U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Report Nos.:	96-01 96-01
Docket Nos.:	50-220 50-410
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:	January 7 - February 17, 1996
Inspectors:	B. S. Norris, Senior Resident Inspector M. J. Buckley, Resident Inspector R. A. Skokowski, Resident Inspector
Approved by:	Richard J. Conte 4/22/96 Richard J. Conte, Chief — Date Projects Branch 5 Division of Reactor Projects
Areas Inspected:	see Executive Summary

9604290268 960422
PDR ADOCK 05000220
Q PDR

EXECUTIVE SUMMARY

Nine Mile Point Units 1 and 2
50-220/96-01 & 50-410/96-01
January 7 - February 17, 1996

SAFETY ASSESSMENT/QUALITY VERIFICATION

Unit 2 licensee event report (LER) 95-12, which described snow plugging of the inlet filters of the reactor building ventilation system, and automatic initiation of the standby gas treatment system, only addressed corrective actions to prevent snow from clogging the inlet filters. However, Niagara Mohawk Power Corporation (NMPC) stated in the LER that the root cause of the event was inadequate corrective actions for similar problems in the 1980's. Although corrective actions were taken to address the root cause of inadequate corrective actions through the development of licensee's current deviation/event report (DER) process, this LER remains open pending the submittal of a Supplemental LER from NMPC that describes the corrective actions to address the stated root cause.

During the inspection period, the inspectors reviewed portions of the Updated Final Safety Analysis Reports (UFSAR) for the applicable unit and found them consistent with the observed plant practices, procedures, and parameters.

PLANT OPERATIONS

During the inspection period, both units maintained essentially full power. The inspectors observed good communications amongst the operators, and that operations management was frequently in both control rooms. While accompanying Unit 2 auxiliary operators on rounds, the inspectors noted that they demonstrated an appropriate awareness of plant conditions with a good questioning attitude.

Both units have been mostly successful in achieving and maintaining a "blackboard" philosophy of operations for the main control board annunciators. However, in Unit 2, the inspectors noted that several back-panel Rosemont trip units (RTU) were in a tripped condition, while the associated parameter indicated normal. (URI 50-410/96-01-01)

The reactor water cleanup (RWCU) system was overpressurized during post-maintenance restoration. The inspectors review found the operability and reportability determinations completed by NMPC to be appropriate. This item will remain unresolved pending NRC staff's review of NMPC determination of the root cause, corrective actions to prevent recurrence, and a review for similar events. (URI 50-410/96-01-02)

While at 100% power, a Unit 1 reactor feedwater pump tripped unexpectedly and the associated annunciator did not alarm. The quick actions taken by the operators prevented a reactor scram. NMPC determined that the pump trip and the failed annunciator were caused by two different Agastat relays, that failed due to heat and age. The inspectors noted that the specific relay used to initiate the annunciator alarm is never tested to ensure continued

operability. The lack of preventive maintenance and calibration of the annunciator relay reflected poor human factors attention, since a feedwater pump trip would not provide operators immediate notification of the problem. This will remain unresolved. (URI 50-220/96-01-03)

Normal work week schedule for personnel who perform safety-related activities remains unresolved awaiting final resolution by NMPC and further review by the NRC staff. (URI 50-220/96-01-04 & 50-410/96-01-04)

MAINTENANCE

The inspectors identified a yellow holdout tag on a drywell cooling water isolation valve listed the required position of "as-is." The use of this term is a poor practice that could lead to a component being unintentionally mispositioned. Unit 1 management agreed, and stated they would review the use the term.

An operator identified a chromate leak on the Unit 1 #102 emergency diesel generator, indicative of a cooler tube leak. The inspectors monitored the repairs and considered the activity well controlled, with frequent supervisor oversight.

During maintenance on a Unit 2 residual heat removal system valve, technical personnel noticed that the stub shaft was not rotating as expected, the cause was determined to be a failed dowel pin. During post maintenance testing, the valve was over-torqued by about 5.5%, due to an incorrect adjustment of the torque switch. An evaluation determined there was no significant valve damage, and that the valve was operable.

Unit 2 recently implemented a trial maintenance program called Fix-It-Now; commonly referred to as the FIN team. All FIN team members were knowledgeable of their responsibilities and very positive about the accomplishments to date. The inspectors confirmed that the activities of the FIN team are consistent with the normal requirements of the maintenance department. The inspectors considered the FIN team to be significant step towards controlling the daily maintenance work load and reducing the maintenance backlog.

The inspectors monitored the repairs for a packing leak on a Unit 2 reactor core isolation cooling (RCIC) system steam supply; the inspectors identified no maintenance related concerns during this review. The inspectors also observed the maintenance of the Unit 1 reactor feedwater pump, after it tripped, and the associated annunciator failed to alarm. The inspectors considered the efforts of all disciplines to be very good.

