U.S. NUCLEAR REGULATORY COMMISSION
REGION I

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Licensee:	Niagara Mohawk Power Corporation 301 Plainfield Road Syracuse, New York 13212
Facility:	Nine Mile Point, Units 1 and 2
Location:	Scriba, New York
Dates:	October 4, 1990 through November 14, 1990
Inspectors:	W. A. Cook, Senior Resident Inspector R. R. Temps, Resident Inspector R. A. Laura, Resident Inspector C. E. Sisco, Operations Engineer H. J. Kaplan, Operations Engineer
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11/30/90
Date

Inspection Summary: This inspection report documents routine and reactive inspections during day and backshift hours of activities including: plant operations; radiological protection; surveillance and maintenance; emergency preparedness; engineering and technical support; and safety assessment/quality verification.

Results: A violation of Technical Specification 6.8.1 was identified as a result of two instances of procedural noncompliance during the performance of safety related maintenance at Unit 2. Two unresolved items were identified for further review at Unit 1. One item involved emergency condenser operability and the second item involves implementation of a containment spray system Appendix J commitment. One non-cited violation was identified due to improper adjustment of a limiting safety system setting. An Executive Summary follows.

EXECUTIVE SUMMARY

Nine Mile Point Inspection Report 50-220/90-09 and 50-410/90-09

October 4, 1990 through November 14, 1990

Plant Operations: Unit 1 completed Phase II testing of the Power Ascension Testing Program (PATP) and entered the last phase. Operator response to two Unusual Events was good with timely and conservative actions. A non-cited violation was issued for a licensee-identified limiting safety system setting violation. Unit 2 operator control of equipment status during refueling outage work release was observed to be comprehensive. Improper clearing of a holdout tag resulted in an inadvertent initiation of the standby gas treatment system.

Radiological Protection: A review of Unit 1 and 2 Radiological Occurrence Reports (ROR) was performed and a progression of radiation worker performance problems was noted. The ROR program was judged to be effective in documenting these types of events. However, the inspection concluded more emphasis needed to be placed in evaluating trends from the RORs and implementing timely and effective corrective actions.

Surveillance and Maintenance: During the performance of safety related maintenance on hydraulic control units at Unit 2, the inspector noted that an improper torque wrench was used and the requirements of the associated radiation work permit were not followed. A violation was identified for failure to follow applicable administrative procedures. The inspector noted that the maintenance crew exhibited an unprofessional approach towards the performance of this safety related maintenance activity particularly when initially questioned about the adequacy of the work practices compared to the procedural requirements. A Unit 1 I&C technician failed to follow instructions in a surveillance procedure and inadvertently introduced an Anticipated Transient Without Scram/Alternate Rod Insertion (ATWS/ARI) scram signal. A root-cause evaluation on a hydrogen/oxygen monitor operability problem was reviewed and Niagara Mohawk was requested to revise the contributing factors and corrective actions section.

Emergency Preparedness: Two Unusual Events at Unit 1 were properly responded to by the control room operators.

Engineering and Technical Support: (Unit 1) Poor procedural control over a change to the emergency condenser (EC) isolation setpoints resulted in declaring the ECs inoperable and entering an Unusual Event until the setpoints were reset. This issue is unresolved.

Safety Assessment/Quality Verification: An overall declining performance trend was noted during this period. The principles of adherence to procedures stated in Station General Order 90-06 were not being fully implemented by station workers nor enforced by supervisory oversight. The Unit 1 containment spray system was walked down and its associated operating procedure reviewed. No physical discrepancies affecting system operability were noted. Several procedural discrepancies were noted, as well as potential contradictions of the safety evaluation for a 10 CFR 50, Appendix J commitment implemented during the past outage. This item remains unresolved.

