U.S. NUCLEAR REGULATORY COMMISSION

REGION I

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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 18, 1999 - September 11, 1999
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EXECUTIVE SUMMARY

Nine Mile Point Units 1 and 2
50-220/99-07 & 50-410/99-07
July 18, 1999 - September 11, 1999

This inspection report included aspects of licensee operations, engineering, maintenance, and plant support. The report covered an eight-week period of resident inspection.

Operations

A number of work control and operator performance problems contributed to the July 23, Unit 1 scram during post-maintenance testing of the turbine mechanical pressure regulator (MPR). Work planning and control were poor in that equipment malfunction contingencies were not sufficiently developed and discussed prior to the testing. The control room operators' decision to continue testing with anomalous MPR response was not conservative. (Section O1.2)

On August 1, shortly after Unit 1 was taken critical, an automatic reactor scram occurred when an intermediate range neutron monitor (IRM) range selector switch was repositioned. The cause was determined to have been worn IRM selector switch contacts. Operator response was appropriate. (Section O1.3)

The inspector identified a back fill isolation valve associated with the control rod drive system open, but not locked in accordance with the system operating procedure. Control room staff response and resolution of this valve control issue were slow. This minor procedure violation was not subject to formal enforcement action. (Section O2.1)

The inspectors found the Unit 1 high pressure coolant injection system and the Unit 2 high pressure core spray system were properly aligned to perform their required safety function. (Section O2.2)

Following the July 23, 1999, reactor scram at Unit 1, the operators did not adequately document plant activities in the control room log book. In addition, although the control room operator responded promptly to a dual motor-driven feedwater pump trip, the alarm response procedures were not followed. These minor procedure violations were not subject to formal enforcement action. (Section O3.1)

Although no operability or other safety concerns were identified, the core spray system and emergency diesel generator engineering support analyses files located in the Unit 1 control room were poorly maintained and did not readily support verification of the current status of corrective actions associated with each system. (Section O3.2)

The Unit 2 alarm response procedure (ARP) for high pressure core spray pump room flooding did not provide appropriate guidance to operators for pump suction swapover. These procedural deficiencies were not subject to formal enforcement action. In addition, the inspector identified a few Unit 1 high pressure coolant injection ARP procedure steps that could be enhanced. These ARP issues were properly dispositioned by the licensee. (Section O3.3)

Maintenance

At Unit 2, two examples of poor work planning for maintenance activities were noted. An emergency diesel generator was inadvertently started and a reactor building ventilation damper was inadvertently operated. The lack of attention to process details, including second checks/independent verification, contributed to these unplanned equipment actuations. (Section M1.1)

On September 3, following troubleshooting and repairs to the reactor coolant leakage detection systems, and expiration of the Technical Specification allowed outage time (AOT), NMPC requested and was granted a Notice of Enforcement Discretion (No. 99-1-005) to extend the AOT by 24 hours to permit completion of post-work testing, thus avoiding a Unit 2 shutdown. The plant staff successfully restored the leakage detection systems to an operable status within the NOED time limit. Contributing to the licensee's need for the NOED was the instrumentation and controls technicians' unfamiliarity with the laptop computer and associated software used for the post-work testing. (Section M1.2)

The Unit 1 engineering staff had developed an action plan to improve condensate demineralizer performance, due to a history of high differential pressure and basket element failure problems. However, NMPC was slow to plan and inspect the sixth basket strainer elements, in spite of the identified problems and the increased risk of strainer element failure and potential adverse unit impact. (Section M2.1)

The July 23, 1999, Unit 1 control rod scram insertion times satisfied Technical Specification limits. However, a few procedural guidance weaknesses were identified which may adversely impact the reactor engineering staff's program to accurately trend control rod insertion time performance. The reactor engineering staff appropriately documented these weaknesses for resolution. (Section M3.1)

Engineering

The engineering staff thoroughly evaluated the technical aspects of the July 23 dual feedwater pump trip, including maintenance rule applicability, and identified the most probable causal factors. Appropriate corrective actions were taken or initiated prior to unit restart for the identified concerns. The failure to properly calibrate the No. 13 feedwater control valve following the RFO 15 setpoint setdown modification, contributed to the July 23 dual feedwater pump trip, and was treated as a non-cited violation. This modification associated error resulted in an avoidable challenge to the control room operators. (Section E1.1)

The system engineers' periodic walkdowns and knowledge of their respective systems were adequate to support and maintain the Unit 1 high pressure coolant injection (HPCI) and Unit 2 high pressure core spray (HPCS) systems. The system engineers produced good quarterly system health reports which provided accurate summaries of system status and useful performance trend data. (Section E2.1)

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ATTACHMENTS

Report Details

Summary of Plant Status

On July 23, Nine Mile Point Unit 1 (Unit 1) automatically shut down (scrammed) during post maintenance testing of a turbine regulating system. During the plant startup on August 1, Unit 1 scrammed shortly after being brought critical as a result of intermediate range neutron monitor system spiking. On August 6, Unit 1 was returned to service and remained at full power through the end of the inspection period.