Unit 2 Technical Specification Interpretation #49 regarding remote shutdown instrumentation Limiting Conditions for Operations (LCO) 3.3.7.4 and RCIC LCO 3.7.4 was found to be weak in clarifying and integrating the safety and design objectives in the interpretation for entering the respective LCOs.

Executive Summary

ENGINEERING

The manufacturer of the Unit 2 Cooper Bessemer emergency diesel generators (EDGs) issued a 10 CFR Part 21 report regarding a potential design defect. NMPC initiated a DER to track the completion of the recommended inspections, the day before the 10 CFR Part 21 was issued. The inspectors considered NMPC's actions both appropriate and timely.

During a review of the Unit 2 Temporary Modification (TM) log, the inspectors noted a planned Furmanite repair to a leak on a feedwater heater flange. This flange had been previously repaired using a Furmanite compound. NMPC was able to tighten the flange and stop the leak, avoiding the need to perform the TM. The continued emphasis to stop the leak, as opposed to a repeated Furmanite application, was an indication of a good awareness of industry operational experience.

The inspectors noted that a temporary modification was installed on the Unit 2 circulating water system prior to the completion of the required safety evaluation. Further review identified that the NMPC procedure for temporary modifications allows for the installation if emergency temporary modifications before the completion of the required 10 CFR 50.59 safety evaluation; not to be confused with the ability to deviate to protect the public health and safety, as allowed by 10 CFR 50.54, Parts X and Y. The temporary modification procedure is applicable to both Units. Emergency temporary modification #96-002 was installed on January 31, 1996; the 10 CFR 50.59 safety evaluation was completed on February 2. The inspectors' review found the emergency temporary modification and the safety evaluation to be appropriate, with the exception of the failure to complete the required safety evaluation prior to the installation of the modification. The failure of NMPC to ensure the completion of the required safety evaluation prior to installation of changes to the facility, as described in the UFSAR, is a violation of 10 CFR 50.59. (VIO 50-220/96-01-05 & 50-410/96-01-05)

TABLE OF CONTENTS

RESIDENT INSPECTION DETAILS

1.0 SUMMARY OF ACTIVITIES

Niagara Mohawk Power Corporation (NMPC) Activities

During this inspection period, Nine Mile Point Unit 1 (Unit 1) and Unit 2 operated at essentially full power, with only minor reductions in power for maintenance and testing.

NRC Staff Activities

The NRC conducted inspection activities during normal, backshift, and weekend hours. Specialist inspections conducted during this period included physical security and engineering. The results of the security inspection are contained in NRC Inspection Report 50-220 & 50-410/96-03, issued under a separate letter. The engineering inspection was conducted near the end of the period and the results will be included in the next resident inspectors report.

2.0 PLANT OPERATIONS (71707, 92901, 93702)*

2.1 Operational Safety Verification

The inspectors observed overall operation and verified selectively that NMPC operated the units safely and in accordance with their procedures, license, and Technical Specifications (TSs). The inspectors conducted regular tours of all accessible plant areas. The tours included walkdowns of safety systems and components for leakage, lubrication, cooling, and general material conditions that might affect safe system operation. No significant deficiencies were noted, minor deficiencies were discussed with the appropriate management.

During shift turnovers at both units, the inspectors consistently observed good communications between the shift management and the operating staff. Operations management was frequently observed in both control rooms. The inspectors determined that the operators' performance was consistent with applicable NMPC procedures.

The inspectors accompanied Unit 2 auxiliary operators on rounds of the screenwell building, the control building, the switchgear building, and the switchyard. The operators demonstrated an appropriate awareness of plant conditions and a good questioning attitude, as evidenced by their identification and logging of deficiencies.

2.2 Control Room Checklists

The inspectors conducted extensive walkdowns of the control rooms of both units while developing detailed control room checklists. The checklists are a tool for the NRC inspectors to aid in the verification of important parameter

---

* The NRC inspection manual procedure or temporary instruction that was used as inspection guidance is listed for each applicable report section.

and equipment lineups. During the development of the checklists, the inspectors reviewed selected portions of the TSs, NMPC procedures related to daily and shiftly checks used by the control room operators, and portions of the emergency operating procedures.

The inspectors reviewed the daily and shiftly check procedures used by the operators and identified no concerns related to the adequacy of the TS requirements being reflected in the procedures. However, the inspectors did note that the line item description on the Unit 2 control room checklist did not match the description on the panel switch labels. This checklist is contained in the Procedure N2-ODP-OPS-0107, " Shift Turnover Guidelines," and is utilized by the operators during the shift relief process as an aid to verifying that equipment lineups are correct; the checklist is not used for the repositioning of switches. Through discussion with several operators and Unit 2 Operations Department Management, the inspectors found the operators' training and knowledge level of the plant equipment appropriate to ensure understanding of the checklist.