DETAILS

1. Plant Operations (Modules 71707, 71710, 93702)

1.1 Unit 1

During this inspection period, Niagara Mohawk completed their self-assessment of Phase II of the Power Ascension Test Program (PATP). Following presentation of their assessment to the NRC Restart Assessment Panel, and with no objections raised by the Panel to further power escalation, the last phase (Phase III) of the PATP commenced on October 24. Overall operator performance and response to events continues to be good. At the end of this period, Phase III testing was nearing completion. A summary of major events with inspector observations and assessment follows:

a. On October 10, Niagara Mohawk made a 10 CFR 50.72 notification to report that the common high voltage power supply to the ion chambers associated with the Traversing Incore Probe (TIP) system had been found low (5 volts) versus its normal output of 95 to 105 volts. As a consequence, from September 13, 1990 to the time the condition was noted and corrected, necessary gain adjustments to the TIP instrumentation (to compensate for the low voltage) resulted in non-conservative thermal limits being determined. Niagara Mohawk determined that the reactor had been in operation above 25% power while the Maximum Total Peaking Factor (MTPF) may have been in excess of its limit of 2.90. As a result, the appropriate Average Power Range Monitor (APRM) gain adjustments, required by Technical Specifications (TS) when the MTPF is greater than 2.90, were not made. More specifically, with a non-conservative MTPF value the APRM gain adjustments required by TS 4.6.2.c (when MTPF is greater than 2.90) for the flow-referenced APRM scram, a Limiting Safety System Setpoint (LSSS) and rod block signals were not adjusted properly, in violation of the TS.

Separate investigations of this event were conducted by the resident staff, a Region I specialist, and by Niagara Mohawk. LER 90-21 contains the results of Niagara Mohawk's investigation of the event, its safety significance, and corrective actions taken. The staff has reviewed the LER and is in agreement with its analysis of the event and corrective actions taken.

The inspectors concluded that the safety significance of the non-conservative thermal limits was low. Even with the maximum estimated error of 10%, the plant was operated well within its safety limits even at 75% power, the power level at which the problem was discovered. However, had power escalation continued on to 100% with the condition undetected, thermal limits may have been exceeded. The safety significance of the non-conservative LSSS for the flow-biased scram setpoint was also low. Conservatism was built into these TS values and the accident analysis only takes credit for high flux scrams initiated at the high power setpoint of 120% of rated power. This value is well above the flow-biased setpoint for the power/flow conditions where this LSSS was presumed to have been violated. Even though the non-conservative setting of the flow-biased scram setpoint was a violation of TS 4.6.2.c, the violation was not cited because the criteria specified in Section V.G. of the NRC Enforcement Policy (10 CFR Part 2, Appendix C) were satisfied. Non-Cited Violation (50-220/90-09-01)

b. At 2:15 p.m. on October 26, an Unusual Event (UE) was declared. The event classification involved the loss of an engineered safety feature requiring shutdown in accordance with Technical Specifications (TS). Earlier that day, it was discovered that the differential pressure trip units, which initiate an automatic isolation of the Emergency Condenser (EC) steam supply valves in the event of a steam supply line break, were set nonconservatively. The isolation setpoint of 18 psid may have been too high to ensure proper isolation. As a result, both ECs were declared inoperable which required placement of the unit in cold shutdown within 10 hours per the TS action statement. The UE was declared per the unit's Emergency Action Procedures.

After declaring the ECs inoperable, the surveillance procedure (SP) used to set the trip units was revised to incorporate the recently determined and more conservative setpoint of 11.5 to 12.5 psid versus the previous value of 18 psid. Instrumentation and controls technicians working with the control room operators performed the revised SP expeditiously and at 5:45 pm the ECs were declared operable and the UE terminated. During the event, reactor power was decreased from 88% to 80%. Power escalation per the Power Ascension Test Program (PATP) was recommenced following termination of the event.

The resident inspector was present in the control room during declaration of the UE and observed performance of the SP for the #12 EC. The inspector determined that all actions were performed in an appropriate and timely manner. No performance problems in the handling of this event were identified.

c. On October 28, the control room operators attempted to achieve 100% reactor power and generator output. At approximately 621 MWe generator output, (98% reactor power) a turbine bypass valve commenced opening indicating that the turbine control valves were full open. Operators immediately took action to stop a further power increase and reduced reactor power to approximately 96% (615 MWe) to evaluate this unexpected system response.