At the beginning of the inspection period, Nine Mile Point Unit 2 (Unit 2) was shutdown to address reactor core isolation cooling system problems (reference Special Inspection Report 99-06). Unit 2 restarted on July 23, and reached 100 percent reactor power on July 26. The unit remained at 100 percent power through the end of the inspection period.

I. Operations

O1 Conduct of Operations [1]

O1.1 General Comments (71707)

Using NRC Inspection Procedure 71707, the resident inspectors conducted frequent reviews of ongoing plant operations. The reviews included tours of accessible areas of both units, verification of engineered safeguards features (ESF) system operability, verification of adequate control room and shift staffing, verification that the units were operated in conformance with Technical Specifications (TSs), and verification that logs and records accurately identified equipment status or deficiencies. In general, the conduct of operations was professional and safety-conscious.

O1.2 Automatic Reactor Shutdown Due to Mechanical Pressure Regulator Failure (Unit 1)

a. Inspection Scope (71707)

On July 23, during post maintenance testing of the turbine mechanical pressure regulator (MPR) control, Unit 1 automatically scrammed from 100 percent power. The inspectors reviewed the operator logs, post-scram review documentation, and the sequence of events. Additionally, the event was discussed with Unit 1 operations and management personnel.

b. Observations and Findings

During the week of July 19, corrective maintenance was performed on the MPR. The maintenance included flushing the supply line and replacing the bean valve (fluid snubber) in the pressure regulator's feedback line. The MPR was tested with the linkage from the MPR to the turbine control valves disconnected. The linkage was subsequently

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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.

reconnected and the MPR post-maintenance testing was continued. The electronic pressure regulator (EPR) was removed from service and the MPR placed in service to control turbine pressure. When the MPR was initially placed in service small pressure oscillations were observed. In spite of these anomalous pressure oscillations, additional MPR manipulations were performed and pressure began rising rapidly, peaking at approximately 1040psig. Operator attempts to stabilize pressure were not successful resulting in a positive reactivity addition (due to the collapse of voids) and an increase in reactor power to the high flux automatic reactor scram setpoint.

No safety relief valves operated during the event. The high pressure cooling injection system initiated and started feedwater pump 12 (feedwater pump 11 was already operating). Within the first minute following the scram, feedwater pumps 11 and 12 tripped on low suction pressure (further discussed in Sections O3.1 and E1.1). Operators promptly identified the pump trips and restarted both pumps. Operators used the turbine bypass valves to control reactor pressure and initiated a controlled cooldown.

Licensee investigation identified that the MPR bean valve had a large quantity of anti-seize type material in the valve internals. The investigation team concluded that this material caused internal blockage and prevented pressure regulator feedback. Without pressure feedback, the MPR continued to demand a pressure increase and resulted in the unchecked reactor pressure increase.

Licensee review of this event identified a number of operator performance and work control problems. For example, the control room operators' decision to continue testing with anomalous MPR response was not conservative. In addition, the operator manipulating the MPR setpoint control switch did not wait a sufficient amount of time between setpoint changes to observe or verify a pressure response. NMPC initiated DER 1-1999-2498 to evaluate turbine pressure control operation. Following the scram, the reactor mode switch remained in REFUEL position until the reactor was in cold shutdown. The licensee identified that the mode switch should have been in SHUTDOWN after all rods were verified in and the scram signal was reset. This minor procedure violation was not subject to formal enforcement action. DER 1-1999-3496 was written to address this concern. One of the work control deficiencies identified by the licensee was that the work package documentation indicated that the EPR would be available, if there was difficulty in controlling pressure using the MPR. In actuality, the EPR could not be rapidly returned to service due to the long response time of the regulator. The licensee also identified that the pre-job brief did not sufficiently cover the potential plant impacts of postulated equipment problems.

c. Conclusions

A number of work control and operator performance problems contributed to the July 23, Unit 1 scram during post-maintenance testing of the turbine mechanical pressure regulator (MPR). Work planning and control were poor in that equipment malfunction contingencies were not sufficiently developed and discussed prior to the testing. The control room operators' decision to continue testing with anomalous MPR response was not conservative.