The site promotes a "blackboard" philosophy of operations; i.e., normal operating conditions are indicated by having no annunciators illuminated. Both units have been relatively successful in achieving and maintaining a blackboard for the main control board annunciators. However, in Unit 2, the inspectors questioned the control room operators about a back-panel Rosemont trip unit (RTU) that was in a tripped condition, while the associated parameter was within the normally expected band. Specifically, for the low pressure core spray pump, RTU E21-N656, "Fill Pmp Press Lo," was alarming. The Assistant Station Shift Supervisor (ASSS) initiated a work order to review the situation. However, the inspectors noted that the control room operators were unaware of this abnormal indication. Subsequently, the inspectors identified two other alarming RTUs, associated with the high pressure core spray system (HPCS), that the operators were unable to immediately explain; E22-N652 and E22-N656, "HPCS Pmp Disch Press" and "HPCS Pmp Flow," respectively.

The inspectors concluded that an apparent contradiction existed between the blackboard philosophy and operating with RTUs in alarm, along with the lack of awareness demonstrated by the operators. The inspectors discussed this with the Manager of Unit 2 Operations. NMPC acknowledged that operating with RTUs in alarm was contradictory to the blackboard philosophy, and initiated an internal action item to address the contradiction. The inspectors considered this area an unresolved item pending completion of the NMPC resolution of the issue and the subsequent NRC staff review. (URI 50-410/96-01-01)

2.3 Operational Aspects of Unit 2 RCIC System Maintenance

As described below, the inspectors pursued two operational-related problems identified during their review of maintenance to repair a packing leak on the Unit 2 reactor core isolation cooling (RCIC) system steam supply outboard containment isolation valve (2ICS*MOV121). (1) An apparent contradiction exists in the Limiting Conditions for Operations (LCOs) between the RCIC TS and the Remote Shutdown Panel (RSP) Instrumentation TS. (2) The reactor water

cleanup (RWCU) system was overpressurized during post-maintenance restoration. The inspectors identified no maintenance related concerns during this review.

2.3.1 RCIC System TS and RSP Instrumentation TS

On November 15, 1995, NMPC identified a packing leak on 2ICS*MOV121. After an engineering evaluation, and staging for MOV121 work, and other RCIC system maintenance, the valve was repaired during the week of January 7, 1996. To allow for the repairs, RCIC was declared inoperable on January 8, in accordance with TS 3.7.4; on January 9, repairs were started on the RCIC speed controller. In addition to the RCIC system TS; the controller is also covered by TS 3.3.7.4, associated with the RSP instrumentation.

The LCO for TS 3.7.4 allows the RCIC system to be inoperable for 14 days. The LCO for TS 3.3.7.4 requires the remote shutdown panel instrumentation and controls, including the RCIC speed controller, to be operable or restored to an operable status within 7 days. Based on the differences in the allowable outage times (AOTs), and the obvious need for the RCIC system to be operable in order for the RCIC controller to be functional, the inspectors questioned the Station Shift Supervisor (SSS) regarding the disparity between the two TSs. The SSS informed the inspectors that Unit 2 TS Interpretation (TSI) #49 (dated 3/2/93) provided the following guidance: "When the control circuit in the remote shutdown panel for one of these components [controlled from the RSP] is determined to be inoperable, the 7 day action statement of LCO 3.3.7.4 applies. If the component controlled from the remote shutdown panel is determined to be inoperable, then the appropriate action statement associated with the LCO for that system should be taken."

The inspectors discussed the justification of TS Interpretation #49 with licensing and Unit 2 management. Since the RCIC system would be required to be operable in order for the RCIC speed controller on the RSP to accomplish its function, why was the RSP TS 7-day action statement not invoked whenever the RCIC system was declared inoperable. Included in these discussions were a review of the TS basis for both requirements. The basis for TS 3.3.7.4, RSP instrumentation, is to permit sufficient capability to shutdown and maintain the unit in a hot shutdown condition from locations outside the control room, and to minimize the effects of a control room fire while achieving and maintaining safe shutdown conditions. According to NMPC, even with the RCIC system inoperable, the plant would still be able to achieve and maintain safe shutdown conditions using the automatic depressurization system (ADS) and residual heat removal system (RHS). Both ADS and RHS can be controlled from the RSP.

Although permitted by TS, RCIC and ADS and RHS could all be inoperable at the same time. However, since the LCOs for RHS and ADS are 7 days or less, the AOT for the RSP would essentially never be exceeded. The inspectors reviewed this issue with the TS Branch of the Office of Nuclear Reactor Regulations, and concluded that NMPC's interpretation was acceptable. But NMPC must exercise care to ensure that the complimentary systems are not out of service simultaneously, to fulfill the RSP objectives. Furthermore, the inspectors considered TSI #49 weak in clarifying and integrating the safety and design objectives in the interpretation for entering the respective LCOs.

