U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket/Report Nos.:	50-220/97-04 50-410/97-04
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:	May 18 - June 28, 1997
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EXECUTIVE SUMMARY

Nine Mile Point Units 1 and 2
50-220/97-04 & 50-410/97-04
May 18 - June 28, 1997

This integrated NRC inspection report includes reviews of licensee activities in the functional areas of operations, engineering, maintenance, and plant support. The report covers a six week period of inspections and reviews by the resident staff, and regional specialists in the areas of fire protection and licensed operator requalification.

PLANT OPERATIONS

Although the Unit 2 control room staff response to an automatic containment isolation signal was good; the failure on the part of a Unit 2 non-licensed operator to properly implement the procedure for the backwash of the reactor water cleanup (RWCU) filters resulted in the isolation, an engineered safety system (ESF) actuation. **(NCV)**

Unit 1 performed a plant shutdown, without incident, in response to the loss of drywell floor drain (DWFD) leak monitoring capability. During the shutdown, NMPC used appropriate judgement in inspecting and cleaning the DWFD sump to prevent recurrence of the event.

Material condition of the Unit 1 emergency diesel generators (EDGs), ancillary systems, and emergency power boards was good. The system engineer's initiative to track and trend EDG surveillance test results was good and provided very useful data. EDG system reliability was very good. However, the EDG piping and instrumentation drawings did not reflect actual plant configuration for several valves. **(NCV)**

The Unit 2 operator's identification of an abnormally high temperature within the high pressure core spray switchgear room was an example of good awareness to plant conditions.

NMPC identified that the Unit 2 procedure to establish shutdown cooling from the remote shutdown panel was inadequate, if required coincident with a loss of offsite power. The failure to have adequate contingency actions is contrary to the description provided in the UFSAR and is considered a violation of 10 CFR 50.59. This issue is similar to problems reviewed during an earlier NRC inspection, which are being considered for possible escalated enforcement. This item remains unresolved pending the completion of the NRC review of those items. **(URI)**

The Unit 1 licensed operator requalification training (LORT) program was satisfactory overall. Performance during the simulator scenarios was mixed; one crew performed very well, another was acceptable, and a third required remediation. Communications and supervisory command and control were as general areas for improvement. The ROs generally demonstrated good board awareness and board manipulations. Performance on written examinations and JPMs was generally good. However, several significant concerns were identified. (1) The rod position indicating system reliability on the simulator appeared

to be poor and could enable negative training; and, procedural guidance did not exist to determine whether the reactor would remain shutdown under all conditions. (IFI) (2) The written examinations were minimally acceptable and representative of low standards, which could lead to degraded operator knowledge and performance. (IFI) Other indications of low standards included: the annual examination had negligible followup on the Unit 1 feedwater overfill event from November 1996, which should have been addressed as part of the systems approach to training. Also, the operating tests did not include faulted or alternate path JPMs, and the simulator scenarios had few component failures following the major transients.

Although plant procedures for both units adequately reflect the TS requirements for completing SORC reviews of TS violations, the inspectors identified several examples of missed SORC reviews of TS violations associated with the administrative sections of the TSs. Pending further review, this item will remain unresolved. (URI)

ENGINEERING

Licensee identification of potential pressure locking of Unit 1 core spray containment isolation valves during surveillance testing, as a result of a more conservative valve factor, was appropriate. However, the initial evaluation in 1994 was weak, in that NMPC failed to recognize the potential for pressure locking during the surveillance test. The installation of the thermal relief modification during a forced outage was both prudent and appropriate.

A review determined that the staffing of the Unit 2 Independent Safety Engineering Group (ISEG) staffing over the last five years always met the TS requirements of five members. However, in two instances, it was noted that ISEG members attended training for extended periods; although training is a part of most job descriptions, the inspectors considered it less than prudent not to provide a replacement during these periods of extended absence.

NMPC's failure to identify and include the Unit 1 torus isolation valves seat ring and gasket in the Appendix J program allowed for an untested leakage path. (NCV) In addition, the event report was not submitted within thirty days, as required by 10 CFR 50.73. (NCV) The NMPC practice of issuing an LER supplement, in lieu of a new LER for a new event, does not appear to be consistent with the guidance in NUREG-1022.

In March 1997, Unit 1 identified degraded lower spring wedge latches on the core shroud tie-rod assemblies, caused by incorrect design assumptions. The failure to recognize the potential for the latches to experience significant loading and stresses resulted in latch failure through intergranular stress cracking corrosion. (NCV)

During their review of licensee event reports (LERs), the inspectors identified an event that had been reported to the NRC, in accordance with 10 CFR 50.72, as a condition outside of the design basis contained in the Updated Final Safety Analysis Report (UFSAR). However, an event report was not submitted, as required by 10 CFR 50.73. Discussions with NMPC personnel provided inconsistent information, particularly with respect to

whether the event was or was not a condition outside the design basis, and therefore, whether or not reportable under 10 CFR 50.73. (URI)

PLANT SUPPORT

At Unit 1, the installation of remote monitoring cameras in frequently toured high radiation areas (HRAs) was a good application of the philosophy of maintaining radiation exposure as-low-as-is-reasonably-achievable (ALARA). In addition, the ability to continuously monitor degraded equipment in HRAs could prove a significant ALARA benefit.

The performance of a Unit 2 control room shift crew in the simulator during an emergency preparedness drill was considered good.

NRC inspectors found the access gate to the Unit 2 refuel floor unlocked. This will remain unresolved pending completion of the NMPC deviation/event report (DER), and subsequent NRC review. (URI)

NMPC had good administrative controls for the proper storage of combustibles in the plant and for the control of hot-work. Fire protection equipment conditions and housekeeping were good. Recent initiatives taken by NMPC to improve emergency lighting were appropriate. Performance by the fire brigade during a fire drill was very good. The implementation of the licensee's program for increasing brigade members familiarity with the plants is a very good initiative. The training program provided for fire brigade members was well-organized and complete, and complied with NRC requirements for preparing fire brigade members to combat fires. The level of detail contained in the training was adequate for both the fire department personnel and the radwaste operators.The Quality Assurance audits focused appropriately on, and verified, selected fire program attributes for compliance with program requirements.

REPORT DETAILS

Nine Mile Point Units 1 and 2
50-220/97-04 & 50-410/97-04
May 18 - June 28, 1997

SUMMARY OF ACTIVITIES

Niagara Mohawk Power Corporation (NMPC) Activities

Unit 1

Nine Mile Point Unit 1 (Unit 1) was in a reactor startup at the start of this inspection period, returning to operation after a forced outage for maintenance. On May 18, the reactor was made critical, with full power achieved on May 23. On June 14, Unit 1 was shutdown due to the inability to monitor drywell floor drain leakage rate (see Section O1.3), and continued in the outage through the remainder of the period.

Unit 2

Nine Mile Point Unit 2 (Unit 2) started the inspection period at full power. On May 26, a problem with the level controller for the "A" reheater drain tank resulted in small power oscillations. On June 1, the unit was shutdown for repairs; investigation identified that repairs were not feasible at this time due to the manufacturing lead-time needed for a new baffle plate for the reheater. The reheater was isolated and maximum power was determined to be limited to 95% of full power. The unit was restarted on June 7, and 95% was achieved on June 12. Maximum power was maintained through the end of the inspection period.

Nuclear Regulatory Commission (NRC) Staff Activities

Inspection Activities

The NRC conducted inspection activities during normal, backshift, and deep backshift hours. In addition to the inspection activities completed by the resident inspectors, regional specialists conducted inspections and reviews in the areas of fire protection and licensed operator requalification. The results of the specialist inspections are contained in the applicable sections of this report.

Updated Final Safety Analysis Report Reviews

A discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (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; one exception was noted (see Section O2.3 for details).

I. OPERATIONS

O1 Conduct of Operations (71707, 90712, 92700) [1]

O1.1 General Comments

Using NRC Inspection Procedure 71707, the resident inspectors conducted frequent reviews of ongoing plant operations. Specialist inspectors in this area used other procedures during their reviews of operations activities; these inspection procedures are listed, as applicable, for the respective sections of the inspection report. 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 2 Reactor Water Clean-Up System Automatic Isolation

a. Inspection Scope

Unit 2 experienced an automatic containment isolation of the reactor water clean-up (RWCU) system. The inspectors monitored the performance of the control room crew during initial response and subsequent recovery actions. Follow-up inspector actions included review of the event notification, the deviation/event report (DER), and associated operating procedures; in addition, the inspectors discussed the event with Unit 2 management.

b. Observations and Findings

On June 13, 1997, the Unit 2 RWCU system automatically isolated due to a high differential flow; the inboard and outboard containment isolation valves (CIVs) closed, as designed. The high differential flow condition was the result of an operator's failure to isolate one of the RWCU filters during a strainer/demineralizer backwash evolution. Although the non-licensed operator was performing the evolution in accordance with the approved procedure and using the NMPC policy for placekeeping, the root cause analysis identified that two steps were missed which would have isolated the filter prior to draining. The failure to properly implement the procedure is a violation of Unit 2 Technical Specifications (TSs), Section 6.8.1. This non-repetitive, self-identifying, and licensee corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. **(NCV 50-410/97-04-01)**

The operators in the control room responded well, using the appropriately alarm response procedures and special operating procedures. Shift supervision maintained good control of shift personnel activities, including activation of the fire brigade when multiple fire panel alarms annunciated, due to steam leakage from the seal of

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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.

RWCU pump 1A. NMPC properly notified the NRC in accordance with 10 CFR 50.72.

The inspectors reviewed the event notification and associated DER (2-97-1773) and found them acceptable. Corrective actions included manual conductivity measurements until continuous recording capability was restored, repair of RWCU pump P1A, counseling of the operator involved relative to proper work practices, and review of the event with other operations personnel. The inspectors considered the root cause and corrective actions to be acceptable.

c. Conclusion

Failure on the part of a non-licensed Unit 2 operator to properly implement the procedure for RWCU filter backwash resulted in an automatic engineered safety feature (ESF) actuation and isolation of the RWCU system. (NCV) The response of the control room staff was good.

O1.3 Unit 1 Technical Specification Required Plant Shutdown

a. Inspection Scope

The inspectors monitored the licensee's activities in response to the shutdown of Unit 1 due to the inability to measure drywell floor drain (DWFD) leakage.

b. Observations and Findings

During quarterly surveillance testing, on June 12, of the Unit 1 DWFD system, the inboard CIV failed the stroke test. Specifically, the valve indicated dual position (i.e. both OPEN and CLOSED indications were lit) when the valve was supposed to be fully shut; the licensee declared the inboard CIV inoperable. The outboard CIV was subsequently closed, in accordance with TS limiting conditions of operation (LCO) requirements; therefore, NMPC was unable to pump down the DWFD sump.

