EXECUTIVE SUMMARY

INSPECTION REPORT 50-220/88-201

NINE MILE POINT UNIT 1

A team of NRC inspectors and contractor personnel conducted a Safety System Functional Inspection (SSFI) at Nine Mile Point Unit 1, to assess the operational readiness of the core spray system and the high pressure coolant injection mode of the feedwater (HPCI/FW) system. The assessment was accomplished by a thorough review of the design, maintenance, operations, quality assurance and testing of the systems. The following paragraphs summarize the significant findings and conclusions made by the inspection team:

1. The inspection team could not determine whether the core spray system would function as stated in the licensing documents for the following reasons:

   a. The Technical Specification limiting condition for operation (LCO) which allowed continued plant operations for up to seven days with an inoperable core spray loop appeared to be an unanalyzed condition.

   b. Analysis showing that adequate net positive suction head (NPSH) existed for the core spray pumps did not accurately reflect conditions that could be expected during a large-break loss-of-coolant accident (LOCA) with containment sprays in operation.

   c. Pump vortexing analysis did not account for the interactive effects of the two pump suctions which are in close proximity to each other. Calculations performed after the onsite inspection indicated that pump vortexing would not be a problem.

   d. System resistance curves did not account for all the components in the system.

   e. System pump curves did not appear to be controlled or validated by testing over the full range of expected flows.

   f. Potential flow diversion from the reactor through the combined pump discharge relief valve was not considered in any safety analyses.

   g. The system alarm setpoints and procedural responses appeared inappropriate for the core spray pump low suction and discharge pressure alarms, strainer high differential pressure alarm and core spray pump high discharge pressure alarm.

h. Emergency Operating Procedures (EOPs) did not appear to provide adequate guidance for core spray system operations in accident conditions.

i. The design of the core spray keep fill system did not appear to completely fill the piping down stream of the topping pumps. As a result, the core spray system appeared susceptible to water hammer problems during large-break LOCA situations.

j. The range of control room flow instrumentation for the core spray system was not adequate to measure the full range of expected system flows.

2. The inspection team could not determine whether the HPCI/FW system would function as stated in the licensing documents for the following reasons:

a. Independent calculations performed by the team indicated that the condensate and booster pumps would not provide the flow specified in the Technical Specification Bases at a reactor pressure of 450 psig.

b. No analysis was available to show that necessary water levels in the condensate storage tank could be adequately transferred to the hotwell without vacuum to support HPCI/FW pump flows. Calculations performed after the onsite inspection indicated that adequate flow would be achieved from the condensate storage tank to the hotwell to support HPCI/FW system operation.

c. The pump curves used for HPCI/FW testing appeared to be uncontrolled, and applied only to the motor-driven feedwater pumps (excluding the booster and condensate pumps).

d. The motor-driven feedwater pumps were not designed to support the frequent starting that may be required by HPCI/FW system reactor water level control modifications and operating procedures.

3. The electrical system design appeared adequate to support core spray and HPCI/FW systems operations. The licensee had previously initiated actions to reconstitute the electrical system design bases.

4. The inspection team made the following observations about licensee programs:

a. Examples were found where Surveillance Test Program data collection, results review, and acceptance value determination would not adequately support system operability decisions. This weakness appeared to be a direct result of poorly defined system design requirements.

b. Internal responses to industry information such as NRC Information Notices, GE Service Information Letters and INPO information did not always appear to be timely or sufficiently researched.

c. Investigation into problems and assessment of reportability in accordance with 10 CFR 50.72 and 10 CFR 50.73 did not always appear to be adequate.

d. The written periodic maintenance program did not include all recommended maintenance activities of the equipment vendor manuals or the actual periodic maintenance being performed on safety systems during the outage. A maintenance self assessment conducted by the licensee appeared to be a thorough review of the maintenance program and identified areas for improvement. Motor-Operated valve testing appeared to be a strength.

e. The QA Audit Program concentrated on programmatic issues and would not necessarily be able to identify significant technical issues with safety system operation, testing, design or maintenance. The QA Surveillance Program appeared to be more technically oriented and identified significant issues for resolution before restart.

f. System operating procedures had several deficiencies indicating a lack of attention to detail. However, operators demonstrated an excellent level of knowledge about the plant and system operating characteristics during system walkdowns and procedure walkthroughs. The capabilities of the site specific simulator also appeared to be a strength.