2.3.2 RWCU Overpressurization During System Restoration

In response to ALARA [as low as is reasonably achievable] concerns related to the repairs of the packing leak on 2ICS*MOV121, the RWCU system was isolated to allow for the installation of temporary shielding. During the restoration of the RWCU system, a filling and venting process, a segment of the RWCU system piping briefly exceeded the design pressure of 1250 pound per square inch gage (psig). The maximum pressure observed was 1340 psig. A Deviation/ Event Report (DER) and an operability determination were written by NMPC to address this event. In accordance with procedure N2-OP-37, the RWCU system was filled from the control rod drive hydraulic system, which operates at approximately 1487 psig; but the procedure did not contain a warning that the RWCU system could potentially be over-pressurized.

After reviewing the DER and the operability determination from engineering, the inspectors questioned the need to report the event under 10 CFR 50.72, as a condition outside design basis. The Unit 2 Updated Final Safety Analysis Report (UFSAR), Figure 5.4-17, Sheet 3, indicates that the design pressure and temperature of the RWCU pump suction piping is 1250 psig and 575°F. Through discussions with the SSS and engineering, and review of related documentation, the inspectors ascertained that the temperature of the water used to fill the RWCU system was significantly less the system design temperature, approximately 200°F. As documented in the licensee's operability determination, industry standards (American National Standards Institute (ANSI) Standards B16.5 and B16.34), allow significantly higher pressures at lower temperatures for different classes of piping. The RWCU pump suction piping is Class 901, as described in the ANSI Standards, Class 901 piping is rated in excess of 1640 psig at temperatures of approximately 300°F, as compared to 1370 psig at approximately 600°F. Therefore, NMPC concluded that the temporary overpressure condition did not affect the system integrity, and that the system was not in condition outside the design basis, therefore not reportable.

Based on the information provided in the operability determination, the inspectors had no further concerns regarding the reportability of the RWCU pump suction piping overpressurization. However, this item will remain unresolved pending NRC staff's review of NMPC determination of the root cause, corrective actions to prevent recurrence, and a review for similar events. (URI 50-410/96-01-02)

2.4 Unit 1 Reactor Feed Pump Trip

On January 20, 1996, while operating at 100% power, the #11 reactor feedwater pump tripped unexpectedly. The expected annunciator did not alarm; the operators were alerted to the problem by the computer alarm for low lube oil pressure. The operators reduced reactor power to maintain reactor vessel water inventory while starting the standby feedwater pump; power was reduced to about 78% during the transient. Normal reactor water level during steady state operations is about 70 inches. During the transient, level decreased to 59 inches; the low level scram setpoint is 53 inches. The inspectors considered the quick actions taken by the operators to be the reason that the reactor did not scram. The cause for the pump trip was not immediately known.

DER 1-96-0148 was initiated by the SSS to investigate the loss of the feed pump and the inoperable annunciator.

During troubleshooting, NMPC determined the cause for the pump trip to be a failed Agastat series 2400 relay (63X) in the pump trip circuit. The inoperable annunciator was due to a second Agastat series 2400 relay (52Z). Review of the DER revealed that both relays had open coils, apparently due to aging and excessive heat. The 63X relay is regularly tested; however, the 52Z relay is not tested. The inspectors monitored the maintenance work for both investigation and repairs, and considered the efforts of all disciplines to be very good. Corrective actions to prevent similar failures in the future included a review to determine where else series 2400 relays were used, and establish a schedule for replacement of the relays, as required. All necessary replacements are scheduled to be completed by May 1997.

The lack of preventative maintenance and calibration of the annunciator relay reflected poor human factors attention, since a feedwater pump trip would not provide operators immediate notification of the problem. This concern was discussed with maintenance management at Unit 1, and will remain unresolved pending further evaluation. (URI 50-220/96-01-03)

2.5 Shift Work Hours

In early 1995, both units changed from a normal eight hour work shift to a twelve hour work shift for the facility staff who perform safety-related functions; e.g., senior reactor operators (SROs), reactor operators (ROs), health physicists, auxiliary operators, and key maintenance personnel. The change was implemented on a trial basis; the change was to be evaluated for permanent status after about a year. TS 6.2.2 for both units state:

> "Adequate shift coverage shall be maintained without routine heavy use of overtime. The objective shall be to have operating personnel work a normal 8-hour day, 40-hour week while the unit is operating ... Any deviation from the above guidelines shall be authorized by the Plant Manager ... in accordance with established procedures and with documentation of the basis for granting the deviation ... Routine deviation from the above guidelines is not authorized."