On June 13th, all DWFD sump leakage monitoring capability was lost due to both DWFD sump level chart recorders reading off-scale high. TS LCO 3.2.5(b) requires that the plant be placed in cold shutdown within 24 hours if less than the minimum number of operable channels for monitoring DWFD leakage are available. Therefore, the licensee commenced a normal plant shutdown of Unit 1, and cold shutdown was achieved at 7:18 a.m. on June 14th. The inspectors noted that the plant shutdown occurred without incident and the plant was placed in cold shutdown within the TS LCO requirements.

Evaluation of the DWFD inboard CIV identified fouling of the valve seat from fine metal particulate, thus preventing the valve from fully closing. The valve seat was cleaned and flushed. Additionally, the licensee inspected the DWFD sump to determine the amount and type of foreign material. One to two inches of corrosion products was identified in the sump, which was removed prior to commencing reactor plant startup. The inspectors considered that the licensee used appropriate

judgement in both inspecting and cleaning the DWFD sump to prevent recurrence of the event.

c. Conclusions

The Unit 1 plant shutdown in response to loss of DWFD leak monitoring capability occurred without incident, and the plant was placed in cold shutdown within TS LCO requirements. NMPC used appropriate judgement in inspecting and cleaning the DWFD sump to prevent recurrence of the event.

O2 Operational Status of Facilities and Equipment (71707)

O2.1 Unit 1 Emergency Diesel Generator Engineered Safety Feature Walkdown

Background

The Unit 1 emergency diesel generator (EDG) system provides the standby source of electrical power for equipment required for mitigation of the consequences of an accident, for safe shutdown, and for maintaining the station in a safe condition under postulated event and accident conditions. The event and accident conditions include: (1) a loss of offsite power (LOOP), 2) a loss of coolant accident (LOCA) coincident with a LOOP, (3) a degraded grid voltage condition, and (4) a station fire. The Unit 1 EDG system consists of two identical, physically separate and electrically independent standby diesel generator units -- DG102 and DG103. DG102 and DG103 supply 4160 volts alternating current electrical power to power boards (PB) 102 and 103, respectively, during the above events. Each EDG has associated support systems, including fuel oil, starting air, combustion air intake and exhaust, lubricating oil, cooling water, and ventilation.

a. Inspection Scope

The inspectors conducted an engineered safety feature (ESF) walkdown of the Unit 1 EDG system to assess material condition and evaluate the ability of the system to perform its intended function. The walkdown included all accessible areas of DG102 and DG103, and PB102 and PB103. The inspectors also walked down the following EDG ancillary systems: fuel oil, starting air, lubricating oil and cooling water. The inspectors reviewed completed EDG surveillance tests for the last two quarters, EDG reliability and performance monitoring data, and applicable operating procedures. The inspectors discussed the ESF walkdown results with the EDG system engineer and the Station Shift Supervisor (SSS). Additionally, EDG system inservice testing (IST) was discussed with the IST supervisor.

b. Observations and Findings

Overall, material condition of the EDG system and power boards was good. Minor lube oil leakage was noted on both EDGs, with some oil noted under the EDG foundations. The inspectors discussed the leakage with the system engineer. The system engineer was aware of the leakage and informed the inspectors that EDG

operability was not affected nor did the leakage present a fire hazard. The inspectors also discussed the oil leakage with the SSS, who noted that excessive oil accumulation was prevented by good housekeeping practices, such as operators cleaning up the oil during routine rounds.

The inspectors reviewed the following completed surveillance tests: N1-ST-M4, "EDGs / PB102 and 103 Operability Test," Revision 24; N1-ST-Q16, "Emergency Diesel Generator Quarterly Test," Revision 05; and N1-ST-Q25, "Emergency Diesel Generator Cooling Water Quarterly Test," Revision 07. The surveillance tests were performed within required frequency, and the test results were satisfactory. The completed surveillance tests received timely review from control room supervision.

The inspectors reviewed Procedure N1-TDP-REL-0101, "Emergency Diesel Generator Reliability Program," Revision 01. The Shift Technical Advisor (STA) was responsible for recording the start and secure times for all EDG operations. This raw data was collected and compiled by the system engineer to track EDG reliability and availability. Also, the system engineer maintained a data base developed from periodic surveillance testing. The inspectors reviewed EDG performance history and reliability data for the last 20-, 50-, and 100-demands, and noted that three valid failures were identified since 1991. DG102 had one start failure and one load-run failure in 95 start demands, and DG103 had one load-run failure in 98 demands; from this data, both EDGs appeared to exhibit very good reliability. The inspectors considered the system engineer's initiative to track and trend all EDG surveillance test results was beyond the requirements of the program and provided very useful data.

The inspectors identified some disparities between the EDG piping and instrumentation drawings (P&ID) and actual system layout. Specifically, drain valves 79.1-56 and 79.1-57 (for DG102 and DG103 sumps, respectively) were shown on the P&ID and the NMP1 Material Equipment List. However, the valve lineup attachment sheet to operating Procedure N1-OP-45, "Emergency Diesel Generators," Revision 22, and surveillance test Procedure N1-ST-M4, identified these valves as air box drain valves, and these valves were labeled as such in the field. The air box drain valves were not shown on the respective EDG P&IDs. The system engineer stated that valves 79.1-56 and 79.1-57 were air box drain valves and were the proper valves to be manipulated, as required, per Procedures N1-OP-45 and N1-ST-M4, and that the function of verifying air box condition was being properly performed by operators in the field. Additionally, DG103 fuel oil pressure gage (PI-82-83) had a root valve (82-83P) in the field, but the valve was not identified on the root valve schedule (P&ID F45136C). These P&ID discrepancies were discussed with the system engineer, who was unaware of them and who initiated a DER (1-97-1843). In this case, the failure to ensure that the P&IDs reflected actual plant configuration is a violation of Title 10 of the Code of Federal Regulations, Part 50 (10 CFR 50), Appendix B, Criterion V. However, this violation is of minor significance and is being treated as a Non-Cited Violation consistent with Section IV of the NRC Enforcement Policy. **(NCV 50-220/97-04-02)**

Other components were lacking identification labels. However, the inspectors did not consider the lack of labelling an immediate safety concern, in that those components incorrectly labeled or not having any identification labels did not require operator manipulation (such as check valves and relief valves), nor were they referred in operating procedure N1-OP-45, emergency operating procedures, or alarm response procedures.

c. Conclusions

Material condition of the EDGs, EDG ancillary systems, and emergency power boards was good. The EDG system engineer's initiative to track and trend EDG surveillance test results was beyond program requirements and provided very useful data. EDG system reliability was very good. The EDG P&IDs did not reflect actual plant configuration for several valves. (NCV)

O2.2 Inoperability of the Unit 2 High Pressure Core Spray Switchgear Room Unit Cooler

On June 23, 1997, during a shift tour, an Unit 2 operator noted that the high pressure core spray (HPCS) switchgear room was warmer than normal. Investigation by the Unit 2 operations staff discovered that the HPCS switchgear room unit cooler was not controlling temperature, as designed. Appropriately, the SSS declared the HPCS system and the associated switchgear inoperable, and notified the NRC, in accordance with 10 CFR 50.72. The equipment failure was documented in a DER. Troubleshooting identified a failed temperature sensing element. The licensee repaired the temperature element and completed post maintenance testing per a maintenance work order (WO); after which, the SSS returned the HPCS switchgear and system to an operable status.

The inspectors identified no concerns during their review of the associated DER, event notification, and portions of the WO. Discussions with the Unit 2 maintenance staff indicated no prior problems with the failed component. The inspectors considered that the operator's identification of the abnormally high temperature within the HPCS switchgear room to be an example of good awareness to plant conditions.

O2.3 Inadequate Procedure for the Remote Shutdown of Unit 2 During a Control Room Fire Coincident with a Loss of Off-site Power

On June 7, 1997, NMPC identified that Procedure N2-OP-78, "Remote Shutdown System," Revision 10, was inadequate to establish shutdown cooling during a control room fire coincident with a LOOP. In particular, the procedure required the operators to close the recirculation pump discharge valves using the circuit breakers. However, the licensee determined that these valves were powered from non-emergency power supplies; these power supplies would not be available during a LOOP unless specific actions were taken to restore power. Upon identification of this condition, the SSS declared the remote shutdown system inoperable, in accordance with TS, and notified the NRC in accordance with 10 CFR 50.72.

During power operation, the drywell atmosphere is inerted with nitrogen; since the valves are located inside the drywell, local operation is not feasible. NMPC revised Procedure N2-OP-78 to initiate an alternate means of shutdown cooling. The operators were trained on the procedure revision, and the SSS returned the remote shutdown system to an operable status. The inspectors determined the licensee actions taken in response to this event to be appropriate.

The Unit 2 UFSAR, Section 9B.8.2.4, requires that administrative procedures, operating instructions, and operator training be provided for a fire event in the main control room or relay room. The failure to have adequate contingency actions established for shutdown cooling during a control room fire coincident with a LOOP is contrary to the description provided in the UFSAR and is considered a violation of 10 CFR 50.59. However, identification of this issue by the licensee was the result of corrective actions associated with similar problems reviewed during NRC inspection 50-410/97-05, which are being considered by NRC management for possible escalated enforcement. This item remains unresolved pending the completion of the NRC review of items identified in NRC Inspection Report (IR) 50-410/97-05. **(URI 50-410/97-04-03)**

O2.4 Unit 2 Alternate Shutdown Cooling

a. Inspection Scope

The description of alternate shutdown cooling (ASC) in the Unit 2 USFAR provides for a preferred system lineup and an alternative lineup to maintain core cooling should a failure of normal residual heat removal (RHR) shutdown cooling occur. The inspectors reviewed the UFSAR, and supporting documentation, related to the development of the procedure for shutdown cooling to determine if the design inputs were appropriate.

b. Findings and Observations

The Unit 2 UFSAR describes two different methods for establishing ASC assuming only one division of RHR is available. (1) The preferred method would be to take a suction from the suppression pool, through the RHR pump and heat exchanger, into the reactor vessel, then out the vessel through the safety relief valves (SRVs) back to the suppression pool. The estimated time to achieve cold shutdown using this method is 30 hours. (2) The alternate method uses the available RHR pump for suppression pool cooling, while the other pump in the same division (Division I - Low Pressure Core Spray or Division II - RHR pump "C") is then used for vessel injection, with flow out of the vessel through the SRVs. The estimated time to achieve cold shutdown using this method is 54 hours.