O1.3 Scram Due to Intermediate Range Monitor Spike (Unit 1)

a. Inspection Scope (71707)

During startup of Unit 1 on August 1, 1999, an automatic reactor scram occurred when intermediate range neutron monitor (IRM) hi-hi trip signals were received on two reactor protection system (RPS) channels. The inspectors observed scram recovery efforts and reviewed the operator logs, post-scram review documentation, and the sequence of events. The inspectors also discussed the event with Unit 1 operations and management personnel.

b. Observations and Findings

Approximately five minutes prior to the scram, the reactor had been taken critical. The operators were in the process of ranging-up IRM 11 to range 3, when spurious electronic noise spiking occurred on IRMs 12, 15, and 16. This spiking caused the receipt of IRM hi-hi trip signals on RPS channels 11 and 12 which resulted in the reactor scram. All control rods properly inserted and all safety related equipment operated as designed. Operators were observed to have properly followed scram response procedures.

Degraded (worn) contacts on the IRM 11 range switch were identified by the licensee as the cause of the electronic noise. The degraded contacts caused relay chattering which resulted in electromagnetic interference (EMI) in the IRM circuits. The inspectors noted that the IRM circuitry had a history of EMI sensitivity as evidenced by three previous scrams which were the result of IRM spiking on multiple IRM channels. DER 1-1999-2562 was initiated to evaluate the cause and corrective actions for this event. Corrective actions included cleaning the IRM range switches and installing some additional EMI electrical cable shielding. Acceptable operation of the range switches was demonstrated during post-maintenance testing.

c. Conclusions

On August 1, shortly after Unit 1 was taken critical, an automatic reactor scram occurred when an intermediate range neutron monitor (IRM) range selector switch was repositioned. The cause was determined to have been worn IRM selector switch contacts. Operator response was appropriate.

02 Operational Status of Facilities and Equipment

O2.1 Locked Valve Control Discrepancy (Unit 1)

a. Inspection Scope (71707)

The inspectors conducted frequent plant tours, and evaluated equipment configuration control.

b. Observations and Findings

On the evening of July 27, the inspector observed that valve 28.1-37, back fill isolation valve to the GEMAC reference leg fill from 12 CRD Pump, was open and unlocked. Procedure N1-OP-58, RPV Level Back Fill Injection System, Attachment 1 (valve line-up) requires operators to lock open the valve while the No. 12 control rod drive (CRD) pump is in service. The inspector discussed this observation with the assistant station shift supervisor (ASSS). The ASSS noted that procedure N1-OP-58, Step 1.2, did not direct operators to re-lock valve 28.1-37 following a CRD pump swap. Based on a log review, the inspector determined that operators had last swapped the CRD pumps on July 26 and had opened back fill valve 28.1-37 at approximately 12:45 p.m.

On the morning of July 28, the inspector observed that the valve had not been relocked and discussed this observation with the station shift supervisor (SSS). The SSS directed an operator to relock the valve and initiated DER 1-1999-2518. The inspector determined that the previously contacted ASSS had initiated a procedure revision, but did not have the valve relocked or have a DER generated, in the interim. The failure to lock open valve 28.1-37 following a CRD pump swap was a procedural violation of minor safety consequence, not subject to formal enforcement action.

c. Conclusions

The inspector identified a back fill isolation valve associated with the control rod drive system open, but not locked in accordance with the system operating procedure. Control room staff response and resolution of this valve control issue were slow. This minor procedure violation was not subject to formal enforcement action.

O2.2 Safety System Walkdowns (Unit 1 and 2)

a. Inspection Scope (71707)

The inspectors performed a walkdown of accessible portions of the high pressure coolant injection (HPCI) system at Unit 1 and the high pressure core spray (HPCS) system at Unit 2 and compared the actual system configurations with that described in plant drawings and operating procedures.

b. Observations and Findings

The inspectors found that the systems were properly aligned to perform their required safety function. Equipment operability and material condition, based on this walkdown, were acceptable. Minor equipment discrepancies were brought to the attention of the control room operators and system engineers. Corrective actions were timely and appropriate.

c. Conclusions

The inspectors found the Unit 1 high pressure coolant injection system and the Unit 2 high pressure core spray system were properly aligned to perform their required safety function.

03 Operations Procedures and Documentation

03.1 Operator Logkeeping and Procedure Use (Unit 1)

a. Inspection Scope (71707)

The inspector reviewed the control room logs associated with the July 23 reactor scram at Unit 1. In addition, the operator response to the dual feedwater pump trip was reviewed.

b. Observations and Findings

The inspector noted that operators did not document several plant activities or events which occurred immediately following the reactor scram, in accordance with station procedures and management expectations. For example, the 1600 and 1700 SSS log entries pertaining to the reactor scram and feedwater system configuration, respectively, were extremely brief and absent any apparent cause or explanation of the problems encountered. The inspector observed that numerous activities occurred between 1600 and 1700 that involved changes in core reactivity, changes in station output, changes in auxiliary equipment, unusual conditions, annunciator signals, and other information that is expected to be documented per station procedure GAP-OPS-01, Administration of Operations, Section 3.10.2.C. The inspector determined that these logkeeping deficiencies represented a violation of minor safety consequence, in that, much of the information valuable to post-trip evaluation and subsequent review of operator performance was available via the automatic data recorders and computer alarm and event sequence printouts. This procedure violation is not subject to formal enforcement action. Operations management acknowledged the inspectors' observation and initiated corrective action as documented in DER 1-1999-2466.