Since this was to be only a trial (or temporary) basis, NMPC considered that they were within the requirements of the TS. Therefore, no TS amendment request was submitted by NMPC to the NRC. Twelve hour shifts are common throughout the industry. The inspectors questioned NMPC, in January 1996, regarding the status of the twelve hour shifts. Specifically, a year appeared excessive for a temporary basis. The inspectors also questioned the lack of a documented basis for granting the deviation from the normal eight hour routine. NMPC's position was that the documentation was only required for exceeding the overtime portion of the TS. Subsequently, on January 25, 1996, NMPC issued internal correspondence regarding the temporary trial period of the twelve-hour shifts.

The union was scheduled to vote on this issue in February 1996; if the twelve hour shift is accepted, a TS amendment request would be submitted at that time. The normal work week schedule is unresolved pending final resolution by NMPC and further review by the NRC staff.
(URI 50-220/96-01-04 & 50-410/96-01-04)

2.6 (Closed) VIO 50-220/95-23-01: Containment Isolation Valve Unlocked

During a tour of the Unit 1 reactor building on October 13, 1995, an NRC inspector found a service water outside containment isolation valve closed but unlocked. The reactor startup prerequisites procedure, N1-PM-V16, required the valve to be closed and locked. Procedure N1-PM-V16 did not include an independent verification, as required by the NMPC locked valve program. In addition, there were inconsistencies between N1-PM-V16 and the service water system procedure, N1-OP-18, with respect to whether or not the valve needed to be locked. Lastly, UFSAR listed the inside and outside containment isolation valves for service water, but the valve numbers were reversed from the actual plant configuration and the approved drawings. The valve had potentially been unlocked since April 1995.

The inspectors reviewed the response to the violation. NMPC's apparent cause analysis indicated that the valve was improperly locked due to poor work practice on the part of the operator who was supposed to lock the valve, and again by the independent verifier. Also, the cause for the discrepancy between the procedural requirements for locking of the valve was ineffective procedure development. The system operating procedure and the system drawing were revised to require locking. Corrective actions to prevent recurrence included coaching of operations personnel on the proper method to lock a valve and verify valves locked.

3.0 MAINTENANCE (61726, 62703, 92902, 60705)

3.1 Maintenance and Surveillance Observations

The inspectors observed maintenance and surveillance activities to ascertain if safety-related work was conducted according to approved procedures, the TSs, and the appropriate industry codes and standards. Observation of activities verified that: limiting conditions for operations (LCOs) were satisfied, removal and restoration of equipment was controlled, administrative authorizations and markups were obtained, procedures were adequate, certified parts and materials were used, test equipment was calibrated, radiological requirements were implemented, system prints and wire removal documentation were used, quality control hold points were established, deficiencies were documented and resolved, and records were complete and accurate. In general, the activities observed and reviewed were effective with respect to meeting the safety objectives. No significant concerns were identified during the inspectors' review except as noted below.

3.2 Use of An Indeterminate Position on Unit 1 Mark-Up (Human Factors)

During a tour of the Unit 1 reactor building on January 10, 1996, the inspectors noted that the yellow holdout tag (#1-94-10134) for the limitorque

clutch on the drywell cooling water isolation valve (70-94) listed the required position of "as-is." The inspector questioned the SSS and several on-shift operators as to the meaning of "as-is" when applied to the position of a component on a mark-up. The general consensus was that "as-is" meant don't change or touch the component. Further questioning by the inspectors as to how they would verify the proper position as the second checker when hanging the tag received varied answers. For example, should the limitorque clutch handle be in the neutral/mid position or engaged?

The inspectors consider the use of a component position for mark-ups, that is not well defined, to be a poor practice that could lead to a component being unintentionally mispositioned. Unit 1 management agreed that this had the potential to cause a problem and that they would review the use the term "as-is."

3.3 Unit 1 EDG Cooler Replacement

On January 8, 1996, during operator rounds of the Unit 1 #102 emergency diesel generator (EDG), NMPC personnel identified chromate leak from the EDG cooling water expansion tank; chromates are indicative of a cooler tube leak. The EDG was declared inoperable and a work order (WO 95-02400) was processed to replace the cooler. Since the cooler was already scheduled for replacement in February 1996, all of the necessary planning had previously been completed.

The inspectors considered the activity to be well controlled, with maintenance supervisor frequently observing the work activities without becoming overly involved with the details. The WO was present at the work site. The safety markup appropriately isolated the EDG. When maintenance was complete, the monthly surveillance test was conducted before declaring the EDG operable. The inspector verified proper equipment lineup, in accordance with the operating procedure, to support automatic start in the event of a loss of power to the safeguards bus.

