Engineering Issues (90712, 92700)

E8.1 (Closed) LERs 50-220/95-05 and 50-220/95-05 Supplement 1: Building Blowout Panels Outside the Design Basis Because of Construction Error

a. Inspection Scope

LER 50-220/95-05 was originally reviewed in NRC Inspection Report 50-220/96-05. The LER accurately described the fact that oversized bolts were installed in the reactor and turbine building blowout panels; however, the following weaknesses were identified:

- the LER did not adequately address the failure to report the condition in October 1993, or in March 1995;
- the LER did not provide sufficient details regarding the 1993 calculational error to allow for an adequate assessment of the licensee's corrective actions to prevent recurrence; and
- the LER did not address the potential for, and the significance of, a reactor building failure.

The inspectors reviewed LER 50-220/95-05, Supplement 1, to determine if the above items were adequately addressed.

b. Observations and Findings

Supplement 1 to LER 50-220/95-05 provided additional details regarding the missed reportability requirements and the calculational error. NMPC's bases for not completing the required reportability notifications, and the technical details regarding the calculational error provided in the LER supplement, were consistent with those contained in Special Inspection Report 50-220/96-05. Additionally, the corrective actions included in the LER supplement appear comprehensive, in that the engineering, reportability, and configuration control aspects related to the issue were adequately addressed. The inspectors determined that Supplement 1 to LER 50-220/95-05 adequately addressed the reportability and calculational weakness identified during review of the original LER.

As described in the LER Supplement, NMPC reanalyzed the building failure pressures to determine the potential for, and the significance of, a reactor building failure. These analyses determined that the actual failure of the reactor and turbine buildings would not occur below an internal pressure of 143 pounds per square foot (psf) and 135 psf, respectively. Additionally, NMPC recalculated the upper bounding values for the blowout panels for both the original and currently installed configurations, using an elliptical methodology. The elliptical methodology is more appropriate for design of blowout panels, where a conservative upper-bound failure point must be established.

- Results of the calculations for original installation indicated the panel blowout point could have been as high as 128 psf and 122 psf for the reactor and turbine buildings, respectively.

- For the current installation, the calculations indicated the blowout points are a maximum of 65 psf and 62 psf for the reactor and turbine buildings, respectively.

These calculations were assessed by members of the NRR staff in August 1996, and determined to be acceptable. The results of the assessment were sent to NMPC in a letter, dated October 7, 1996. Based on the results of the analyses, NMPC determined that had a transient occurred, the blowout panels would still have functioned to relieve internal pressure before the calculated failure point of the reactor and turbine building superstructures.

c. Conclusions

The inspectors determined that the Supplement to LER 50-220/95-05 adequately addressed the weaknesses identified in the original submittal. Therefore, LER 50-220/95-05 and Supplement 1 to the LER are closed.

E8.2 Incorrect Safety Limit Identified by General Electric

a. Inspection Scope

On April 9, 1996, General Electric (GE) informed NMPC that the cycle specific safety limit minimum critical power ratio (SLMCPR), for both units, may be more limiting than determined by previously performed generic calculations. The inspectors assessed NMPC's actions in response to the GE information, including a review of applicable DERs, LERs, the TS, the 10 CFR Part 21 notification, and core operating limits reports (COLRs). Additionally, the inspectors discussed the issue with the plant managers, and engineers from NMPC's reactor engineering and fuels and analysis engineering departments.

b. Observations and Findings

On April 9, 1996, GE informed NMPC that cycle specific SLMCPR, for both units, may be more limiting than previously calculated. On April 10, NMPC contacted GE to discuss the information and ascertained that non-conservatism in the SLMCPR had been identified at several plants; NMPC determined that it definitely applied to Unit 2, but Unit 1 was not expected to be impacted. Furthermore, GE would be performing cycle specific calculations for both units. GE recommended that Unit 2 implement administrative controls to ensure compensation for the non-conservatism until the cycle specific calculations were completed.

On April 10, NMPC initiated a DER, common to both units, regarding the concern, and implemented administrative limits at both units until completion of the GE cycle specific analysis. Subsequently, the GE analysis determined that new SLMCPRs were needed for Unit 2, and Unit 1 as well. Both units updated the core monitoring computer to reflect the change in the SLMCPR, and the previous administrative limits were removed.