The inspectors noted, based on the sequence of events and alarm printouts, that the control room operator responded quickly to the dual feedwater pump trip. Within seven seconds, the control board operator restarted both feedwater pumps. Based on discussions with the operator, the inspector determined that the operator did not follow alarm response procedure N1-ARP-H3, "Reactor FW Pump 12 Trip Overload Suction Hi-Level," as written. Specifically, following a feedwater pump trip, the operator should place the feedwater pump control switch to STOP and allow the switch to spring return to NEUTRAL (the pumps will automatically restart, if the HPCI actuation signal is still present). The operator stated that he wanted to ensure both feedwater pumps restarted, so he took both pumps to RUN. In this case, since the HPCI actuation signal was present, operator action to start the pumps was not needed. The inspector determined

that this violation of procedure N1-ARP-H3 is of minor safety consequence, and is not subject to formal enforcement action.

c. Conclusions

Following the July 23, 1999, reactor scram at Unit 1, the operators did not adequately document plant activities in the control room log book. In addition, although the control room operator responded promptly to a dual motor-driven feedwater pump trip, the alarm response procedures were not followed. These minor procedure violations were not subject to formal enforcement action.

O3.2 Engineering Support Analyses Tracking and Control (Unit 1)

a. Inspection Scope (71707, 37551)

In preparation for plant restart following the July 23 reactor scram, the inspector reviewed a risk informed sample of engineering support analyses (ESAs) maintained in the Unit 1 control room ESA files.

b. Observations and Findings

The inspector selected ESAs performed for issues involving the emergency diesel generators (EDGs) and the core spray (CS) system. The files were observed to be poorly organized and the status of corrective actions was difficult for the inspector to ascertain from the file information available. A number of examples were identified and discussed with the responsible licensee representative. In each case, the inspector was provided information not present in the associated files that satisfied any potential operability or other outstanding safety concern. NMPC wrote DER No. 1-1999-3110 to address the condition of the ESA files and the need to better maintain, routinely review, or update the files to reflect the status of associated corrective action.

c. Conclusions

Although no operability or other safety concerns were identified, the core spray system and emergency diesel generator engineering support analyses files located in the Unit 1 control room were poorly maintained and did not readily support verification of the current status of corrective actions associated with each system.

O3.3 Review of Alarm Response Procedures (ARPs)

a. Inspection Scope (71707)

The inspector reviewed selected control room alarm response procedures for the Unit 2 high pressure core spray (HPCS) and Unit 1 high pressure coolant injection (HPCI) systems to verify that the response guidance was proper for the system conditions and that the actions prescribed would appropriately verify/correct system deficiencies.

b. Observations and Findings

The inspector noted that Step 4 of ARP 601/739 "HPCS PUMP ROOM FLOODING," directed the operator to shift the HPCS pump suction, without verification of the location of the leak, if the pump was operating in response to an initiation signal. The procedure also did not provide guidance when operating the pump in the test mode. The inspector noted that shifting the suction from the condensate storage tank (CST) to the suppression pool, depending on the location of a postulated leak in the HPCS room, could unnecessarily reduce the suppression pool water inventory or aggravate the leak. NMPC promptly revised the ARP to address this potential risk to the safety systems and initiated DER 2-1999-2456 to address the procedural deficiencies. These minor procedural deficiencies were not subject to formal enforcement action.

Inspector review of Unit 1 ARP "HPCI MODE AUTO INITIATE," identified a few areas where the response guidance could be enhanced to ensure the operators were provided with clearer steps to verify HPCI system response to an automatic initiation. The licensee initiated DER 1-1999-31A to further evaluate the inspector's observations.

c. Conclusions

The Unit 2 alarm response procedure (ARP) for high pressure core spray pump room flooding did not provide appropriate guidance to operators for pump suction swapover. These procedural deficiencies were not subject to formal enforcement action. In addition, the inspector identified a few Unit 1 high pressure coolant injection ARP procedure steps that could be enhanced. These ARP issues were properly dispositioned by the licensee.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Unplanned Equipment Operation During Conduct of Maintenance (Unit 2)

a. Inspection Scope (61726)

On two separate occasions this inspection period while conducting maintenance to troubleshoot and repair plant equipment, the NMPC maintenance staff inadvertently initiated automatic operation of plant equipment. The inspector reviewed the work control process for performing this maintenance and interviewed personnel associated with the work to evaluate NMPC's conduct of maintenance on station equipment.

b. Observations and Findings

On August 11, while performing troubleshooting activities associated with a limiting condition for operation (LCO) maintenance period on the Division 1 emergency diesel generator (EDG), maintenance personnel inadvertently started the EDG. Circuit leads were temporarily lifted to disable the starting circuit, however when personnel energized

an optic sensor in the circuit per the troubleshooting plan, an unanticipated redundant initiation signal was sent to the starting circuit and the engine started. The generator did not load and the EDG was properly secured by the operators.