Preliminary investigation by Niagara Mohawk and General Electric representatives indicated that the turbine control valves appeared to be full open and that the turbine bypass valves responded properly to the increased reactor power output and corresponding pressure increase. The inspector learned from Niagara Mohawk that a modification was performed on the high pressure turbine during the refueling outage to improve overall turbine efficiency by reducing internal bypass leakage. It appeared that this modification was successful; however, this operational response was not anticipated by the Niagara Mohawk staff.

The inspector considered operator actions to the observed system response to be proper and conservative. Niagara Mohawk's approach to resolving this system response concern via an engineering staff investigation in conjunction with GE support appears appropriate. Unit reactor power has been limited to approximately 96% until this issue is resolved by Niagara Mohawk.

d. At approximately 4:45 p.m. on November 12, the unit lost all offsite 115 KV power. The reactor was operating at 97% power at the time. As a result of the loss of 115 KV, both emergency diesel generators automatically started and picked up load on their respective buses (power boards 102 and 103). In addition, non-emergency 4160 V bus 101 lost power resulting in the tripping of the 13 recirculation pump. This caused a down power transient which operators stabilized at 78% power. Because of the loss of off-site power, an Unusual Event was declared and appropriate notifications made. This event also resulted in the loss of one 115 KV line feed to the adjacent James A. FitzPatrick Nuclear Power Plant.

The cause of the 115 KV loss was an apparent fatigue failure of the compression lug coupling for the primary side phase three to the 101N reserve transformer. The separation of this 5/8 inch diameter cable coupling and whipping in the high wind gusts (40 to 50 mph) caused a phase differential protective relay and lockout relay trip of both the 101N and 101S transformers' primary side (R10 and R40, respectively) and secondary side feeder breakers. Both transformers are normally cross-tied on the 115 KV reserve bus and thus the fault resulted in protective relaying removing both transformers from service.

After a detailed inspection of the 101S transformer and isolation of the 101N transformer, Niagara Mohawk personnel restored the 101S transformer to service at 10:38 p.m. that same evening. The R40 breaker was also closed-in which restored the 115 KV line feed to FitzPatrick. The 103 EDG was subsequently secured.

An inspector was present in the control room throughout the entire event. His assessment was that the operators acted promptly and effectively in identifying and isolating the problem and in ensuring the plant was stabilized. Other support groups acted effectively to allow subsequent restoration of power to the 101S transformer and termination from the UE. No performance problems were identified.

1.2 <u>Unit 2</u>

Core off-load was completed on October 11, and the core remained off-loaded throughout this inspection period to support outage maintenance activities.

a. The processing and control of plant equipment during the work release process was observed to be thorough and effective. During the Division I and II bus outages, SORC approved temporary procedures were utilized to remove and restore the electrical buses in a step by step manner. The bus outages were properly executed and were indicative of good preplanning.

b. On October 9, a standby gas treatment system initiation and secondary containment isolation occurred due to operator errors. Two operators were sent to clear a holdout tag on reactor building ventilation test damper (2HVR*AOD34B) and then open the damper. This was in preparation to place the ventilation system into the emergency recirculation/test mode of operation. The operators incorrectly cleared the holdout tag and opened the 'A' test damper in lieu of the 'B' test damper.

The B reactor building unit cooler was started and because the test damper was shut, a low air flow isolation occurred. The inspector reviewed LER 90-17 and Lessons Learned Transmittal 90-91 which evaluated the root cause of the event. Neither operator verified the proper equipment identification prior to clearing the holdout tag. The inspector concluded that increased attention to detail while clearing tags and performing independent verification was indicated.

c. The inspector reviewed Modification Work Request (MWR) No. 21087, Drywell Outage Ventilation and verified that the modification was being appropriately controlled per station procedures. The inspector noted that the work boundaries were properly isolated and tagged, affected control drawings were properly updated and that appropriate operating procedures were revised or being revised to address the new system modification. The inspector identified that the physical modification to the containment purge line had been completed and that temporary duct work was installed. However, the temporary duct work was not connected with the reactor building ventilation system at the time of the inspector's review. This work was in progress under a different MWR (No. 21117).

The inspector noted that there was no Equipment Status Log (ESL) entry for the containment purge system modification status. This was discussed with the control room operators and operations management. The inspector learned that they were aware of the work in progress and subsequently documented this work activity and system impact in the ESL.