These methods are designed for use during a worst case single failure; i.e., the loss of one division of emergency power coincident with a loss of offsite power. This failure would make the normal suction path for RHR shutdown cooling unavailable due to the loss of power for one of the containment isolation valves. To resolve

apparent conflicts between the UFSAR and the operating procedure, the Unit 2 Independent Safety Engineering Group (ISEG) initiated DERs in 1993 and 1994.

DER 2-93-2969 was generated to resolve limitations in the original RHR operating procedure (N2-OP-31, "Loss of Shutdown Cooling") for methods of establishing ASC that were not formally proceduralized and for meeting UFSAR commitments regarding Regulatory Guide (RG) 1.139, "Residual Heat Removal System." NMPC's corrective actions included the development of special operating procedures (SOP) to address off-normal operating conditions. Specifically N2-SOP-31, "Loss of Shutdown Cooling," was developed to address the preferred and alternative methods of establishing ASC. The associated safety evaluation (SE 94-091) determined that no unreviewed safety question (USQ) existed even though the ASC methods were not formally proceduralized; this was based on the fact that the changes represented a clarification of the various methods already described in the UFSAR. Another result of the DER was a UFSAR revision for the use of Division I RHR for the alternate ASC; originally, only Division II was described in the UFSAR. The SE concluded that a USQ did not exist, since it was bounded by the original UFSAR analysis for ASC.

Since alternate ASC was estimated to achieve cold shutdown condition in 54 hours, an SE was performed to determine if this was in compliance with the guidance contained in RG 1.139. NMPC concluded that the preferred method of ASC provided for adequate redundancy and meets the guidance contained in the RG; i.e., that the cold shutdown condition would be achieved in less than 36 hours. In addition, the licensee determined that alternate ASC did not need to meet the requirements of RG 1.139, but was provided for operational flexibility. The inspectors considered the above conclusions to be acceptable.

DER 2-94-1915 was initiated by the ISEG to have engineering provide justification for permitting ASC with less than 4 SRVs open. Engineering justification was to include the minimum number of SRVs required open to establish and maintain a 7,450 gallon per minute (gpm) injection flow to the reactor vessel using ASC. In resolving the DER, NMPC engineering contacted General Electric (GE), owner of the patent rights for the Dikkers SRV, model number 8R10. GE provided test data for the SRVs indicating that each valve was able to pass 6,781 gpm of water without damaging the valve. Accordingly, two valves, as described in the procedure, could pass 13,562 gpm, well in excess of the design 7,450 gpm flow rate.

When implementing procedure N2-SOP-31 to align ASC using the preferred method, the majority of actions can be performed from the control room. An exception is the installation of jumpers for the RHR injection valve circuitry to make at least one of the two valves throttleable, the jumpers must be installed in the standby switchgear room. For a loss of offsite power, this area is readily accessible since this event does not result in fuel failure. For a design basis accident, projected dose rates for these rooms have been estimated (reference UFSAR Table 12.3-4) and entry into the standby switchgear room for completion of short duration activities is within established dose criteria.

As part of the DER review process, SORC reviewed the provided data and concurred on the evaluation. To access the possibility of discrepancies between licensing basis documents and the acquired data, a Calculation Impact Review Checklist was completed. Since the new data did not result in a change to the UFSAR, no additional SE was needed per the requirements of 10 CFR 50.59.

c. Conclusions

Through review of plant procedures and applicable sections of the UFSAR, the inspectors concluded that activities for establishing Unit 2 ASC were consistent with those described in the UFSAR.

O5 Operator Training and Qualification (71001)

O5.1 Unit 1 Licensed Operator Requalification Program

a. Inspection Scope

Inspectors reviewed the Unit 1 licensed operator requalification training (LORT) program using NRC Inspection Procedure 71001, "Licensed Operator Requalification Program Evaluation." The inspectors evaluated the adequacy of the annual operating and biennial written examinations, and the administration of the examinations to one staff crew and two operating crews using the criteria contained in NUREG-1021, "Examination Standards." The inspectors interviewed licensed operators, training instructors, and supervisory personnel. In addition, the inspectors reviewed the procedures for maintenance and activation of operator licenses, and verified that the requirements were met to reactivate inactive licenses. Administrative procedures and documents associated with the training program and its implementation were also reviewed.

b. Observations and Findings

Written Examinations

The inspectors reviewed six written biennial examinations (3 senior reactor operator (SRO), 3 reactor operator (RO)) prepared and administered by NMPC during this examination cycle. The examinations were acceptable; however, the level of difficulty was low. In general, the open reference examinations consisted of many direct look-up or memory-level type questions. In some cases, the question stem stated the reference required to obtain the answer. Listed below are examples of the type of questions that were used in the examinations reviewed:

- "The unit is at 93% power when a CONTROL ROD DRIFT (F3-2-6) alarm annunciates. Indications on the full core display show control rod 30-31 at position 44. This rod was originally at position 40. What is the correct action?"

In this case, the question stem stated the alarm response reference required to obtain the correct answer. Once referenced, the answer was quickly found under a short list of operator actions.

- "Which one of the following defines net positive suction head (NPSH)?"

- "Which of the following explains the potential consequences of not maintaining adequate level in the closed loop cooling makeup tank?"

Both of these questions were of minor safety significance and required only a basic generic knowledge of NPSH. The knowledge and abilities (K/A) rating for these questions is 2.8, on a 5.0 scale.

- "During power operation an electrical failure renders the Emergency Condenser (EC) Rad Monitors inoperative. Based on the above conditions, which one of the following statements is correct: ..."
  (Unit 1 Exam bank question Q105)

The only knowledge required to answer this question was the ability to use the TS table of contents to find the radiation monitor section. No interrelation of facts or knowledge were required to obtain the correct answer.

The inspectors noted that one of the operators, previously licensed on another boiling water reactor and unfamiliar with Unit 1, had been able to achieve a passing grade (80%) without reference to plant procedures. This indicated that a detailed understanding of Unit 1 was unnecessary to pass the exam.

There were many other examples of these types of questions on the exams reviewed. This was not in agreement with the guidance in the Unit 1 training manual (NTP-TQS-102 Rev.5 Sect. 3.6.3.a and b.) which stated "Direct look-up style questions are not allowed ... Questions which only require the recollection of facts or knowledge ... are considered memory level and are NOT acceptable." This represents an inspector follow-up item pending NRC review of the level of difficulty on subsequent requalification exams. (IFI 50-220/97-04-04) In response, facility training managers noted that the level of difficulty of Unit 2 exams were higher. Although unable to extensively pursue this assertion, the inspectors briefly reviewed some Unit 2 exams and found this to be generally true.

Simulator Scenarios

The inspectors concluded that the scenarios met the quantitative and qualitative requirements of the Examination Standards. The inspectors reviewed the three scenarios written by NMPC and administered during the week of the inspection. Critical tasks were well defined and effective in evaluating the crews. However, the scenarios in general had few component failures following the major transient. This led to an uneven scenario pace and tended to reduce scenario difficulty.

Job Performance Measures

The job performance measures (JPMs) reviewed met the qualitative guidelines of the inspection procedure. The sample reviewed included the JPMs administered during the inspection week, as well as a set of JPMs given previously to a randomly selected crew. The inspectors noted that none of the JPMs were faulted or alternate path JPMs, which tended to reduce the difficulty of the JPM sets. The Unit 1 training manual suggested that alternate path JPMs be used in exam sets.

Sample Plan

The inspectors reviewed two sample plans developed for the exams administered during the week of the inspection and concluded that the plans provided an appropriate sampling of the material taught throughout the two year training cycle and adequately sampled the items specified in 10 CFR 55 with the following exception. Although the plan identified the November 1996, feedwater overfill event, the inspectors noted that negligible testing was done in this regard. Only two written exam questions were somewhat related to the event, and no part of the simulator scenarios or JPMs addressed the event. It was noted that all operating crews received special training in feedwater level control. As part of the basis for the systems approach to training (SAT) for the LORT program, the inspectors concluded that some meaningful evaluation of the event and post-event training would have been appropriate.

Exam Administration

The inspectors observed the administration of operating exams (scenarios & JPMs) to one staff crew and two operating crews and determined exam administration was satisfactory. The operating exam consisted of 3 scenarios for each crew and 5 JPMs for each individual of the crew. The NRC examiners generally agreed with the facility evaluators' assessments. However, the NRC inspectors noted that the follow-up questioning after the scenario was very limited; even when individual or crew performance was weak or indicated uncertainty. For example, the inspectors witnessed one scenario in which the staff crew failed because of a missed critical task. Despite weak performance by the assistant SSS (ASSS), the RO, and the crew as a whole, only the RO was asked follow-up questions. The inspectors judged that follow-up questioning to probe weak, unsatisfactory, and questionable performance should have been performed (as long as reasonable limits are established to ensure operator stress was minimized) to better understand the relevant performance and knowledge concerns.

Simulator Fidelity

The Unit 1 simulator fidelity was satisfactory with the following exception. The inspectors were concerned with the behavior of the rod position indication system (RPIS) on the full core display. Following the reactor scram in each of four simulator scenarios, the RPIS indicated that some rods were not fully inserted after the scram was reset. Immediately following the reactor scram, the chief shift

operator (CSO) appeared to verify that all rods were in using the green back-lighting for each rod on the full core display and the REFUEL ONE ROD PERMIT light. After one scenario, the operator was asked how he verified the reactor was shut down under all conditions. The operator indicated that he had checked the full core display to verify all rods in; however, at least three rods were indicating at various positions throughout the scenario.

The inspectors were concerned about the potential for negative training; in that during the observed scenarios, the operators ignored an operational anomaly in which some rods indicated not fully inserted. The operators did not bring this to their management attention, nor did they validate using other means that this was an anomaly. During crew briefs conducted prior to the beginning of each scenario, the lead simulator evaluator discussed known simulator deficiencies but did not state that the RPIS malfunctioned at times. Following identification of this issue by the inspectors, a simulator deficiency report (DR 1-2146) was written by the training staff documenting unreliability of the RPIS system in the simulator.