On August 24, while replacing a relay to perform troubleshooting involving spurious reactor building exhaust fan trips, the "Fix It Now" (FIN) team caused a discharge damper for an idle fan to open. This action resulted in a reduction in building exhaust flow and subsequent increase in reactor building differential pressure. By design, the building is suppose to be slightly negative. The increase in reactor building pressure resulted in a brief unplanned entry into a TS LCO for reactor building differential pressure. Following the replacement of the relay, the system returned to its normal configuration and reactor building differential pressure was restored to normal.

In both cases, the development and review process for the maintenance tasks appeared to have been limited in scope. Poor review of system drawings contributed to these unplanned plant equipment actuations. In addition, second checks/ independent reviews of the work steps were less than effective.

c. Conclusions

At Unit 2, two examples of poor work planning for maintenance activities were noted. An emergency diesel generator was inadvertently started and a reactor building ventilation damper was inadvertently operated. The lack of attention to process details, including second checks/independent verification, contributed to these unplanned equipment actuations.

M1.2 Inoperable Reactor Coolant System Leakage Detection System and Subsequent Notice of Enforcement Discretion (Unit 2)

a. Inspection Scope (71707)

On September 2, 1999, Unit 2 entered TS 3.4.3.1.d, "Reactor Coolant Leakage Detection System," limiting condition for operation (LCO) which required that a shutdown be initiated within 24 hours, if either the drywell floor drain tank fill rate monitoring system or the drywell equipment drain tank fill rate monitoring system could not be made operable. Following troubleshooting and repair activities on September 3, NMPC requested and received verbal enforcement discretion for the TS 3.4.3.1 24-hour allowed outage time (reference NMPC letter, dated September 3, 1999, and Notice of Enforcement Discretion for NMPC Regarding Nine Mile Point Unit 2, No. 99-1-005, dated September 8, 1999). The inspectors reviewed the technical specifications, observed troubleshooting activities, and verified operator implemented compensatory actions described in the Notice of Enforcement Discretion (NOED).

b. Observations and Findings

The reactor coolant leakage detection systems required to be operable by TS are provided to monitor and detect leakage from the reactor coolant pressure boundary. The

instrumentation utilized to measure the drywell floor drain tank and equipment drain tank fill rates contains a common analog input module. Proper functioning of this module is required to maintain the leakage monitoring systems operable. The degraded performance of this module resulted in the control room indications for leak rate monitoring to become erratic. Other systems provide monitoring and leak detection for the operators, including the primary containment airborne particulate and gaseous radioactivity monitoring systems. NMPC evaluated conditions within the primary containment and determined that the indications were not indicative of reactor coolant leakage. In addition, operators were able to hand calculate the leakage rate by measuring the output voltage from the sump level instruments. By comparing previous values, NMPC determined that there was no change in reactor coolant system leakage.

Instrument and controls (I&C) personnel performed troubleshooting activities and determined that an input module relay card was the most probable cause of the erratic channel operation. The inspector observed performance of the post-maintenance testing following module replacement. I&C technicians performed the post-maintenance testing in accordance with N2-ISP-DER-R101, "Operating Cycle Calibration of Primary Containment Drywell Floor and Equipment Drain Leak Rate Instrument Channels." The inspector noted that during the installation of the test equipment, the licensee identified that the portable laptop computer, used to run the testing software, did not have the appropriate testing program installed. Following the loading of the appropriate computer software, the testing was completed satisfactorily. This computer problem delayed the completion of post-work testing and contributed to the licensee's need to request the NOED extended allowed outage time.

c. <u>Conclusions</u>

On September 3, following troubleshooting and repairs to the reactor coolant leakage detection systems, and expiration of the Technical Specification allowed outage time (AOT), NMPC requested and was granted a Notice of Enforcement Discretion (No. 99-1-005) to extend the AOT by 24 hours to permit completion of post-work testing, thus avoiding a Unit 2 shutdown. The plant staff successfully restored the leakage detection systems to an operable status within the NOED time limit. Contributing to the licensee's need for the NOED was the instrumentation and controls technicians' unfamiliarity with the laptop computer and associated software used for the post-work testing.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 <u>Condensate Basket Strainer Failure and Inspection Schedule (Unit 1)</u>

a. <u>Inspection Scope (62707)</u>

The inspectors reviewed and discussed with the system engineer the various preventive and corrective maintenance activities associated with the condensate basket strainers to ensure proper condensate and feedwater system flow requirements are maintained.

b. Observations and Findings

The Unit 1 condensate and demineralizer system strainers have a history of high differential pressure and basket element failure problems which have degraded the suction pressure to reactor feedwater pump booster pumps. The inspectors determined that NMPC has developed an action plan to improve the performance of the condensate demineralizer effluent strainers.