2. Radiological Protection (Module 71707)

2.1 Unit 1

a. Review of Unit 1 Radiological Occurrence Reports (RORs)

The inspector conducted a review of the Unit 1 RORs on file for 1990 to assess program implementation and to obtain an overview of station worker adherence to proper radiation protection work practices. To date, 72 RORs have been issued by the Unit 1 Radiation Protection (RP) staff. The inspector noted, in general, that the ROR program was properly identifying and tracking corrective actions for radiological occurrences in accordance with Radiation Protection Implementing Procedure S-RPIP-9.3, Radiological Occurrence Reports, Revision 00. However, the effectiveness of the RORs with respect to trending and as a tool to improve performance in the radiation protection area could not be fully assessed. It was apparent to the inspector that the types of events being

documented throughout the year have been similar in nature and fall into three major categories. These categories are: poor worker radiation work practices; non-adherence to radiation work permit and posting requirements; and poor communication between all work groups and radiation protection personnel. The inspector noted no improving trend based upon the RORs reviewed.

The inspector discussed his review of the Unit 1 RORs with station RP management and Unit 1 Health Physics manager and determined that Niagara Mohawk management was aware of the inspectors concerns and the continuing performance problems reaffirmed by the inspector's review. Niagara Mohawk management stated that steps had been initiated to achieve improvement in this area. These steps included: the respective station department managers and supervisors will become more intimately responsible for followup and corrective actions generated for RORs involving their subordinates; more emphasis will be placed upon individuals for their own radiation protection practices and they will be held accountable for the same; more senior management involvement is planned to ensure enforcement of good RP practices; and more timely tracking and trending of RORs and contamination occurrence reports will be initiated to provide management more feedback on progress towards improvement.

The inspector concluded that Niagara Mohawk was aware of their recent and continuing performance problems in the radiation protection practices area and were instituting steps to improve performance.

2.2 <u>Unit 2</u>

a. A similar review of Unit 2 Radiological Occurrence Reports (RORs) was performed. To date, there was a total of 53 RORs for 1990. In general, the RORs were found to be well written and of sufficient detail to fully describe the problem. The inspector focused on the circumstances and root cause of each event rather than the total number of RORs. Three major areas of concern in radiation worker performance were identified: 1) Radiation workers were not adhering to radiation protection program requirements. Many of the RORs were initiated due to failure to obey radiation boundaries, failure to obtain a radiation work permit, failure to follow radiation work permit requirements and failure to properly control contaminated material; 2) Communications between the radiation workers

and radiation protection personnel were poor. The work scope performed under a specific radiation work permit was in some cases not well defined and not clearly understood at the prework conference by all personnel involved; 3) Worker radiation work practices were poor. This has contributed to many unnecessary skin contaminations and was also evident in the numerous spills caused by carelessness.

These weaknesses were discussed with the Unit 2 radiation protection supervisor and plant management. As with Unit 1 management, Unit 2 management has taken similar corrective action with emphasis on improving radiation worker awareness and sensitivity to the radiation program requirements. The inspector noted that the ROR program was being effectively implemented but that more emphasis on obtaining timely and effective corrective actions was needed. A strength noted by the inspector was that many of the RORs were identified by radiation protection personnel indicating effective problem identification and awareness of in-plant activities.

b. The inspector observed two separate instances during this inspection period of radiation workers not following station radiation protection requirements. One instance involved failure to follow Radiation Work Permit (RWP) requirements and is discussed in Section 3.2.a of this report. The other instance involved a site engineer who exited the restricted area and did not perform a whole body frisk prior to crossing the step-off pad. These observations indicate radiation workers need to be more sensitive to station requirements.

3. <u>Surveillance and Maintenance</u> (Modules 71707, 61726, 62703)

3.1 <u>Unit 1</u>

a. The inspector reviewed a Special Report, dated September 4, 1990, issued in accordance with the requirements of TS table 3.6.11-1.6 regarding the inoperability of the containment hydrogen monitor. The report dealt specifically with the inoperability of containment hydrogen monitor Channel 12 and that the inoperability was the result of incorrect wiring. Upon initial review of the report in September, the inspectors requested that Niagara Mohawk provide further information concerning the circumstances of the wiring error.