The inspectors noted that Unit 2 had a procedure established for verifying the reactor was shutdown under all conditions, but such a procedure did not exist at Unit 1. The inspectors were concerned with the lack of procedural guidance for the Unit 1 operators for verifying the reactor shutdown under all conditions, especially in light of the RPIS behavior. The inspectors were told by the training staff that the in-plant system also had a tendency to malfunction, though much less frequently than the simulator. An additional problem related to RPIS was noted during the performance of a JPM, when an operator was required to verify rod over-travel using the red back-light and the light was too dim to be seen by the operator.

Due to simulator RPIS problems and the training staff statements concerning in-plant problems, the inspectors reviewed additional documentation on the RPIS system. The documents reviewed included pertinent UFSAR and TS sections, DERs, and an associated GE Service Information Letter (GE SIL). GE SIL 532 addressed a problem that involved a loss of the FULL IN indication from the RPIS following a scram. The GE SIL described the problem as a reduction in the magnetic strength of the rod position magnetic pickups caused by a temperature excursion following a scram, which resulted in a brief loss of FULL IN indication. A description of related problems at Unit 1 was described in DERs 94-2230, 96-1298, and 96-3000. The inspectors reviewed the DERs with operations management, quality assurance and system engineering. At the time of the inspection, plant management was still evaluating a plant modification based on the GE recommended repair. The RPIS reliability and operator procedural guidance to ensure that the reactor remains shutdown under all conditions represents an inspector follow-up item. **(IFI 50-220/97-04-05)**

Overall Exam Performance

The inspectors observed two operating crews and one staff crew during the week of the exam. Performance on the simulator scenarios was mixed. The staff crew was noted as needing remediation for their performance on one scenario. One of

the operating crews performed very well and the other operating crew was generally satisfactory. Command and control and communications (including 3-point communications) were identified by both the NRC inspectors and the facility evaluation team as general areas for improvement. The reactor operators generally demonstrated good board awareness and board manipulations.

Written exam performance was generally very good with most operators scoring in the upper 90 percentile, with only one failure for the exam cycle at the time of the inspection. This appeared to be indicative of the generally low level of exam difficulty.

Performance on JPMs was good for the three operators observed in-plant and the two operators observed in the simulator.

Remedial Training Program

The inspectors reviewed a sample of remediation records for individuals and crews who had failed cyclic, annual operating, and biannual written exams and determined this area to be satisfactory. The remediation packages reviewed appeared to be appropriate for the weaknesses demonstrated. An in-depth review was done of an SRO who needed an extensive remediation plan and was removed from shift for a period of time. The inspectors noted appropriate measures were taken to ensure the SRO was fully qualified prior to returning to shift. However, the need for additional individual remediation was initially slow to be identified. It was not until a third failure of the crew in the simulator that the individual was identified as having weaknesses which affected the crew as a whole. As a result, the Unit 1 training department implemented a program (OTG 96-05, "Shift Training Advisor and Operator Performance Improvement Guideline") in October 1996, which should more readily identify and remediate individual weaknesses.

Management Oversight

The inspectors reviewed management observation critiques and feedback reports for 1996 and 1997. The critiques written by the training staff were objective, contained many comments, and were very self-critical. Those written by plant management contained less constructive feedback and were not as self-critical. All comments made were reviewed and dispositioned by the training staff.

Exam Security and Validity

The inspectors reviewed the security measures taken by the facility for exam development and administration, and concluded that programmatic controls were satisfactory, with no indications of exam compromise. However, the NMPC procedure guideline for exam development specified that there be at least a 60% difference in questions/exam material maintained between exams administered. The training instructor responsible for development of the biennial written exam indicated that the written exams administered this year had not been verified to differ from the last biennial exams by at least 60%. The NRC inspectors and the

instructor later verified that the difference between the two exams was at least 60%. The operations training manager indicated that the guidelines established may not be sufficiently detailed and indicated that further guidance would be considered.

Operator Feedback

The inspectors reviewed the feedback records for the past two years. A tracking system was used to summarize operator feedback and the actions taken to resolve the comments received. The inspectors noted that many positive comments were made concerning the quality of the training received in addition to the areas that were identified as needing improvement.

Maintenance and Activation of Operator Licenses

The inspectors reviewed NMPC's programmatic controls for maintaining an active license and for reactivating a license while meeting the requirements of 10 CFR 55.53. The inspectors reviewed various training attendance records, operations records, and medical records. In addition, records were reviewed for six individuals who reactivated their licenses in the past year. No weaknesses or problems were identified. The inspectors determined that controls for maintenance and reactivation of operator licenses were good. The inspectors reviewed a sample of ten licensed operator medical files to ensure that medical exams were being conducted biennially. The inspectors determined that physical exams were performed biennially, as required by 10 CFR 55.21, with no identified weaknesses.

c. Conclusion

The inspectors concluded the Unit 1 LORT program was satisfactory overall. Performance during the simulator scenarios was mixed; one staff crew needed remediation, one operating crew performed very well, and another operating crew performed acceptably. Communications and supervisory command and control were identified by both the NRC inspectors and the NMPC evaluation team as general areas for improvement. The ROs generally demonstrated good board awareness and board manipulations. Performance on written examinations and JPMs was generally good.

However, the following concerns were identified. (1) The written examinations were minimally acceptable and representative of low standards, continuing to administer written examinations meeting minimum standards could lead to degraded operator knowledge and performance. (IFI) (2) The RPIS reliability on the simulator appeared to be poor and could enable negative training. And, procedural guidance did not exist to determine whether the reactor would remain shutdown under all conditions, a subsequent decision when RPIS malfunctions. (IFI)

Further, the inspectors identified other indications of low standards. The annual examination had negligible followup on the Unit 1 feedwater overfill event from November 1996. This should have been addressed as part of the SAT basis for the

LORT program. Also, the operating tests did not include faulted or alternate path JPMs, and the simulator scenarios had few component failures following the major transients.

O7 Quality Assurance in Operations (40500, 71707)

O7.1 Station Operations Review Committee Review of DERs

a. Inspection Scope

The inspectors reviewed selected DERs to determine whether required Station Operations Review Committee (SORC) reviews were being completed in accordance with the TS and applicable procedures. Particularly, that all TS violations were reviewed by SORC.

b. Observations and Findings

TS 6.5.1.6, for both units, requires that all TS violations be reviewed by SORC. Procedure GAP-SRE-02, "Station Operations Review Committee," Revision 00, states that SORC shall investigate violations of TS per Procedure NIP-ECA-01, "Deviation/Event Reports." Procedure NIP-ECA-01, Revision 11, requires SORC review of all reportable events, TS violations, and other issues at the discretion of the Plant Manager. The inspectors determined that the procedures appropriately reflected the TS requirements.

Based on a list of DERs requiring SORC reviews, the inspectors selected 34 of the 859 Unit 1 and Unit 2 closed DERs identified as requiring SORC review, to determine whether the licensee was performing the required reviews. All of the selected DERs generated within the last two years were verified to have received the required SORC review. However, the inspectors noted weaknesses with the information obtained from the DER data-base for some of the older DERs. Particularly, cases were noted where the data-base indicated that the SORC reviews were not completed; however, the hard-copy of the DERs indicated that the reviews were completed. Also, one case was noted where the data-based indicated that a SORC review was required; however, the DER indicated that SORC review was not required.

To determine whether the SORC require reviews of TS violations were completed, the inspectors reviewed a list of closed DERs generated within the last two years that contained the word "violation" within the title. Thirty-six DERs not marked as having a SORC review completed, but that had the potential for being TS violations, were selected for further evaluation. During the evaluation of the selected DERs, the inspectors identified no examples in which violations of the technical sections of the TS (sections 2.0, 3.0, and 4.0) were not reviewed by SORC. However, the inspectors identified several examples in which violations of the administrative section of TS (section 6.0) were not reviewed by SORC, including:

- DERs 2-96-1367, 2-96-2905, and 2-96-2839 associated with failures to meet Unit 2 TS 6.2.2.i requirements regarding overtime;

- DERs 2-95-0539 and 2-96-2207 associated with failures to meet Unit 2 TS 6.11 requirements regarding radiation protection program;

- DER 2-96-2987 associated with failures to meet Unit 2 TS 6.8.2 regarding procedure changes; and

- DER 1-96-1255 associated with a failure to meet Unit 1 TS 6.8.1 requirement regarding procedure implementation.

During the review, the inspectors also ascertained that DER 1-94-2504 identified examples (1991 through 1994) where NMPC failed to complete SORC reviews of TS violations associated with overtime at Unit 1.

The inspectors discussed the missed SORC reviews with the Quality Assurance (QA) Manager, and the SORC coordinators and Plant Managers for both units. The Plant Managers indicated that it was their understanding that the SORC review did not apply to all administrative TS violations, particularly violations associated with procedure implementation. The Plant Managers expressed a concern that SORC review of all procedure implementation violations would redirect SORC focus from more safety significant activities. Based on NMPC comments, the inspectors determined that additional review was required. Therefore, the above examples of missed SORC reviews of TS violations associated with the administrative sections of the TS remains unresolved pending further evaluation by NRC.
(URI 50-220/97-04-06 & 50-410/97-04-06)

c. <u>Conclusions</u>

Although plant procedures adequately reflected the TS requirements for completing SORC reviews of TS violations, the inspectors identified several examples of missed SORC reviews of TS violations associated with the administrative sections of the TSs. (URI)

O8 Miscellaneous Operations Issues (90712. 92700)

O8.1 <u>(Closed) LER 50-220/96-11: Reactor Scram Caused by the Main Generator Lockout Relay Trip</u>

A detailed review of the issues described in this licensee event report (LER) is contained in NRC IR 50-220/96-13, Section O2.3. The inspectors initially reviewed the subject LER in NRC IR 50-220/96-14 and determined that it satisfactorily described the initiating event of the generator trip and subsequent reactor scram. In addition, the root cause and corrective actions for the generator trip and reactor scram, as described in the LER, were described accurately and considered acceptable. However, at that time, the overall assessment of the root cause analysis and corrective actions was left open pending the enforcement conference

related to the reactor overfill event associated with the reactor scram. The inspector reviewed the final root cause analysis and proposed corrective actions described in the NMPC response to the Notice of Violation for the overfill event.

In the response to the Notice of Violation (dated May 12, 1997), NMPC determined the root cause for the overfill event to be NMPC management's insensitivity to reactor pressure vessel overfill events; leading to a failure to adequately self-evaluate shift performance, corrective actions, procedure compliance, and crew responsibilities. Corrective actions, both completed and planned, included repair of the flow control valves, enhancing procedures for scram recovery and emphasizing the proper use of procedures, and training on the changes. The root causes and corrective actions for the overfill event, as described above, appear adequate. This LER is closed.