NMPC has ordered new strainer basket elements because cleaning of the installed baskets has been ineffective (strainer differential pressure continues to degrade). During strainer element inspection and changeout in June 1999, NMPC found that five of the six strainer basket elements had failed. The sixth (No. 12) strainer inspection was not scheduled until after the arrival of a new strainer element. The inspectors questioned the logic of delaying the last strainer inspection until a new replacement arrived, since a suitable replacement strainer element was available. The inspector highlighted to the plant staff that failure of the strainer basket element could allow foreign material and resin to enter the reactor vessel potentially causing heat variations and fuel damage. Prior to the conclusion of the inspection period, NMPC rescheduled the No. 12 strainer basket element inspection to the next convenient down power evolution and updated the action plan. The system engineer stated that monitoring of reactor chemistry indicated no foreign material had passed to the vessel, to date.

c. Conclusions

The Unit 1 engineering staff had developed an action plan to improve condensate demineralizer performance, due to a history of high differential pressure and basket element failure problems. However, NMPC was slow to plan and inspect the sixth basket strainer elements, in spite of the identified problems and the increased risk of strainer element failure and potential adverse unit impact.

M3 Maintenance Procedures and Documentation

M3.1 Control Rod Scram Timing Procedure (Unit 1)

a. Inspection Scope (71707, 37551)

As part of a post-scram assessment, the inspector reviewed the reactor engineering staff's control rod scram timing calculations. In addition, the inspector discussed these calculations and the quality of procedure N1-ST-R1, "Control Rod Scram Insertion Time Test," with the reactor engineering staff.

b. Observations and Findings

Technical Specification 4.1.1.c (2) requires that following each reactor scram from rated pressure, the mean 90% insertion time shall be determined for eight selected control rods. If the mean 90% insertion time of the selected control rods does not fall within the range of 2.4 to 3.1 seconds, an evaluation shall be made to provide reasonable

assurance that proper control rod drive performance is maintained. Following the July 23 scram, the reactor analyst selected the eight slowest control rods from the 30 channel strip chart recordings. Using these eight slowest rods, the analyst calculated the mean 90% insertion time as 2.67 seconds. The analyst considered his selection of rods conservative, as faster rod speeds provide greater margins to safety valve lifting following a postulated isolation transient (main steam line closure or turbine trip without bypass). The inspector noted that procedure N1-ST-R1 does not provide specific procedural guidance for the selection of eight rods. The inspector also observed that the absence of consistent rod selection criteria could result in less than optimal control rod performance trending. The reactor engineering staff initiated DER 1-1999-2533 to evaluate the potential biasing of the scram time sample population. In the interim, preliminary reactor engineering staff review concluded that all rods met TS maximum times and no adverse rod insertion time performance trend existed.

The inspector also observed that there is a 100 millisecond time delay in the strip chart recorder rod insertion timing start-up (this results in recorded rod speeds 100 milliseconds faster than actual). The inspector noted that the reactor engineering staff did not add the 100 milliseconds to the recorded rod speeds. However, 0.1 seconds is subtracted from the TS upper limit acceptance criteria. The inspector observed that this method currently satisfies the TS requirement, but does not provide accurate recorded values of rod speeds for trending purposes. The inspector determined that the reduced upper limit acceptance criteria (accounting for the recorder delay time) is not documented in procedure N1-ST-R1. Accordingly, this procedure could be unknowingly revised to align the acceptance criteria to the TS 4.1.1.c (2) values and the subsequently recorded rod speeds could be biased 100 milliseconds faster. NMPC incorporated this observation into DER 1-1999-2533 and was reviewing the procedure for additional clarification at the close of the inspection period.

c. <u>Conclusions</u>

The July 23, 1999, Unit 1 control rod scram insertion times satisfied Technical Specification limits. However, a few procedural guidance weaknesses were identified which may adversely impact the reactor engineering staff's program to accurately trend control rod insertion time performance. The reactor engineering staff appropriately documented these weaknesses for resolution.