3.4 Unit 2 Residual Heat Removal System Valve Repair

During maintenance activities on a Unit 2 residual heat removal system (RHS) heat exchanger bypass isolation valve (2RHS*MOV-8A), NMPC identified two potential problems that could affect proper valve operation. (1) The stub shaft failed to rotate, as expected, during as-found testing; and (2) during as-left testing, the valve torque limit was excessive due to incorrect switch bypass adjustment. In both cases, NMPC determined the valve to be operable for accident and normal operating conditions for a limited number of strokes.

On January 17, 1996, while doing "as-found" testing for MOV-8A prior to actuator maintenance, Unit 2 technical personnel noticed that the stub shaft was not rotating as expected. The valve actuator, a Limitorque SMB-1 HBC, was removed for repairs. MOV-8A, an 18 inch butterfly valve, was operated by hand to verify that the stub shaft did not rotate. After consulting with the valve vendor, the cause was determined to be a shear failure of the dowel pin that aligns the disc axially in the valve body. The dowel pin was not intended to transmit torsional load. Testing subsequent to actuator maintenance indicated

that the drive shaft was engaged, and appropriate seating thrust was being applied.

During diagnostic testing on January 19, following actuator maintenance, MOV-8A was over-torqued by about 5.5%. The cause of the over-torque was an incorrect adjustment of the torque switch bypass. This over-torque was determined to be below what would cause a weaklink (valve body or shaft key) yield. The torque setting was returned to within normal limits and the valve returned to service after an engineering evaluation was completed. The evaluation determined that no significant valve damage was done, and that the resultant effect would not make the valve inoperable; essentially, 2RHS*MOV-8A would adequately perform it function. However, the valve would only be operable for a limited number of stroking evolutions.

The inspectors reviewed the valve drawings, the test traces, and the engineering evaluations, and verified that the torque setting was reset to below the limiting value before the licensee declared the valve operable.

3.5 Review of Unit 2 FIN Team Maintenance Initiative

Several months ago, Unit 2 implemented a trial program called Fix-It-Now; commonly referred to as the FIN team. The FIN team concept has been used at other nuclear utilities with generally positive results. The FIN team leader visited several of these utilities to gain first hand knowledge of the successes and failures that each had experienced. The FIN team is a multi-disciplined work group intended to address emergent issues that could interrupt the scheduled work items; the intent was to ease the manpower considerations when personnel are redirected from planned work to investigate emergent work. Also, as work load on the FIN team permits, they aggressively pursued the growing backlog of non-outage maintenance items at Unit 2.

The FIN team composition includes a senior reactor operator who is qualified as a station shift supervisor, this individual is the FIN team leader. He has overall responsibility for the FIN team, and is the focal point for coordination between the FIN team and the operations department (control room); he authorizes the work to be performed. The direct oversight of the day-to-day operations is the FIN team supervisor; he performs the functions of a maintenance department supervisor with respect to the processing of work orders. The current full-time FIN team members include two mechanics, two electricians, and four instrument and control technicians; in addition, on a rotating basis, the following are available, as needed, one control room operator, one radiation protection technician, and a dedicated warehouse representative.

The inspectors interviewed the FIN team leader, supervisor, and many of the team members; all were knowledgeable of their responsibilities and were very positive about the accomplishments of the FIN team to date. Since the various tasks do not get directly approved by the control room, the inspectors discussed with the FIN team leader the mechanisms used by the FIN team to ensure that the maintenance history updating and configuration control requirements were being met. These issues, and many others, were recognized by NMPC and addressed during the development of the Fix-It-Now procedure (N2-

MAP-MAI-0102). The inspectors confirmed that the activities of the FIN team are consistent with the normal requirements of the maintenance department. The weekly status report, detailing the number of items reviewed and worked, was reviewed and discussed with the FIN team leader. The inspectors attended one of the daily planning meetings, and observed the efforts to correct a pressure switch operation that appeared inconsistent with indicated pressure. The work order was generated by the FIN team, reviewed by the supervisor, and approved by the team leader. The work progressed smoothly, including adherence to all normal maintenance and radiation protection procedures.

The inspectors considered the FIN team to be a significant step toward controlling the perturbations on the daily work load of the maintenance department, and in reducing the maintenance backlog. The FIN team is a capable group, showing that the various disciplines can effectively work together without concern to discipline barriers.

4.0 ENGINEERING (37551, 92903)

4.1 (Closed) 10 CFR Part 21: Unit 2 Potential Design Defect of Cooper Bessemer Emergency Diesel Generators

On November 29, 1995, Cooper Energy Services issued a 10 CFR Part 21 report regarding a potential design defect of the Cooper Bessemer KSV Emergency Diesel Generators (EDGs). Specifically, due to a sleeve repair, the oil hole in the governor drive assembly top flange of the bearing retainer did not appear to extend through to the inside of the flange. This defect could result in the failure of the governor drive assembly, causing the EDG to be inoperable. Cooper Energy Services recommended that affected utilities verify an open oil passage in the assembly. Unit 2 has two Cooper Bessemer diesel generators installed for emergency applications.