Niagara Mohawk performed a detailed root cause analysis and presented the results of this analysis to the inspectors at a meeting on November 9.

At that meeting, it was explained that a wiring error, in which two identically labelled leads were swapped during troubleshooting activities led to the hydrogen monitor inoperability problem. Niagara Mohawk's root cause evaluation concluded that contributing factors to this event were: 1) the leads in question were identically labelled; 2) there were inaccuracies in the electrical drawings; and 3) post-maintenance testing associated with the troubleshooting work request was inadequate. Three recommended corrective actions based on the contributing factors were also included in the report.

Following extensive discussion with the Niagara Mohawk personnel presenting the root cause analysis, it became apparent that the three contributing factors stated in the evaluation were too broad. It was specifically determined that the apparent root cause of the event was a wiring error introduced during undocumented lifting and relanding of the leads by contractor technicians during troubleshooting activities. Contributing to the problem were vague directions provided in the work request authorizing the troubleshooting and repair activities. As a result of the discussion, Niagara Mohawk committed to review the root-cause analysis and revise the contributing factors and recommended corrective actions.

The inspector concluded that while extensive research of the facts in this event appears to have been conducted, Niagara Mohawk did not identify the specific root cause of the event. Therefore inappropriate corrective actions could have been taken which might have allowed recurrence of similar events.

b. On November 14, an I&C technician performing a surveillance test failed to follow an instruction in the procedure. Specifically, procedure N1-IPM-R-036-101 stated to inform the operators prior to insertion of an ATWS/ARI signal. However, the technician did not inform the operators, and when he inserted the signal the operators were caught unaware. The inspectors determined that Niagara Mohawk's actions in response to this event were appropriate.

3.2 <u>Unit 2</u>

a. The inspector observed safety related maintenance performed on hydraulic control unit (HCU) 6-15. The work consisted of replacing the rubber diaphragm in the scram inlet and outlet valves, replacing the packing assembly in the HCU foot valve and cleaning of the strainers in the HCU directional control unit. The maintenance was performed by three maintenance mechanics and one chief technician.

Two instances of failure to follow procedural requirements were identified by the inspector. The maintenance crew used torque wrench #22-1035 to torque the scram valve air diaphragm cover fasteners to 18 foot pounds (ft-lbs). The inspector noted that the torque wrench had a special instruction sticker stating the calibrated range was valid from 30 ft-lbs to 150 ft-lbs. Thus, the maintenance crew used a torque wrench to torque fasteners to a value outside of the torque wrench's calibrated range. Administrative Procedure (AP) 5.3.1, Control and Calibration of Measuring and Test Equipment, step 5.4.6.a.4 requires workers to comply with special instruction stickers on measuring and test equipment. This failure to follow procedure is a violation of AP-5.3.1 and Technical Specification 6.8.1. VIOLATION (50-410/90-09-01)

b. The inspector identified a second example of failure to follow a procedure in that, the maintenance mechanics noted above performed work within a posted contaminated area and failed to don proper anti-contamination clothing as required by Radiation Work Permit (RWP) 905853-01A. HCU 6-15 was located in a posted and roped-off contaminated area. The inspector determined that the mechanics moved from working on HCUs outside the contaminated boundaries to inside the contaminated area and failed to adhere to the RWP requirements for anti-contamination clothing. This was a specific violation of the RWP which required a full set of anti-contamination clothing when working in a contaminated area. Administrative Procedure (AP) 3.3.2, Radiation Work Permit, step 5.7.1 states that radiation workers shall comply with the requirements of radiation work permits. This failure to follow procedure is a violation of AP-3.3.2 and Technical Specification 6.8.1. VIOLATION (50-410/90-09-01)

c. While the above stated examples of procedural non-adherences were of relatively low safety significance, they do reflect a careless and indifferent attitude towards station requirements on the part of the maintenance mechanics involved. In addition, they reflect poorly on supervisory oversight in the field.