III. Engineering

E1 Conduct of Engineering

E1.1 <u>High Pressure Coolant Injection (HPCI) System Response to the Unit 1 July 23 Scram</u>

a. <u>Inspection Scope (92700, 37551)</u>

On July 24, technical support initiated DER 1-1999-2467 to evaluate the conditions which resulted in the trip of both motor-driven feedwater pumps on low suction pressure following the July 23 Unit 1 reactor scram and HPCI initiation. The inspector reviewed

the technical support (engineering) staff's evaluation and corrective actions for this event.

b. Observations and Findings

The Unit 1 HPCI system is an operating mode of the reactor feedwater system which is provided to ensure adequate core cooling in the unlikely event of a small reactor coolant line break which exceeds the control rod drive system pump makeup capability. The HPCI system is not an engineered safeguards system and is not credited in any loss of coolant accident (LOCA) analysis. Accordingly, the HPCI system is not safety-related and not subject to emergency core cooling system (ECCS) single failure criteria. Technical Specification 3.1.8 does require an operable HPCI system, when reactor pressure is greater than 110 psig and reactor temperature greater than saturation temperature. Chapter VII, Section (I)(3.0) of the Updated FSAR describes the HPCI mode of the feedwater system as capable of providing a "continuous supply" of feedwater to the reactor. In addition, the current probability risk assessment model and individual plant examination identify the HPCI system as risk significant.

DER 1-1999-2467 identified that following the scram and subsequent reactor vessel low water level trip, the HPCI system initiated, as expected. After 13 seconds, both motor driven feedwater pumps tripped on low suction pressure. The low suction pressure condition immediately recovered and the control board operator restarted both pumps within the following seven seconds (reference Section O3.1, above). Based upon the Updated FSAR system description, the licensee was concerned that the HPCI pumps tripped during this transient and initiated an investigation to determine the cause and develop any necessary corrective actions.

To address the issues in DER 1-1999-2467, the plant staff's investigation included a HPCI system engineering design review. The licensee determined the following: (1) the motor-driven feedwater pumps automatically initiated, as designed; (2) the shaft-driven pump continued to provide feedwater flow during turbine coast down for approximately 3.2 minutes, as designed; (3) the full open position of the No. 13 flow control valve on the shaft-driven pump created a high flow demand which robbed feedwater system flow and contributed to the motor-driven feedwater pumps tripping on low suction pressure; (4) void collapse and the associated hydraulic effect following the reactor scram contributed to lower feedwater suction pressure; (5) once the shaft-driven pump coasted down low enough, the suction pressure switches for the feedwater pumps reset, allowing the operators to reset the feedwater pump breakers and restart the pumps; and, (6) 3.2 minutes was ample time for operator manual action to restore the tripped motor pumps.

The engineering staff concluded that the full open position of the shaft-driven feedwater control valve was caused by the flow controller output signal being saturated. The licensee's investigation determined that in the last refueling outage (RFO 15), NMPC installed a reactor pressure vessel (RPV) level set point setdown modification on the No. 13 feedwater flow control valve. The engineering staff developed this modification to avoid reactor vessel overfill events. The modification results in the flow controller changing the nominal level set point from 72 inches to a lower RPV level set point of 45

inches following a reactor scram. The investigation confirmed that the set point setdown feature worked, as designed, following the July 23 scram, except that the controller saturated. Engineering self-identified that during the controller modification, NMPC did not specify a controller 50mADC signal limit (clamp), such as used on the original controller. Thus, the modified set point controller output signal saturated at approximately 66mADC and required additional response time. The additional response time was needed for the controller and valve control instruments to recover their saturated condition so that they could move (close) the valve (to limit flow in this case). Instrumentation and controls (I&C) technicians verified this analysis and re-calibrated the No. 13 controller prior to plant start-up. The failure of the licensee to have properly calibrated the No. 13 flow control valve controller, was a violation of 10 CFR 50, Appendix B, Criterion V, "Instruction, Procedures, and Drawings." This severity level IV violation is being treated as a Non-Cited Violation, consistent with Appendix C of the NRC Enforcement Policy **(NCV 50-220/99-07-01).** This violation is in the licensee's corrective action program as part of DER 1-1999-2467.

Inclusive of the engineering staff's review was the determination that the low suction pressure trip of the motor-driven feedwater pumps was classified as a Maintenance Rule Functional Failure, per procedure N1-MRM-REL-104. The engineering staff determined that the reliability performance criteria was exceeded on the #12 HPCI train (a previous failure occurred on 5/26/98). However, the failure mechanism for the July 23 event (low suction pressure trip of a high safety significant, standby function) is common to both HPCI trains. Therefore, the engineering staff recommended that both trains of HPCI be transferred to (a)(1) status. The inspector observed that the maintenance rule aspects of this issue were appropriately evaluated.

c. <u>Conclusions</u>

The engineering staff thoroughly evaluated the technical aspects of the July 23 dual feedwater pump trip, including maintenance rule applicability, and identified the most probable causal factors. Appropriate corrective actions were taken or initiated prior to unit restart for the identified concerns. The failure to properly calibrate the No. 13 feedwater control valve following the RFO 15 setpoint setdown modification, contributed to the July 23 dual feedwater pump trip, and was treated as a non-cited violation. This modification associated error resulted in an avoidable challenge to the control room operators.