O8.2 <u>(Closed) LER 50-410/97-04: Reactor Water Cleanup Isolation on High Differential Flow Caused by Personnel Error</u>

The event was discussed in Section O1.2 of this inspection report. The description in the LER was consistent with the inspectors' understanding of the event, and the root cause analysis and corrective actions appear appropriate. This LER is closed.

O8.3 <u>(Closed) LER 50-220/97-06: Technical Specification Required Shutdown Because of Loss of Reactor Coolant System Leakage Monitoring Ability</u>

The event was discussed in Section O1.3 of this inspection report. The description in the LER was consistent with the inspectors' understanding of the event, and the root cause analysis and corrective actions appear appropriate. This LER is closed.

II. MAINTENANCE [2]

M1 Conduct of Maintenance (61726, 62707)

M1.1 <u>General Comments</u>

Using NRC Inspection Procedures 61726 and 62707, the resident inspectors periodically observed plant maintenance activities and performance of various surveillance tests. Specialist inspectors in this area used other procedures during their reviews of maintenance and surveillance activities; these inspection procedures are listed, as applicable, for the respective sections of the inspection report. In general, maintenance and surveillance activities were conducted professionally, with the work orders (WOs) and necessary procedures in use at the work site, and with the appropriate focus on safety. Specific activities and noteworthy observations are

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[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."

detailed in the inspection report. The inspectors reviewed procedures and observed all or portions of the following maintenance/surveillance activities:

- N1-EMP-SB-260 — 24/48 VDC [volts direct current], 250 VDC, and 125 VDC Batteries - Cell and Connector Replacement, Revision 7
- N1-FPM-LOG-A001 — Battery Emergency Light Test, Revision 2
- N1-FST-FPL-SA008 — Low Pressure Carbon Dioxide [CO_2] System Functional Test, Revision 4
- N1-FST-FPP-C003 — Fire Damper Operation and Inspection, Revision 0
- N1-FST-FPW-C003 — Fire Protection Pre-action and Automatic Sprinkler Test, Revision 0
- N1-OP-21A — Fire Protection System - Water, Revision 4
- N1-OP-21E — Fire Protection System - Fire Detection, Revision 3
- N1-ST-M4 — EDGs / PB102 and 103 Operability Test, Revision 24
- N1-ST-Q16 — Emergency Diesel Generator Quarterly Test, Revision 05
- N1-ST-Q25 — Emergency Diesel Generator Cooling Water Quarterly Test, Revision 07
- N2-FPM-FPM-V001 — Fire Detector Replacement/Operability Test, Revision 0
- N2-FSP-FPL-M001 — CO_2 Valve Position Verification, Revision 1
- N2-FSP-FPP-R001 — Fire Rated Assemblies and Watertight Penetration Visual Inspection, Revision 2
- N2-FSP-FPW-R001 — Electric/Diesel Fire Pump Functional Test, Revision 5
- N2-OSP-FOF-W001 — Engine Driven Fire Pump Operability and Storage Tank Level Test, Revision 2
- S-FST-FPP-D001 — Daily Fire Door Inspection, Revision 1
- WO 97-2278-00 — Replace Security Batteries in Security Battery Room, Revision 0

M8 Miscellaneous Maintenance Issues (90712, 92700)

M8.1 <u>(Closed) LER 50-410/97-01: Technical Specification Violation Caused by Inadequate Response Time Testing of High Pressure Core Spray Actuation Instrumentation</u>

The LER described issues associated with the improper performance of TS required response time testing for the HPCS system. The technical details pertaining to theses issues were described in NRC IR 50-410/97-02. The LER was timely and satisfactorily described the issues. The inspectors reviewed the root cause and corrective actions provided in the LER and considered them to be appropriate.

III. ENGINEERING

E1 Conduct of Engineering (37551)

E1.1 General Comments

Using NRC Inspection Procedure 37551, the resident inspectors frequently reviewed design and system engineering activities and the support by the engineering organizations to plant activities. Specialist inspectors in this area used other procedures during their reviews of engineering activities; these inspection procedures are listed, as applicable, for the respective sections of the inspection report.

E1.2 Unit 1 Core Spray Containment Isolation Valves Susceptibility to Pressure Locking

a. Inspection Scope

The inspectors reviewed the licensee event notification to the NRC regarding the discovery of Unit 1 core spray (CS) outboard CIVs being susceptible to pressure locking during quarterly surveillance testing.

b. Observations and Findings

During a review of documents associated with the closure of the Unit 1 NRC Generic Letter (GL) 89-10 Program ("Safety-Related Motor-Operated Valve Testing and Surveillances"), NMPC design engineering discovered that their response to NRC GL 95-07 ("Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves") did not appropriately consider pressure locking concerns for CS outboard CIVs 40-02 and 40-12. Due to the use of a more conservative valve factor, the licensee identified that the valves were now considered susceptible to pressure locking. The inspectors determined the licensee's initial engineering evaluation in 1994 to be weak, in that the individuals who prepared, reviewed and approved the evaluations failed to recognize the potential for pressure locking during the quarterly surveillance test. Notwithstanding the earlier weakness, the inspectors considered the reevaluation and identification of this issue to be appropriate.

The outboard CIVs are normally deenergized in the open position, with their circuit breakers locked open, in accordance to TSs. However, during quarterly surveillance testing, the valves are closed to permit stroking of the inboard CIVs. The licensee determined that if a LOCA were to occur while in this configuration, the resulting pressure differential across the outboard CIV disc could prevent the valve from opening, as designed. Therefore, the licensee determined that the outboard CS CIVs had been potentially inoperable when performing the stroke test of the inboard CIVs during the surveillance test. Inoperability of the outboard CS CIV would have required entry into a one-hour shutdown LCO, as required by TS 3.1.4.d, which was never implemented; the licensee, however, never exceeded one hour while in this configuration.

During the forced outage discussed in Section O1.3, the licensee installed a thermal binding relief modification by establishing an equalizing path between the valve disc and the upstream piping. The installation of this modification during the forced outage was both prudent and appropriate.

c. Conclusions

Licensee identification of potential CS CIV pressure locking as a result of the use of a more conservative valve factor was appropriate; however, the initial evaluation in 1994 was weak in that NMPC failed to recognize the potential for pressure locking during the surveillance test. The licensee's effort to install the CS thermal relief modification during a forced outage was both prudent and appropriate.

E3 Engineering Procedures and Documentation (37551)

E3.1 Review of 10 CFR 50.59 Evaluations for Core Shroud Repair

The inspectors, with the assistance of NRR, reviewed the 10 CFR 50.59 safety evaluations (SEs), and related documents, associated with the engineering review of the Unit 1 core shroud vertical weld cracks and shroud tie-rod assemblies (see NRC IR 97-03, Section O1.5). The licensee's SEs, listed below, were reviewed by the SORC and approved between February 1995 and May 1997.

	Number	Safety Evaluation Repair	Revision	SORC Date
•	SE 94-080	Reactor Core Shroud Repair	00	2/9/95
			01	4/1/95
•	SE 95-007	Core Shroud Repair Installation	00	2/7/95
			01	9/3/96
			02	2/27/97
•	----	NRC Letter Documenting Core Shroud Stabilizer Design		3/31/95
•	SE 96-018	Modification to the Core Shroud Repair Tie-Rod Assemblies	00 01	8/14/96 4/11/97
•	----	RFO14 Core Shroud and Stabilizer Invessel Inspection Plan: NER-1M-029, R1		3/11/97
•	SE 97-101	Core Shroud Boat Sample Removal	00	4/11/97
•	SE 97-124	Core Shroud Vertical Weld Cracking, Cold Shutdown (Refueling and Major Maintenance)	00	4/17/97
•	SE 97-103	Installation of Modified Shroud Repair Latches Prior to NRC Approval of Adequacy Under 10 CFR 50.55a(a)(3)	00	4/26/97
•	97-025	Core Shroud Vertical Weld Cracking	01	5/3/97

The NRC review found the SEs to be acceptable. The information provided by the licensee in the above documents was used during the preparation of the related NRC Safety Evaluations Reports (SERs) issued March 31, 1995, and May 8, 1997.

E7 Quality Assurance in Engineering Activities (40500, 37551)

E7.1 Unit 2 Independent Safety Engineering Group Staffing

The inspectors reviewed the Unit 2 Independent Safety Engineering Group (ISEG) staffing over the last five years, including extended absences greater than two weeks, to verify that the staffing satisfied the TS requirements of five members. Five ISEG positions were in place during this entire period, and, in general, when ISEG members were temporarily assigned other duties, a qualified replacement was provided to ISEG. However, two cases were noted when ISEG members were absent for greater than two weeks but a replacement was not obtained. The first case was when an ISEG member attended system certification training for four months. In the second case, the ISEG Director participated in a peer evaluation at another facility for three weeks. Although training is a part of most job descriptions, and ISEG would directly benefit from these activities, the inspectors considered it less than prudent not to provide a replacement during these periods of extended absence.

E8 Miscellaneous Engineering Issues (90712, 92700, 929903)

E8.1 (Closed) LER 50-220/96-12-01: Missed Local Leak Rate Tests Caused by Personnel Error

a. Inspection Scope

The inspectors reviewed Supplement 1 to Unit 1 LER 96-12 and discussed two administrative issues with the Licensing Manager.

b. Observations and Findings

As a result of corrective actions associated with LER 50-220/96-12, discussed in NRC IR 50-220/97-01, Unit 1 engineering identified two additional CIVs in a configuration which affected previous 10 CFR 50, Appendix J, Type B leak rate tests. The specific valves were IV 201-08 and IV 201-16, the torus vent and purge isolation valves, respectively. The licensee noted a potential discrepancy relative to the CIVs, but could not confirm the discrepancy during a drawing review; subsequently, the valves were disassembled and inspected. During the evaluation of the as-found valve configuration, NMPC identified that the valve seals contained a steel seat retaining ring and a gasket, which were not on the design drawings.

Unit 1 TS surveillance requirement, Section 3.3.3.d, states that primary containment testable penetrations and isolation valves required to be Type B or Type C tested by regulatory requirements, shall be tested at a pressure of 35 pounds per square inch gage each major refueling outage, not to exceed two years.