These instances of procedural non-compliance were discussed with station management and the following corrective actions were initiated prior to the conclusion of the inspection period:

1. A radiological occurrence report was issued to investigate the RWP violation.

2. A post-use calibration check of the torque wrench was performed and reverification of all fasteners that were torqued was performed.

3. An accountability meeting was held with the maintenance personnel involved and disciplinary actions were taken.

4. The station manager conducted a meeting with his direct reports to emphasize personnel accountability and enforcement of station requirements.

d. The following surveillance and maintenance activities were observed by the inspectors and were found satisfactory:

-- Drywell vacuum breaker operability test per N2-OSP-ISC-M@002. During the performance of this test, good repeat backs of communications were used between the operators involved.

-- Standby Gas Treatment integrity test.

-- Testing of auxiliary relays in the Division I switchgear.

4. Emergency Preparedness (Module 71707)

As discussed in Section 1.1 of this report, two Unusual Events were declared at Unit 1 during this inspection period. The inspectors noted that these events were responded to properly and in accordance with station procedures. Operators promptly identified the emergency condition entry levels, properly declared and made appropriate notifications of the UEs and took prompt action to resolve the conditions leading to the events.

5. Engineering and Technical Support (Module 71707)

5.1 Unit 1

a. The inspector reviewed and concurred with the metallurgical report entitled, "Root Cause Investigation of Thermal Expansion Joint Cracking at Nine Mile Point One Nuclear Power Plant" - June 2, 1990. The investigation was performed by Failure Prevention Inc. to determine the cause of cracking in the bellows sections in 4 of 6 units removed from service in September 1989. The relief valves are located in the drywell and are designed to be activated in the event of an accident to protect the reactor vessel from overpressurization. On the basis of examining 2 of the bellows assemblies, the report concluded that the failure in the bellows

was due to stress corrosion cracking as the result of chloride and sulfur contamination found on the outside surface of the failed component. No contamination was found in the bellows which did not crack.

Prior to initiating the metallurgical investigation, the licensee completed a design review of the subject bellows assemblies with several consultants including Stone & Webster, and Pathway, the original supplier. The review was necessitated because, in addition to the bellows cracking, other deficiencies were noted, namely (1) severe corrosion in the juncture between bellows and the carbon steel, and (2) severe deformation of the bellows sections.

As a result of the design review which addressed all deficiencies, all six units were replaced with newly designed units. To correct the corrosion problem, the new units were fabricated using Inconel 625 for the bellows instead of type 321 stainless, and type 304 stainless for the flanges instead of carbon steel. The Inconel 625 agrees with the recommendations in the metallurgical report.

b. With reference to the Emergency Condenser (EC) setpoint problem described in section 1.1.b of this report, the non-conservative setting of the EC trip units was discovered prior to restart and power ascension testing of the unit. An engineer revising the EC full load surveillance test questioned the possible impact on flow characteristics of the EC steam isolation valves. These valves were replaced in 1986 with smaller sized valves. Evaluation of the engineer's concern identified that with the smaller size valve, the differential pressure achieved during a postulated steam supply line break would fall below the existing isolation setpoint of 18 psid, and the EC would not isolate as designed. As a conservative measure for startup, the surveillance procedure (SP) used to check the setpoint on the trip units was revised to set the units more conservatively at approximated 12 psid. However, at the same time, the Engineering Setpoint Document (ESD) was not changed nor was a DCR issued to reflect the change in setpoint. A review of the revised SP by a technical review committee identified the trip unit setpoints to not be in agreement with the ESD and the setpoints were changed back to the original value of 18 psid. The re-revised SP was performed prior to unit startup, however, cognizant personnel (the PATP test engineers) were under the impression that the new conservative values were in effect until October 26 when the non-conservative setting was discovered.

In assessing this event, the inspectors noted that the safety significance of an EC not isolating on a steam supply line break is low, in that this event is bounded by a study that shows that 10 CFR 100 limits would not be exceeded nor would core damage occur as a result of such an accident. While the discovery of non-conservative setpoints prior to startup is an example of good problem identification, the failure to change the ESD to reflect the new setpoints hindered the resolution of this finding. The inspectors will review the LER for this event when it is issued. This issue is unresolved (50-220/90-09-02).