E2 Engineering Support of Facilities and Equipment

E2.1 <u>System Engineering Support of Unit 1 and Unit 2 Safety Systems</u>

a. <u>Inspection Scope (37551)</u>

The inspectors interviewed selected system engineers and reviewed their activities to monitor and enhance safety system performance, including maintenance rule applications. The inspectors also discussed the role of the system engineers in reviewing and maintaining the alarm response procedures.

b. <u>Observations and Findings</u>

Unit 1 uses different system engineers to provide support and monitoring of the high pressure coolant injection (HPCI) system, whereas the Unit 2 high pressure core spray (HPCS) system has a single systems engineering point of contact. The inspector learned that the primary responsibility for the HPCI system rests with the feedwater and condensate system engineer. The feedwater heater, feedwater control, and condensate demineralizer system engineers support their systems and the HPCI flowpath function.

Through discussions with the system engineers, the inspectors determined that their individual knowledge of their respective system and their familiarity with the maintenance rule were adequate to support and maintain the system. The condensate and demineralizer system engineer did exhibit some maintenance rule knowledge weaknesses and the HPCS system engineer demonstrated some minor misconceptions about support systems, but these items were promptly addressed by NMPC management through additional training. Each system engineer demonstrated a clear understanding of the current challenges to their systems and had improvement plans in place.

The system engineers produce a quarterly system health report which records various system performance trends, overall maintenance rule ranking, and material condition. The inspectors found that the system health reports also provided a good updated summary of system status and technical issue resolution or action plan.

The inspectors observed that each system engineer conducts periodic material condition and valve lineup walkdowns of their system(s). These walkdowns were appropriately documented in reports to engineering management. Inspector review determined that these walkdowns had identified some system problems. Walkdown summaries were included in the system health report.

c. <u>Conclusions</u>

The system engineers' periodic walkdowns and knowledge of their respective systems were adequate to support and maintain the Unit 1 high pressure coolant injection (HPCI) and Unit 2 high pressure core spray (HPCS) systems. The system engineers produced good quarterly system health reports which provided accurate summaries of system status and useful performance trend data.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of the licensee management on September 30, 1999. The licensee acknowledged the findings presented.

ATTACHMENT 1

PARTIAL LIST OF PERSONS CONTACTED

Niagara Mohawk Power Corporation

D. Bosnic	Manager, Operations, Unit Two
S. Doty	Manager, Maintenance, Unit One
F. Fox	Acting Manager, Maintenance, Unit Two
N. Rademacher	Manager, Quality Assurance
D. Topley	Manager, Operations, Unit One

INSPECTION PROCEDURES USED

IP 37550	Engineering
IP 37551	On-Site Engineering
IP 61726	Surveillance Observations
IP 62707	Maintenance Observations
IP 71707	Plant Operations
IP 71750	Plant Support
IP 92700	Onsite Follow-up of Written Reports of Non-Routine Events at Power Reactor Facilities
IP 92904	Followup - Plant Support
IP 92900	Followup - Engineering

ITEMS OPENED, CLOSED, AND UPDATED

OPENED AND CLOSED

50-220/99-07-01	NCV	Failure to have properly calibrated the No. 13 flow control valve controller during the setpoint setdown modification was a violation of 10 CFR 50, Appendix B, Criterion V.

LIST OF ACRONYMS USED

ARP	Alarm Response Procedure
ASSS	Assistant Station Shift Supervisor
CS	Core Spray
CST	Condensate Storage Tank
DER	Deviation/Event Report
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generators
EMI	Electromagnetic Interference
EPR	Electronic Pressure Regulator
ESA	Engineering Supporting Analysis
ESF	Engineered Safeguards Feature
FIN	Fix It Now
GAP	Generation Administration Procedure
HPCI	High Pressure Core Injection
HPCS	High Pressure Core Spray
I&C	Instruments and Control
IR	Inspection Report
IRM	Intermediate Range Monitor
LCO	Limiting Condition for Operation
LOCA	Loss of Coolant Accident
MPR	Mechanical Pressure Regulator
NCV	Non Cited Violation
NMPC	Niagara Mohawk Power Corporation
NOED	Notice of Enforcement Discretion
NRC	Nuclear Regulatory Commission
OP	Operating Procedure
RFO15	Refueling Outage
RPS	Reactor Protection System
SSS	Station Shift Supervisor
TS	Technical Specification
USAR	Updated Safety Analysis Report
Unit 1	Nine Mile Point Unit 1
Unit 2	Nine Mile Point Unit 2