The inspectors evaluated NMPC's actions related to issue. Included were discussions with the NMPC EDG system engineer, and a review of applicable documents. NMPC initiated a DER to track the completion of the Cooper Energy Services recommended inspections. The inspectors noted that the DER was initiated on November 28, the day before the 10 CFR Part 21 was issued; based on a conference call with the Cooper Bessemer Owners Group. During the conference call, NMPC determined that there was no immediate operability concern, based on routine monitoring of governor operating temperatures.

According to the system engineer, governor operating temperatures are monitored during monthly surveillance tests. A lack of oil would tend to increase the operating temperatures, the temperatures were consistently low. Therefore, NMPC considered the possibility of a lack of oil to the upper portion of the governor drive assembly to be unlikely. NMPC completed the recommended inspections earlier than scheduled, with no indications of the oil blockage defect.

The inspectors considered NMPC actions to address the November 29, 1995, Cooper Energy Services' 10 CFR Part 21 Report to be appropriate and timely.

4.2 Unit 2 Feedwater Heater Flange Leakage

On January 9, 1996, during a review of the Unit 2 Temporary Modification (TM) log, the inspectors noted a modification planned to temporarily repair a leak on a feedwater heater flange using a Furmanite process. Subsequently, NMPC was able to tighten the flange and stop the leak; thus it was not necessary to install the temporary modification.

Through discussions with the system engineer, the inspector ascertained that this was the second failure of this flange. As required by the NMPC procedure for on-line leak sealing, a DER was written to investigate the cause for the repetitive failures. According to the system engineer, the first leak was stopped on November 3, 1994, using a Furmanite compound, under TM #94-041; a permanent repair was performed to the flange during refueling outage RF04 (Spring 1995).

The system engineer was aware of previous industry problems related to repetitive on-line temporary repairs of valve and flange leaks. The inspector considered the continued emphasis to stop the leak, as opposed to a repeated Furmanite application, to be an indication of a good awareness of industry operational experience.

4.3 Emergency Temporary Modifications

During the review of an emergency temporary modification (TM) installed at Unit 2, the inspectors identified that the NMPC temporary modifications procedure (GAP-DES-03) allowed for the installation of emergency temporary modifications before the completion of the applicable supporting documentation, including the required 10 CFR 50.59 safety evaluation. This was evidenced by the installation of emergency TM #96-002 to the Unit 2 circulating water system, prior to the completion of the required 10 CFR 50.59 evaluation. The temporary modification procedure is applicable to both Units.

The inspectors observed the Unit 2 meetings related to the installation of the emergency temporary modification on the circulating water system. The inspectors reviewed the applicable documentation, including the emergency temporary modification package, a subsequent temporary modification, applicability review and safety evaluation, work history, and applicable Updated Final Safety Analysis Report (UFSAR) sections. Also, the inspectors reviewed the temporary modification procedure with respect to emergency temporary modifications, and discussed the use of emergency temporary modifications with both Plant Managers.

On January 31, 1996, a Unit 2 Reactor Operator observed that two of the four cooling tower basin water temperature instruments were indicating lower than actual. One of instruments had been out of service since July 17, 1995, but was not able to be repaired due to the plant operating. The circulating water system is not safety-related and is designed such that the cooling tower bypass valves open automatically when two of the four temperature switches sense a low temperature of 40°F. The actual cooling tower water temperature was approximately 59°F. Had the automatic function occurred without a valid low temperature condition, it would have reduced condenser efficiency and

could have resulted in a challenge to the reactor protection system (a safety-related system). To prevent this from happening, NMPC implemented emergency TM #96-002, on January 31, 1996, to de-energize the bypass valves in the closed position. The automatic function of the bypass valves is described in UFSAR Section 10.4.5.5.

The temporary modification was installed on January 31, 1996. In preparation for the installation of a more effective temporary repair, NMPC completed an Applicability Review and determined that a 10 CFR 50.59 Safety Evaluation was required, which was completed on February 2. On February 5, NMPC implemented TM #96-003, disabling the two malfunctioning temperature switches, effectively changing the opening logic for the bypass valve from two-out-of-four to two-out-of-two. Later on February 5, TM #96-002 was cleared.

During the events leading to the installation of the emergency temporary modification, the inspectors observed the involvement of NMPC management in the decision making process. They were aware that the function of the bypass valve was described in the UFSAR; and concluded that the modification would not impact plant safety.