On May 24, 1996, GE notified the NRC, via letter, that the nonconservatism in the generic SLMCPR, when applied to some actual core and fuel designs, was reportable under 10 CFR Part 21. The inspectors reviewed the notification and verified that the actions taken at both units was appropriate. Therefore, the GE 10 CFR Part 21, "Reportable Condition, Safety Limit MPCR [minimum critical power ratio] Evaluation," for both units is closed.

As stated in the applicable LERs, NMPC evaluated the core performance for the current operating cycle. They determined that the operating limit, as adjusted to compensate for the error, was never exceeded, and that the safety limit would not have been exceeded for any analyzed plant transient. The inspectors discussed the evaluations with NMPC personnel and considered them appropriate.

The Unit 1 COLR will be updated by NMPC upon receipt of the revised supplemental licensing report from GE. The Unit 2 COLR revision incorporated the new limits, and appeared to be appropriate, containing the required reviews and approvals. Furthermore, the SLMCPR value specified in the Unit 2 TS, Section 2.1.2, will be

updated following restart from RFO5, scheduled for late October 1996. Until the revision is complete, the SLMCPR will be controlled administratively and limited by the core monitoring computer.

c. Conclusions

The inspectors observed the actions taken by both units in response to the nonconservative SLMCPR calculations provided by GE, and determined the actions were appropriate. Additionally, the inclusion of an administrative limit at Unit 1, even though GE initially indicated the Unit 1 was not expected to be impacted by the calculation error, indicated an appropriate safety focus.

E8.3 (Closed) LER 50-220/96-05: Incorrect Safety Limit Caused by Inadequate Calculational Procedure

The inspectors reviewed the subject LER and determined that it satisfactorily described the event, the root cause evaluation, and corrective actions. A detailed review of the issues associated with this LER is contained in Section E8.2.

E8.4 (Closed) LER 50-410/96-06: Incorrect Safety Limit Caused by Inadequate Calculational Procedure

The inspectors reviewed the subject LER and determined that it satisfactorily described the event, the root cause evaluation, and corrective actions. A detailed review of the issues associated with this LER is contained in Section E8.2.

E8.5 (Closed) LER 50-410/96-06 Supplement 1: Incorrect Safety Limit Caused by Inadequate Calculational Procedure

The inspectors reviewed the supplement to the subject LER and noted that the changes were editorial only.

IV. PLANT SUPPORT

The resident inspectors routinely monitored the performance of activities related to the areas of radiological controls, chemistry, emergency preparedness, security, and fire protection. No significant observations were identified during this period.

V. MANAGEMENT MEETINGS

X1 Exit Meeting Summary

At periodic intervals, and at the conclusion of the inspection period, meetings were held with senior station management to discuss the scope and findings of this inspection. The final exit meeting occurred on October 18, 1996.

Based on the NRC Region I review of this report, and discussions with NMPC representatives, it was determined that this report does not contain safeguards or proprietary information.

X3 Management Meeting Summary

X3.1 SALP Meeting

On August 8, 1996, a meeting between the NRC and NMPC management was held at the Joint New Center to discuss the results of Systematic Assessment of Licensee Performance (SALP), Report Numbers 50-220/96-99 and 50-410/96-99 for Nine Mile Point Units 1 and 2. This meeting was open to the public.

ATTACHMENT 1

PARTIAL LIST OF PERSONS CONTACTED

Niagara Mohawk Power Corporation

R. Abbott, Vice President, Nuclear Generation
J. Aldrich, Maintenance Manager, Unit 1
M. Balduzzi, Operations Manager, Unit 1
C. Beckham, Manager, Quality Assurance
J. Burton, Director, ISEG
J. Conway, Operations Manager, Unit 2
K. Dahlberg, General Manager, Projects
R. Dean, Manager, Unit 2 Technical Support
M. McCormick, Vice President, Nuclear Safety Assessment & Support
L. Pisano, Maintenance Manager, Unit 2
N. Rademacher, Plant Manager, Unit 1
R. Smith, Operations Manager, Unit 2
K. Sweet, Technical Manager, Unit 1
K. Ward, Technical Manager, Unit 2
D. Wolniak, Licensing Manager
W. Yaeger, Manager, Engineering, Unit 1