The licensee determined that the as-found valve configuration, relative to the steel seat retaining ring and gasket, allowed a possible leak path not tested during Type B local leak rate tests. The torus vent and purge isolation valves were previously subjected to, and satisfactorily passed, Type A integrated leak rate testing. Therefore, Unit 1 engineering staff concluded that this configuration error did not affect containment integrity. However, the failure to identify and include the torus vent and purge isolation valves seat ring and gasket in the Appendix J program is a violation of TS, Section 3.3.3.d. This non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. **(NCV 50-220/97-04-07)**

The inspectors reviewed the LER supplement and determined it satisfactorily described the issue. The root cause evaluation, personnel failure to maintain plant configuration, and immediate and followup corrective actions to prevent recurrence appeared appropriate.

In addition, the inspectors discussed with the NMPC Licensing Manager the fact that the event report was not submitted until thirty-nine days after the event. The Licensing Manager stated that there was no adequate justification for the delay. Failure to submit the event report within thirty days is a violation of 10 CFR 50.73. This failure constitutes a violation of minor significance and is being treated as a Non-Cited Violation consistent with Section IV of the NRC Enforcement Policy. **(NCV 50-220/97-04-08)**

The inspectors also discussed with the Licensing Manager the NMPC practice of issuing an LER supplement, in lieu of a new LER, for related events. NUREG-1022, "Event Reporting Guidelines 10 CFR 50.72 and 50.73," Revision 1 (Second Draft), states that LER revisions [supplements] should be used "... only to provide additional or corrected information about a reported event ... not [to report] subsequent failures of the same or like component ... report events of this type as new LERs and not as revisions [supplements] to previous LERs." The inspectors discussed the issue with NRC headquarters staff in the Office for Analysis and Evaluation of Operational Data (AEOD). The AEOD staff concurred that a new LER should probably have been issued, and that good practice would be to issue a new LER if a related event occurred beyond thirty days of the original event. The initial LER was submitted in November 1996, while the discovery date of the subsequent event occurred in March 1997. In this instance, the inspectors considered the use of an LER supplement to be inconsistent with the guidance in NUREG-1022.

c. <u>Conclusions</u>

NMPC's failure to identify and include the torus vent and purge isolation valves seat ring and gasket in the Appendix J program allowed for an untested leakage path. (NCV) In addition, the event report was not submitted within thirty days as required by 10 CFR 50.73. (NCV) Also, the NMPC practice of issuing an LER supplement, in lieu of a new LER for a new event, does not appear to be consistent with the guidance in NUREG-1022.

E8.2 (Closed) LER 50-220/97-02: Shroud Repair Anomalies

On March 18, 1997, NMPC identified that one core shroud tie-rod repair assembly was degraded, and subsequent inspections revealed that the other assemblies had also experience some degradation. Specifically, all of the tie-rod assemblies had lost some vertical pre-load and three of the lower spring wedge latches were damaged. The details of the event were discussed in NRC IR 50-220/97-02, Section E2.1.

NMPC identified the apparent root cause of the tie-rod degradation to be incorrect design assumptions. Specifically, an incorrect assumption was made regarding the ability for the lower support wedge contact point to slide along the reactor pressure vessel wall, thus leading to unanticipated stress on the latches. The stresses resulted in latch failure through intergranular stress cracking corrosion.

The inspectors reviewed the LER and determined it satisfactorily described the issue. The root cause evaluation and immediate and followup corrective actions to prevent recurrence appeared appropriate. However, 10 CFR 50, Appendix B, Criterion III, "Design Control," states that measures shall be established for the selection and review for suitability of materials, parts, equipment, and processes that are essential to the safety-related functions of the structures, systems and components. Contrary to this, NMPC failed to recognize the potential for the latches to experience significant loading and stresses. This non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. **(NCV 50-220/97-04-09)**

E8.3 (Closed) VIO 50-410/96-07-01: ISEG Functions not Proceduralized

According to the Unit 2 UFSAR, Section 1.10, ISEG was established as required by NUREG-0737, "Clarification of TMI [Three Mile Island] Action Plan Requirements." TS 6.8.1.b requires that written procedures be established to implement the requirements of NUREG-0737. Prior to March 22, 1996, procedures were not established to implement ISEG activities. The licensee provided the root cause and corrective actions for the violation in their November 15, 1996, response to the NRC. The corrective actions included the development of Procedure N2-NSAS-IAP-0101, "Independent Safety Engineering Group Program Implementation Directive," and the review of other activities to assure that appropriate procedures existed for the activities listed in 6.8.1 and that appropriate controls to ensure that the review and approval requirements of TS 6.8.2 for those procedures were completed.

The inspectors reviewed Procedure N2-NSAS-IAP-0101, effective November 15, 1996, and determined that it reflected the applicable portions of the TS, UFSAR, and NUREG-0737. In addition, the inspectors assessed the results of the licensee review of other activities associated with TS 6.8.1. The inspectors considered the review to be comprehensive, and the discrepancies identified by the licensee during this review were being address through the DER process. Based on the inspectors' review, Violation 50-410/96-07-01 is closed.

E8.4 (Closed) LERs 50-410/97-02 and 50-410/97-02-01: Potential Inoperability of Emergency Diesel Generator Service Water Cooling Water Outlet Valves During a Control Room Fire

The LER, and supplement, described issues associated with electrical circuits at the remote shutdown panel (RSP) which were inadequately isolated such that a fire within the control room could have disabled the functions from the RSP. In particular, LER 50-410/97-02 described concerns associated with control circuits at the RSP for Division I and II EDG cooling water outlet valves not being isolated from the control room. Therefore, a fire-induced short circuit would disable operation of these valves from the RSP. Supplement 1 to LER 97-02 described concerns associated with electrical circuits at the RSP for the valve position indication (VPI) for the "A" and "B" RHR pump minimum flow valves. Therefore, a fire-induced short circuit would disable the VPI from the RSP. A loss of the RHR minimum flow VPI at the RSP would inhibit the operator's ability to complete the remote shutdown procedure, and thus place and maintain the reactor in a safe shutdown condition. The technical details associated with the above two issues are contained in NRC IR 50-410/97-05. The LER and supplement were timely and satisfactorily described the events. The inspectors reviewed the root cause and corrective actions provided in the LERs and considered them to be appropriate.

During their review, the inspectors noted that another event associated with the Division I EDG cooling water outlet valves not being isolated from the control room was not described in either LER submittal, nor was a separated LER issued to described the event. On April 11, 1997, the licensee notified NRC, in accordance with 10 CFR 50.72, about a condition of the plant being outside the design basis. The technical details regarding this event are described in NRC IR 50-410/97-05. The inspectors reviewed the associated DER (2-97-1136) and discussed the missed LER submittal with the Licensing Manager, members of the licensing staff, and with the Unit 2 Operations Manager. The information gain by the inspectors through these discussions was inconsistent, particularly with respect to whether the April 11 event was or was not a condition outside the design basis, and therefore, whether or not reportable under 10 CFR 50.73. The inspectors were unable to obtain documentation to substantiate the licensee's position that the event was not outside the design basis of the plant; but DER 2-97-1136 indicated that the event was discussed in LER 50-410/97-02. The licensee did indicate to the inspectors that the root cause and corrective action described in LER 50-410/97-02 for the April 7 event would be the same for the April 11 event.

Based on the inspectors' review, this item is unresolved pending NRC review of the licensee's basis for the event on April 11, 1997, not being considered a condition outside the design bases of the plant, and review of the statement in DER 2-97-1136 indicating that the April 11 event was described in LER 50-410/97-02. **(URI 50-410/97-04-10)**

E8.5 (Closed) LER 50-220/97-05: Potential Pressure Locking of Core Spray Valves During Surveillance Testing

The event was discussed in Section E1.2 of this inspection report. The description in the LER was consistent with the inspectors' understanding of the event, and the root cause analysis and corrective actions appear appropriate. This LER is closed.

IV. PLANT SUPPORT

Using NRC Inspection Procedure 71750, the resident inspectors routinely monitored the performance of activities related to the areas of radiological controls, chemistry, emergency preparedness, security, and fire protection. Minor deficiencies were discussed with the appropriate management, significant observations are detailed below. Specialist inspectors in the same areas used other procedures during their reviews of plant support activities; these inspection procedures are listed, as applicable, for the respective sections of the inspection report.

R8 Miscellaneous RP&C Issues (71750)

R8.1 Remote Monitoring of High Radiation Areas at Unit 1

a. Inspection Scope

The inspectors discussed with Unit 1 radiation protection (RP) staff and operations staff and management the recent installation of additional monitors located in high radiation areas (HRA) to reduce personnel dose as part of the as-low-as-is-reasonably-achievable (ALARA) program.

b. Observations and Findings

The Unit 1 RP staff provided the inspectors with a tour and demonstration of cameras and monitors installed in Unit 1 during the recent refueling outage. Remote cameras with monitoring capability had previously been installed in some areas. The new cameras were installed in high radiation dose rate areas frequently toured by operations personnel. The cameras provided the operators with the ability to reduce their time in these spaces and lower their overall accumulated dose. The inspectors considered installation of the cameras a good ALARA application.

Eighteen cameras were installed in the bays (enclosures) housing the three feedwater heater trains, allowing operators to visually inspect all six levels of the feedwater heater bays. The remote monitor for these cameras was located on the 291-foot elevation of the turbine building. Additional cameras were mounted in the condenser bay, positioned to monitor the condensate pumps, the main turbine stop and bypass valves, the moisture separators and reheater drains, and the turbine controls. A separate monitor for these cameras was located on the 277-foot elevation of the turbine building.

The inspectors considered the visual clarity and coverage provided by these cameras to be very good. Additionally, the inspectors discussed with the Operations Manager how the cameras would affect operator tours and logkeeping. The Operations Manager noted that the cameras were not a substitute for normal operator rounds, and that operators were still required to conduct tours in these areas. Independent inspector discussions with operators confirmed this expectation. A specific benefit of the cameras was the ability to monitor and trend a degraded component (e.g. packing leak) without having to frequently enter the space, thus reducing overall radiological dose. This ability to continuously monitor certain degraded equipment in HRAs could prove a significant ALARA benefit.

c. Conclusions

Installation of remote monitoring cameras in frequently toured HRAs was a good ALARA application, and the ability to continuously monitor certain degraded equipment in HRAs could prove a significant ALARA benefit.