6. Safety Assessment/Quality Verification (Modules 71707, 40500)

a. A negative performance trend in the area of procedural adherence was apparent during this inspection period. Several examples of failure to adhere to procedural instructions are identified in this report. Station General Order (SGO) 90-06 clearly states in step C.2 that procedures must always be adhered to. There is an apparent lack of effective supervisory oversight of workers in the field in the area of enforcing the concepts of SGO 90-06. Further, numerous other examples of failure to adhere to procedures were identified in the RORs of both units.

b. Engineered Safety Feature System Walkdown at Unit 1 (71710)

1) A thorough walkdown and inspection of the containment spray system to identify any equipment conditions and items that might degrade plant performance was performed as well as a review of the system's valve lineup procedure to verify that valves were in their correct position for current plant conditions. Lastly, the inspector conducted a detailed review of the various normal and off-normal sections of Operating Procedure (OP)-14, Containment Spray System Nos. 80 & 93, Revision 33, dated August 9, 1990, to ensure technical adequacy. The inspector's findings are listed below:

-- No hardware discrepancies which might degrade operability of the system were identified.

-- The system valve lineup in OP-14 was determined to match plant drawings and as-built configuration. The inspector verified that all appropriate instrument root valves were identified on the system prints and were included in the valve lineup sheets. No discrepancies in valve positions were identified.

-- A review of the current revision to OP-14 revealed several discrepancies:

a. A Temporary Change Notice (TCN) to section H.3 of OP-14 was made on October 22, 1990. The change involved the renumbering of steps in section H.3. The inspector identified that the change was not thorough enough in that several other sections of OP-14 which referenced specific steps in section H.3 were not changed to reflect the new numbering scheme.

b. With regard to the change referenced above, the inspector determined that contrary to Note 1 in section H.3, the EOP Coordinator was not informed that a change to that section had been made. The inspector noted that the placement of the note requiring notification is not amenable to ensuring compliance with it. This same condition exists in section H.8 of the procedure.

c. Steps H.4.1.4 and H.4.2.4 referenced incorrect flow instrument identification numbers.

d. The above items were referred to Niagara Mohawk. Items (a) and (c) were corrected by issuing TCNs to the procedure. Item (b) regarding the placement of the note is being reviewed by Niagara Mohawk for determination of a better method to ensure compliance with it.

2) The inspector reviewed section H.7 of OP-14 entitled, "Establishing a Water Seal on the Containment Discharge Isolation Valves." The containment spray system contains four loops, each of which supplies the spray headers in containment via an air-operated isolation valve and a downstream check valve. In a May 1988 safety evaluation, the NRC determined that the check valves did not meet 10 CFR 50 Appendix J requirements for leak testing, as the present configuration does not allow leak testing of these valves. For the present operating cycle, Niagara Mohawk received an exemption, via a safety evaluation dated March 20, 1990, to provide a water seal on the check valves in the event of a Loss of Coolant Accident (LOCA), in order to satisfy 10 CFR 50 Appendix J, Section III.c.3(b). To satisfy this commitment, Niagara Mohawk modified two air-operated valves in the system to leave them in the open position to allow cross-tieing of the primary and secondary spray loops. This was accomplished by modification number N1-89-131 and was supported by Niagara Mohawk Safety Evaluation (SE) 89-13. To further clarify their

methodology, the NRC staff was also provided a proposed revision, Number 32, to OP-14 which would provide instructions for establishing the water seal. The inspector's review of section H.7 and Niagara Mohawk's SE 89-13 revealed several significant discrepancies:

First, the proposed revision 32 of OP-14 submitted to the NRC staff for their review contained an extensive note and two steps, 7.1 and 7.2, to provide instructions on maintaining a water seal. When the inspector reviewed Rev. 33 to OP-14, it not only contained the above steps, but included additional steps (7.3 through 7.8) which appeared to describe an alternative or additional method of maintaining a water seal. However, these steps not only conflicted with steps 7.1 and 7.2, but described a water seal method not approved in the NRC's March 1990 Safety Evaluation. Additionally, when the inspector asked several operators to explain how they would implement section H.7, he received differing answers. It was apparent that this section was confusing to the operators. The inspector brought this concern to Niagara Mohawk management attention on November 9 and a temporary change to the procedure was issued that day to eliminate steps 7.3 through 7.8. Niagara Mohawk is currently investigating why the procedure was not revised correctly.