INSPECTION PROCEDURES USED

IP 37551:	On-Site Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 60605:	Preparations for Refueling
IP 61726:	Surveillance Observations
IP 62703:	Maintenance Observation
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support
IP 90712:	In-Office Review of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors
IP 92901:	Followup - Operations

ITEMS OPENED, CLOSED, AND UPDATED

OPENED

50-410/96-10-01	URI	Main steam line radiation monitor returned to service prior to being declared operable
50-410/96-10-02	URI	Service water design not fully analyzed for all accident conditions and service water header combinations
50-410/96-10-03	VIO	PCE procedure not consistent with the requirements of TS
50-220 & 50-410/96-10-04	VIO	Multiple examples of failure to follow procedures
50-410/96-10-05	URI	Standby gas treatment system interlock caused the containment to experience a positive pressure

CLOSED

50-220/95-03-01	VIO	Failure to follow procedures
50-220/95-03-02	URI	Procedures not consistent with TS
50-220/95-16-01	URI	Weak initial operability determinations
50-410/96-08	LER	TS violations caused by inadequate procedure
50-220/96-06	LER	TS violation caused by cognitive error in calculational verification
50-220/95-05	LER	Building blowout panels outside the design basis because of construction error
50-220/95-05-01	LER	Building blowout panels outside the design basis because of construction error
50-220/96-05	LER	Incorrect safety limit caused by inadequate calculational procedure
50-410/96-06	LER	Incorrect safety limit caused by inadequate calculational procedure
50-410/96-06-01	LER	Incorrect safety limit caused by inadequate calculational procedure
- - -	10CFR21	Reportable condition, safety limit MPCR evaluation

UPDATED

NONE

LIST OF ACRONYMS USED

ASSS	Assistant Station Shift Supervisor
BWR	Boiling Water Reactor
BWROG	Boiling Water Reactor Owners Group
CFR	Code of Federal Regulations
CIV	Containment Insolation Valve
COLR	Core Operating Limits Report
cps	counts per second
CRD	Control Rod Drive
CSL	Low Pressure Core Spray
CSO	Chief Shift Operator
DCR	Document Change Request
DER	Deviation/Event Report
dp	differential pressure
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
ESF	Engineered Safety Feature
FSAR	Final Safety Analysis Report
GE	General Electric
gpm	gallons per minute
GTS	Standby Gas treatment System
HCU	Hydraulic Control Unit
HPCI	High Pressure Coolant Injection
I&C	Instrument and Controls
IN	Information Notice
IR	Inspection Report
IST	In-service Testing
LCO	Limiting Condition of Operation
LER	Licensee Event Report
MCPR	Minimum Critical Power Ratio
MOV	Motor Operated Valve
MSIV	Main Steam Isolation Valve
MSL	Main Steam Line
NCV	Non-Cited Violation
NMPC	Niagara Mohawk Power Corporation
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NSSSS	Nuclear Steam Supply Shutoff System
PCE	Procedure Change Evaluation
psf	pounds per square foot
psia	pounds per square inch absolute
psig	pounds per square inch gage
QA	Quality Assurance
RCIC	Reactor Core Isolation Cooling
RFO	Refueling Outage
RPI	Rod Position Indication

RPO	Responsible Procedure Owner
RPS	Reactor Protection System
RRG	Regulatory Response Group
SIL	Service Information Letter
SLMCPR	Safety Limit Minimum Critical Power Ratio
SORC	Station Operations Review Committee
SOV	Solenoid Operated Valve
SRAB	Safety Review and Audit Board
SRM	Source range Monitor
SRV	Safety Relief Valves
SSPV	Scram Solenoid Pilot Valve
SSS	Station Shift Supervisor
STA	Shift Technical Assistant
STAAR	Stop, Think, Ask, Act, Review
TS	Technical Specification
UFSAR	Update Final Safety Analysis Report
URI	Unresolved Item
VIO	Violation
WG	Water Gauge
WO	Work Order