P4 Staff Knowledge and Performance in Emergency Preparedness (71750)

P4.1 Unit 2 Simulator Observations During Emergency Preparedness Drill

a. Inspection Scope

The inspectors monitored the performance of a Unit 2 control room crew during an emergency preparedness (EP) training drill.

b. Observations and Findings

On June 12, 1997, the inspectors observed the performance of a shift crew in the Unit 2 simulator control room during an EP training drill. The drill started with the plant operating at 100% power and several major systems out-of-service. The scenario included:

- Tampering of a key lock switch for the Appendix R feedpump disconnects -- resulting in the declaration of an Unusual Event;
- Fire in the relay room -- resulting in the declaration of an Alert;
- Loss of instrument air causing a lowering scram air header pressure, a manual scram followed by an anticipated transient without a scram (ATWS) and associated fuel damage and a leak into the drywell -- resulting in the declaration of a Site Area Emergency; and
- One division of electrical power is lost accompanied by an unisolable steam leak and elevated radiation levels -- resulting in the declaration of a General Emergency.

The inspectors considered the performance by the Unit 2 operators to be generally good. Minor weaknesses noted were discussed with the EP drill coordinator and the Unit 2 Plant Manager.

c. Conclusion

The performance of a Unit 2 control room shift crew in the simulator during an EP drill was considered good.

S2 Status of Security Facilities and Equipment (71750)

S2.1 Unit 2 Refuel Floor Access Gate Found Unsecured

a. Inspection Scope

During a routing tour, the inspectors found the access gate on the Unit 2 refuel floor improperly secured. The inspectors informed the Unit 2 SSS and the NMPC Security Supervisor.

b. Observations and Findings

On June 17, 1997, during a routine tour of the Unit 2 reactor building, the inspectors identified that the access gate (number R353-1) from the elevator to the refuel floor was not properly secured. The gate is comprised of two sections; one section is supposed to be secured in place by lockable upper and lower bolts, the other section would normally be opened by use of the security card (ACAD) reader. In this case, the inspector noted that the lower surface bolt was not inserted into the floor. Further investigation identified that the upper bolt was unlocked and could have been lowered by reaching through the gate.

While maintaining visual observation of the gate, the inspector contacted the Unit 2 control room and the NMPC Security Supervisor. Immediate corrective action included performance of security maintenance Procedure S-SMP-SD to lock the surface bolts on the gate. In addition, a DER (2-97-1806) was initiated to determine the significance, root cause, and necessary corrective actions for recurrence control. Pending NMPC's disposition of the DER, and NRC review of the completed DER, this item will remain unresolved. **(URI 50-410/97-04-11)**

c. Conclusion

During a routine tour of the Unit 2 reactor building, NRC inspectors found the access gate to the refuel floor unlocked. (URI)

F1 Control of Fire Protection Activities (64704)

F1.1 Fire Risk Evolutions

a. Inspection Scope

The inspectors reviewed the NMPC administrative processes for controlling and evaluating fire hazards, including limiting the interaction of combustible and flammable materials with ignition sources. This review was conducted to verify

that adequate guidance and proper authorization requirements existed for identifying and limiting fire risk.

b. Observations and Findings

The inspectors found that the administrative process for controlling ignition sources included the use of a permit system for authorization to perform hot-work activities. This authorization form was approved by the NMPC Fire Chief and the respective SSS. The inspector found that the process included an evaluation by the Fire Chief of the need to direct fire protection personnel to inspect hot work areas to identify any potential fire protection problems and to ensure that any need for additional firewatches was provided appropriately. The inspectors determined that the established process provided for a comprehensive review of fire areas to identify any potential interaction of combustible and flammable materials with ignition sources.

c. Conclusion

The inspectors determined that good administrative controls had been established for proper storage of combustibles in the plant and for the control of hot-work.

F2 Status of Fire Protection Facilities and Equipment (64704)

F2.1 Facility Tour

a. Inspection Scope

The inspectors toured accessible vital and non-vital areas of the site and inspected the fire protection water suppression systems, fire pumps, piping and distribution systems, post indicator valves, contents of indoor fire protection storage facilities and outdoor hose houses, emergency lighting patterns for access and egress routes for selected safety-related plant equipment areas, and the condition of fire brigade (FB) equipment.

b. Observations and Findings

The inspectors found that fire protection equipment material conditions were good and fire-loading was properly maintained in those areas selected for review. FB members' protective clothing and gear were found in good condition and were adequately organized in the brigade lockers throughout both units.

The inspectors determined that the housekeeping conditions in plant areas containing safety-related equipment or components were good. No examples were noted involving the improper control of combustibles.

Regarding emergency lights, the inspectors found that recent actions had been implemented to improve the effectiveness of emergency lights and resolve deficiencies identified by the licensee. (Initially discussed in NRC IR 50-220/97-03,

Section F2.2, at which time an NCV was issued.) These deficiencies included the failure of emergency lights to remain illuminated for an eight hour duration as required by 10 CFR Part 50, Appendix R, Section III.J. The inspectors noted 49 of 172 emergency light failures for Unit 1 and 55 of 310 emergency light failures for Unit 2. The following licensee DERs describe the light failures: 1-95-3027, 1-97-1378, 1-97-1284, and 2-97-1602.

NMPC determined that the reason for the high failure rate of emergency lights (28.5% for Unit 1 and 18% for Unit 2) was that in-service testing and maintenance was inadequate to detect excessive degradation of the lighting units. The apparent cause for this inadequacy was that the vendor-recommended testing did not confirm the ability of the batteries to perform their intended safety function to operate for an 8-hour duration. Following receipt of vendor information in April 1990 (reference Exide vendor manual N1077 and letter SM-CS90-0136), NMPC reduced the discharge test duration for emergency lights from 8 hours to 90 minutes in the annual surveillance procedures N1-FPM-LOG-A001 and N2-FPM-LOG-A001, Revision 2, "Battery Emergency Light Eight Hour Test." This reduction in test duration was incorporated into the surveillance procedures in May 1990.

Although the testing for the emergency lights was determined to be inadequate because of the identified high failure rate, the inspectors noted that portable lights were maintained appropriately as compensatory measures for operators per procedure EPMP-EPP-02, "Emergency Equipment Inventories and Checklists," Revision 0. Corrective actions taken by the licensee in April 1997, included changing the surveillance test duration for the lights back to 8 hours, and the development of a plan to ensure fixed 8-hour battery-powered emergency lights would be provided for all plant areas needed by operators for safe plant shutdown and access and egress pathways, per special operating and damage repair procedures, including N2-OP-78, "Remote Shutdown System," Revision 10, and N2-SOP-78, "Control Room Evacuation," Revision 1. This plan included the replacement of several battery pack supplies for the lights, development and implementation of a preventive maintenance procedure for battery replacement, and a procedure for verifying proper lamp head alignment.

Although adequate compensatory measures had been maintained by NMPC while emergency lights were out of service, the inspectors determined that the acceptance of the vendor's recommendation for reduced testing without additional engineering review to verify the adequacy of this testing change was a weakness in the surveillance program. In addition, the inspectors noted that the licensee's failure to establish a preventive maintenance procedure for battery replacement of emergency lights was also a weakness of the preventative maintenance, that contributed to the failure to provide good assurance that the lights would remain operable for 8 hours.

c. Conclusions

The inspectors concluded that fire protection equipment conditions and housekeeping were good. Recent initiatives taken by NMPC to improve emergency

lighting were appropriate, despite past weaknesses for adequately testing emergency lights and assuring their functionality for an 8-hour duration.

F4 Fire Protection Staff Knowledge and Performance (64704)

F4.1 Fire Brigade Drills

a. Inspection Scope

The inspectors observed an unannounced fire drill to evaluate the effectiveness of the FB and their understanding of fire attack strategies. The drill was conducted to demonstrate the following:

- an understanding of the fire attack strategy;
- the ability to assess the fire properly;
- an awareness of vital equipment in the area;
- effective communication with other FB members; and
- an awareness of additional hazards in the fire area.

b. Observations and Findings

The inspectors observed a fire drill on June 5, 1997. A fire was simulated on the Unit 1 #102 EDG following an unsuccessful carbon dioxide room release. The inspectors determined, based on drill observations and post-drill discussions with responding brigade members, that the performance and knowledge of the drill participants was very good. This determination of acceptability was based on the following:

- use of an appropriate suppressant type on the fire;
- command and control demonstrated by the FB leader;
- teamwork displayed by FB members; and
- communications among brigade members.

The inspectors found the quality of the critique following the drill to be effective; in that, it provided constructive feedback to the FB regarding performance. Although the FB's performance was found by the inspectors to be very good for the particular drill scenario observed, the inspectors made the following two observations:

- The briefing and props provided by the training specialist for this drill were minimal and failed to provide good simulated fire scene conditions. This failure to provide information could inhibit drill participants from fully benefiting from a drill exercise. Without a good appreciation of the fire conditions, drill participants cannot appropriately evaluate the fire scene nor subsequently develop individual action plans for extinguishing the fire.

- Although it was well understood by all drill participants, and the inspectors, where the Fire Chief's command post would most likely be established and how the attack strategy would be implemented, the inspectors noted that for

most other possible fire scenarios, it would be prudent for the Fire Chief to make brigade assignments following initial evaluation of the fire following arrival at the fire scene.

The training instructor noted the inspectors' observations as areas for improvement and additional consideration. The Training Specialist stated his intentions for further improving the effectiveness of brigade drills.

The inspectors noted the implementation of the licensee's "Walkdown Program," where FB members walkdown the unit that they are not normally assigned to. This program was designed to increase brigade members' familiarity for enhancing the awareness of plant layout and design. The inspectors found this program to be a very good initiative.

c. Conclusion

The inspectors determined that the performance of the FB during the drill was very good. The inspectors found the implementation of the licensee's program for increasing brigade members familiarity with the plants to be prudent and a very good initiative.

F5 Fire Protection Staff Training and Qualification (64704, 71750)

F5.1 Fire Brigade Training

a. Inspection Scope

The inspectors reviewed the training program requirements, the training provided for FB members to verify that members had completed all required training for qualification and duty, and the level of detail of training considering the composition of the fire brigade. Additionally, the inspectors observed live fire school training.

b. Observations and Findings

Training Program and Qualification

The inspectors verified that six FB members selected for review had successfully completed the required training courses, drills, and respirator training and passed their annual medical physicals. The inspectors reviewed the records contained in the TRAIN (Training Records and Information Network) computer database and found them to be complete and easily retrievable. No deficiencies were identified.