The inspectors' review found TMs #96-002 and #09-003, the applicability review, and the safety evaluation to be appropriate, with the exception of the failure to complete the required 10 CFR 50.59 evaluation prior to the installation of the emergency TM #96-002.

NMPC Procedure GAP-DES-03 allowed the SSS to deviate from the procedure in emergencies to prevent personnel injury, equipment damage, or to ensure the margin of safety is not reduced (Paragraph 3.4.1). This paragraph is not to be confused with the SSS's authority to deviate from requirements to protect the public health and safety, as allowed by 10 CFR 50.54, Parts X and Y (Paragraph 3.4.2). In emergencies, the procedure allows for the modification to be installed prior to the completion of the paperwork, including the 10 CFR 50.59 safety evaluation. Subsequent to the inspectors' identification of the procedural inadequacy, NMPC initiated a DER to address the concern.

The failure of NMPC to ensure the completion of the required safety evaluation prior to installation of changes to the facility, as described in the UFSAR, is a violation of 10 CFR 50.59, "Changes, Tests and Experiments." NMPC Procedure GAP-DES-03, "Control of Temporary Modifications," is inadequate, in that it allowed the above to happen; as evidenced by the installation of emergency TM #96-002 prior to completion of the required safety evaluation. (VIO 50-220/96-01-05 & 50-410/96-01-05)

5.0 PLANT SUPPORT (71707, 71750, 92904)

During tours, the inspectors routinely monitor activities in the areas of radiation protection, emergency preparedness, security, fire protection, and general housekeeping. No significant deficiencies were identified during this reporting period, and minor problems were discussed with the appropriate supervision.

6.0 SAFETY ASSESSMENT/QUALITY VERIFICATION (71707, 90712)

6.1 (open) LER 50-220/94-03, Supplement 1: Missed Technical Specification Surveillance Caused by Inadequate Change Management

This licensee event report (LER) was initially reviewed in NRC Inspection Report 50-220/94-07. At that time, a violation was identified due to ineffective corrective actions to ensure the accuracy of the planned maintenance/surveillance test (PM/ST) database with respect to required frequency of surveillance tests. The NMPC response to the violation was subsequently reviewed and found acceptable, as noted in NRC Inspection Report 50-220/94-13.

The supplement was submitted to provide additional information related to 10CFR50 Appendix J testing requirements. The inspectors reviewed the supplement and determined that it satisfactorily described the new information. No additional review is required.

6.2 (Open) LER 50-410/95-12: Automatic Actuation of Standby Gas Treatment System Because of Inadequate Corrective Action for Snow Plugging of Filters

On December 11, 1995, with the reactor operating at 100% power, the Unit 2 standby gas treatment system (GTS) automatically initiated and the normal reactor building ventilation system isolated. Heavy snowfall and gusty winds at the time caused snow to accumulate on the filters in the inlet for the normal reactor building ventilation. The purpose of the filters is to protect the ventilation cooling coils by removing dust, dirt and insects from the inlet air. During the winter months the cooling coils are not in service and the system can be operated without the filters. The shift operators were aware of the deteriorating air flow and dispatched personnel to remove the filters from service. However, a low exhaust air flow condition occurred, which initiated an isolation of the reactor building ventilation and automatic initiation of GTS, before the filters were removed from service. Subsequently the filters were removed, and ventilation was returned to normal.

NMPC determined the root cause to be inadequate corrective actions to previously experienced ventilation degradations, in the 1980's, caused by snow plugging of the filters. However, the LER only addressed corrective actions associated with preventing the inlet filters from again clogging with snow.

The inspectors noted that the LER did not address the stated root cause of inadequate corrective actions. Through discussions with the Unit 2 Operations Manager, the inspectors ascertained that the current DER process ensures that corrective actions are adequately completed. Therefore, the corrective actions to address one root cause of "inadequate corrective actions," as described in the LER, were established with the development of the current DER process. The inspectors determined that the LER satisfactorily described the event. The inspectors also considered the stated corrective actions to be adequate to prevent recurrence of the snow plugging of the reactor building ventilation. Finally, based on past reviews of the DER process, the inspectors had no concerns regarding the ability to track and ensure

completion of corrective action. However, this LER remains open pending the submittal of a Supplemental LER from the licensee addressing the corrective actions to the stated root cause, and subsequent NRC staff review.

7.0 REVIEW OF UFSAR COMMITMENTS

A recent 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. During an approximate two month time period all reactor inspections will provide additional attention to UFSAR commitments and their incorporation into plant practices, parameters, and procedures.

While performing the inspections which are discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected and found them consistent with the observed plant practices, procedures, and parameters.

8.0 MANAGEMENT MEETINGS

At periodic intervals, and at the conclusion of the inspection period, meetings were held with senior station management to discuss the scope and findings of this inspection. The final exit meeting occurred on April 4, 1996. 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.