Secondly, revision 1 to Niagara Mohawk's Safety Evaluation 89-13, SORC approved on 11/17/89, stated that during certain operating modes, ". . . one or both of the intertie valves, 80-40 and/or 80-45, could be closed thus negating the water seal. During these periods, which are expected to be less than the allowable TS Limiting Condition for Operation (LCO) period, the Containment Spray System will be considered as in the LCO with operation in this mode limited to seven days." The NRC's March 1990 Safety Evaluation also endorses this commitment to enter the LCO during certain operating conditions. The inspector determined that Niagara Mohawk had not implemented this commitment either through incorporation into OP-14 or by a TS interpretation. Further, the inspector determined that the Unit 1 operations person responsible for the water seal revisions to OP-14 was not informed of Rev. 1 to the safety evaluation which added the LCO commitment. Niagara Mohawk is currently investigating why these procedural commitments made in their safety evaluation were not implemented.

Lastly, the ALARA report attached to Safety Evaluation 89-13 for changing valves 80-40 & 80-45 to manual operation stated that, "Valves 80-44 (SIC) and 80-45 are located in low dose areas (normally less than 0.2 mR/HR to 6 mR/HR) and are of minor radiological significance since the valves will be left open for all but routine system surveillance. In addition, operator action will not be required at the location of the valves in the reactor building to mitigate or recover from an accident." The inspector questioned the above contention as EOP-10, Drywell Flooding, which would be invoked in the event of a Design Basis Accident (DBA) LOCA, requires performance of Section H.8, Injecting Raw Water Into the Torus - Using Containment Spray Raw Water, of OP-14. Section H.8 requires operation of valves 80-40 and/or 80-45 at four different points in the procedure. This would require sending personnel out into the reactor building each time and, as the containment spray system piping becomes quite contaminated following operation in response to a DBA LOCA, could result in high radiation exposures to personnel. Further, the area might not even be accessible. The inspector requested Niagara Mohawk to investigate this concern and to determine if alternate procedural guidance is required in Section H.8 in the event valves 80-40 and 80-45 cannot be operated and to revise the ALARA review if necessary.

The inspector concluded that the three concerns stated above represented potential inadequate control and review of procedures. While the safety significance of these procedural deficiencies is low, the poorly writtem procedure could have introduced an unnecessary confusion factor to operators responding to a post-LOCA condition. Similar to the EC setpoint issue discussed in Section 1.1.b of this report, these discrepancies are indicative of a configuration control problem. Whether the two events are related will be determined after completion of Niagara Mohawk investigations. These three concerns remain unresolved. Unresolved Item (50-220/90-09-03)

7. <u>Licensee Event Report (LER) Review</u> (Module 92700)

7.1 <u>Unit 1</u>

The following LERs were reviewed and found satisfactory:

-- LER 88-01, Supplement 1, January 15, 1988, ISI program deficiencies.

-- LER 90-21, October 10, 1990, APRM flow-biased setpoints improperly set due to malfunctioning TIP power supply.

7.2 Unit 2

The following LERs were reviewed and found satisfactory:

-- LER 90-08, Missed chemistry surveillance caused by personnel error.

-- LER 90-09, Manual reactor scram due to condenser vacuum leak caused by a turbine instrument air line break.

-- LER 90-10, Surveillance tests not performed due to poor work practices and inadequate written communications.

-- LER 90-11, Shutdown cooling system isolation caused by inadequate procedural development.

-- LER 90-17, Standby gas treatment initiation due to personnel error.

8. Management Meetings (Modules 30703, 30702)

Management/Exit Meetings Conducted by Region Based Inspectors During this Inspection Period

Date	Subject	Report No.	Inspector
10/15-10/19	Maintenance Performance Assessment Team Inspection	50-220/90-81 50-410/90-80	Glenn Meyer, Team Leader

9. Preliminary Inspection Findings (Module 30703)

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