The inspectors observed annual live fire training provided to four radioactive waste (radwaste) operators at the Nine Mile Point fire training facility. The inspectors found the lesson material and associated discussions provided during the classroom portion of the training to be well-organized and complete. During the hands-on portion, the four FB members appropriately donned brigade gear and used fire hoses

to extinguish live fires. The inspectors concluded that the live training provided to FB members was very good, and satisfactorily prepared them to combat fires.

The inspectors found that the initial and continuing training programs appropriately placed emphasis on potential fire hazards and cautionary measures, supported brigade member readiness, and complied with NRC requirements and the Nine Mile Point licensing basis, as presented in the UFSAR for each unit.

Fire Brigade Composition and Level of Training

The FB is comprised of personnel from the Nine Mile Point fire department and radwaste operators from both units. Due to the diverse makeup of the brigade, the inspectors interviewed FB members to determine if the training was commensurate with their individual fire fighting background. The level of technical training was considered adequate for both radwaste operators and fire department personnel.

During the interviews, several concerns were presented to the inspectors; most of which had already been discussed internally with NMPC management. Of specific interest was a comment, in February 1997 timeframe, that one of the FB instructors was supposedly telling the FB members to not to talk with the NRC during a planned (May 1997) inspection. The words used by the instructor were to the effect "... during the NRC inspection would not be a good time to bring up concerns regarding the fire protection program." Further review by the NRC, including interviews with both instructors, determined that one or both of the instructors may have made a comment similar to the above, but as part of a broader message. Although poorly communicated, the intended message was basically:

> If there is a valid safety concern, don't wait until May to identify it to someone. If there are safety concerns, and the FB members did not want to use their management or the NMPC Quality First Program (Q1P), then the NRC was an option that was endorsed by NMPC.

The inspectors considered the explanations acceptable. In addition, after the NRC review was complete, NMPC conducted their own review and came to the same conclusion. The inspectors had no further questions.

c. Conclusions

The inspectors concluded that the licensee's training program provided for fire brigade members was well-organized and complete, and complied with NRC requirements for preparing fire brigade members to combat fires. The level of detail contained in the training was considered adequate for both the fire department personnel and the radwaste operators.

F7 Quality Assurance in Fire Protection Activities (64704)

F7.1 Audits and Surveillances

a. Inspection Scope

The inspector reviewed the audit reports completed to satisfy the technical specification requirements that evaluated the effectiveness of fire protection measures, equipment, program implementation, and problem identification and resolution.

b. Observations and Findings

The inspector reviewed the three most audits reports and determined that they demonstrated good problem identification, had been appropriately completed, and clearly communicated findings in reports. The reports reviewed were:

- Audit Report No. 96019 -- Fire Protection Program Review (1996)
- Audit Report No. 95015 -- Fire Protection Program Review (1995)
- Audit Report No. 94027 -- Annual Fire Protection SRAB Audit (1994)

c. Conclusion

The inspector concluded that QA audits focused appropriately on and verified selected fire program attributes for compliance with program requirements.

F8 Miscellaneous Fire Protection Issues (92904)

F8.1 (Closed) LER 50-220/97-04: 10 CFR 50, Appendix R, Section III.J, Lighting Deficiencies

The technical details associated with the issue described in this LER were described in NRC IR 50-220/97-03, Section F2.2. The event description, root cause analysis, and corrective actions, as delineated in the LER, are consistent with the inspectors review of the event.

F8.2 Documents Reviewed During Fire Protection Program Inspection

- EPIP-EPP-28 Fire Fighting, Revision 3
- GAP-FPP-02 Control of Hotwork, Revision 2 and 5
- GAP-HSC-01 Housekeeping, Tours, and Inspections, Revision 3
- GAP-INV-02 Control Of Material Storage Areas, Revision 2
- NDD-FPP Fire Protection Program, Revision 3
- NEP-DES-05 Design Input, Revision 1
- NEP-DES-06 Design Impact Checklist, Revision 3
- NEP-FPP-01 Fire Protection Engineering, Revision 1
- NIP-FPP-01 Fire Protection Program, Revision 6
- NIP-TQS-01 Qualification Of Firewatches, Revision 2

∘	NTP-TQS-402	Fire Brigade Training Program, Revision 6
∘	N2-SOP-78	Control Room Evacuation, Revision 1
∘	N2-OP-78	Remote Shutdown System, Revision 0
∘	S-SAD-FPP-0105	Compensatory Measures For Inoperable Fire Detection Systems And Components, Revision 0

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 exit meetings for specialist inspections were conducted upon completion of their onsite inspection:

- Unit 1 License Operator Requalification Program — May 30
- Fire Protection Program — June 6

The final exit meeting occurred on July 18, 1997. During this meeting, the resident inspector findings were presented. NMPC did not dispute any of the inspectors findings or conclusions. 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.

ATTACHMENT 1

PARTIAL LIST OF PERSONS CONTACTED

Niagara Mohawk Power Corporation

R. Abbott, Vice President & General Manager - Nuclear Generation
D. Barcomb, Radiation Protection Manager, Unit 2
C. Beckham, Manager, Quality Assurance
D. Bosnic, Operations Manager, Unit 2
J. Burton, Director, ISEG
H. Christensen, Security Manager
J. Conway, Vice President - Nuclear Engineering
G. Correll, Chemistry Manager, Unit 1
A. DeGracia, Work Control Manager, Unit 1
S. Doty, Maintenance Manager, Unit 1
K. Dahlberg, Vice President - Nuclear Operations
R. Dean, Engineering Manager, Unit 2
G. Helker, Work Control Manager, Unit 2
M. McCormick, Vice President - Nuclear Special Projects
L. Pisano, Maintenance Manager, Unit 2
P. Smalley, Radiation Protection Manager, Unit 1
R. Smith, Operations Manager, Unit 1
K. Sweet, Technical Support Manager, Unit 1
C. Terry, Vice President - Nuclear Safety Assessment & Support
R. Tessier, Training Manager
K. Ward, Technical Support Manager, Unit 2
C. Ware, Chemistry Manager, Unit 2
D. Wolniak, Licensing Manager
W. Yaeger, Engineering Manager, Unit 1

INSPECTION PROCEDURES USED

IP 37551:	On-Site Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observation
IP 64704:	Fire Protection Program
IP 71001:	Licensed Operator Requalification Program Evaluation
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 92903:	Followup - Engineering
IP 92904:	Followup - Plant Support

ITEMS OPENED, CLOSED, AND UPDATED

OPENED

50-410/97-04-03	URI	Contrary to 10CFR50.59: Inadequate Remote Shutdown Procedure. Pending resolution of similar issues in NRC IR 97-05
50-220/97-04-04	IFI	Low difficulty level for Unit 1 written exams for licensed operator requalification training
50-220/97-04-05	IFI	Poor reliability of RPIS in simulator and control room; no procedure guidance to ensure reactor is shutdown under all conditions
50-220 & 50-410/97-04-06	URI	No SORC reviews of TS, Section 6.0 (administrative) violations; pending NRR review
50-410/97-04-10	URI	Basis for not submitting an LER for a reported condition outside of design basis
50-410/97-04-11	URI	Refueling floor gate not properly locked

CLOSED

50-410/96-07-01	VIO	Contrary to TS 6.8.1: ISEG functions not proceduralized
50-410/97-04-01	NCV	Contrary to TS 6.8.1: failure to properly implement RWCU backwash procedure, resulting in ESF actuation
50-220/97-04-02	NCV	Contrary to 10CFR50, Appendix B, Criterion V: EDG plant configuration not consistent with P&ID
50-220/97-04-07	NCV	Contrary to TS 3.3.3.d: failure to identify and include torus isolation valves seat ring and gasket leak path in Appendix J program
50-220/97-04-08	NCV	Contrary to 10CFR50.73: failure to submit an event report within 30 days
50-220/97-04-09	NCV	Contrary to 10CFR50, Appendix B, Criterion III: failure to adequately design the lower latch assembly for the shroud tie-rod
50-220/96-11	LER	Reactor scram caused by the main generator lockout relay trip
50-220/96-12-01	LER	Missed local leak rate test caused by personnel error
50-410/97-01	LER	Technical specification violation caused by inadequate response time testing of high pressure core spray actuation instrumentation
50-220/97-02	LER	Shroud repair anomalies
50-410/97-02	LER	Potential inoperability of emergency diesel generator service water cooling water outlet valves during a control room fire
50-410/97-02-01	LER	Potential inoperability of emergency diesel generator service water cooling water outlet valves during a control room fire

50-220/97-04	LER	10CFR50, Appendix R, Section III.J, lighting deficiencies
50-410/97-04	LER	Reactor water cleanup isolation on high differential flow caused by personnel error
50-220/97-05	LER	Potential pressure locking of core spray valves during surveillance testing
50-220/97-06	LER	Technical specification required shutdown because of loss of reactor coolant system leakage monitoring ability

UPDATED

none

LIST OF ACRONYMS USED

AEOD	Analysis & Evaluation of Operational Data
ALARA	As Low As Reasonably Achievable
ASC	Alternate Shutdown Cooling
ASSS	Assistant Station Shift Supervisor
CFR	Code of Federal Regulations
CIV	Containment Isolation Valve
CS	Core Spray
CSO	Chief Station Operator
DER	Deviation/Event Report
DWFD	Drywell Floor Drain
EDG	Emergency Diesel Generator
EP	Emergency Preparedness
ESF	Engineered Safety Feature
FB	Fire Brigade
GE	General Electric
GL	Generic Letter
gpm	gallons per minute
HPCS	High Pressure Core Spray
HRA	High Radiation Area
IFI	Inspector Follow Item
IR	Inspection Report
ISEG	Independent Safety Engineering Group
IST	Inservice Testing
JPM	Job Performance Measure
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
LORT	Licensed Operator Requalification Training
NCV	Non-Cited Violation
NMPC	Niagara Mohawk Power Corporation
NRC	Nuclear Regulatory Commission

P&ID	Piping and Instrumentation Diagram
PB	Power Board
QA	Quality Assurance
RG	Regulatory Guide
RHR	Residual Heat Removal
RO	Reactor Operator
RPIS	Rod Position Indicating System
RWCU	Reactor Water Clean-Up
SAT	Systems Approach to Training
SE	Safety Evaluation
SIL	Service Information Letter
SOP	Special Operating Procedure
SORC	Station Operations Review Committee
SRO	Senior Reactor Operator
SRV	Safety Relief Valve
SSS	Station Shift Supervisor
STA	Shift Technical Advisor
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
USQ	Unreviewed Safety Question
VIO	Violation
WO	Work Order

[illegible]