U.S. NUCLEAR REGULATORY COMMISSION

OFFICE OF NUCLEAR REACTOR REGULATION

Division of Reactor Inspection and Safeguards

Report No.: 50-220/88-201

Docket No.: 50-220

License No. Niagara Mohawk Power Corporation
301 Plainfield Road
Syracuse, New York 13212

Facility Name: Nine Mile Point 1

Inspection At: Oswego, New York

Inspection Conducted: September 12 - October 7, 1988

Inspectors: P.E. Dyer — 1/12/89
J. E. Dyer, Section Chief, NRR — Date

for P.E. Dyer — 1/13/89
H. I. Gregg, Sr. Reactor Engineer, RI — Date

J.A. Isom — 1/12/89
J. A. Isom, Reactor Engineer, NRR — Date

V. M. McCree — 1/13/89
V. M. McCree, Operations Engineer, NRR — Date

Consultants: *G. Morris, Westec Inc
*D. Prevatte, Powerdyne, Inc.
*D. Waters, Prisuta-Beckman Associates
*J. Wilcox, Prompt Professional Services, Inc.

Accompanying Personnel: *C. Haughney, NRR; L. Norrholm, NRR; *R. Capra, NRR; *J. Johnson, RI; *M. Haughey, NRR; *R. Benedict, NRR; *W. Cook, SRI; *W. Schmidt, RI; R. Temps, RI; *B. Clayton, OEDO; *D. Johnson, INPO

Approved by: for P.E. Dyer — 1/13/89
C. J. Haughney, Chief, RSIB, NRR — Date

*Attended Exit Meeting on October 7, 1988

Scope:

A special, announced inspection was performed of the operational readiness and functionality of the core spray system and the high pressure coolant injection mode of the feedwater (HPCI/FW) system at Nine Mile Point Unit 1 (NMP-1). The licensee's programs were reviewed in the following functional areas as they applied to the selected systems:

- Mechanical and Electrical Design
- Maintenance
- Surveillance and In-Service Testing
- Design Change Control
- Operations
- Quality Assurance and Corrective Actions

Results:

The inspection team identified significant concerns about the ability of the core spray and HPCI/FW systems to function as required during accident scenarios. These concerns included deficiencies with system design analyses and documentation, normal and emergency operating procedures and surveillance test results. Additionally, problems were identified with the licensee's programs for investigating and reporting significant problems to the NRC and evaluating available industry information for NMP-1 applicability. The team did not identify any functional concerns with the electrical system design supporting the two systems. Operator knowledge and the site specific simulator were also considered to be strengths. A total of 10 unresolved items were identified during the inspection and are listed in Appendix C to this inspection report.

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1. INSPECTION OBJECTIVES

The primary objective of the Nine Mile Point Unit 1 (NMP-1) Safety System Functional Inspection (SSFI) was to assess the operational readiness and functionality of the high pressure coolant injection mode of the feedwater system (HPCI/FW) and core spray system by determining whether:

(1) System design was adequate to perform the safety functions required by the design bases.

(2) Testing demonstrated that the system would perform the required safety functions.

(3) Maintenance of components ensured that the material condition would support reliable system performance.

(4) Procedures and training provided the operators with sufficient guidance to conduct system operations.

(5) Supporting systems such as electrical, instrument air and cooling were adequate to allow reliable safety system operation under design bases conditions.

A secondary objective of the SSFI was to assess the quality of the NMP-1 programs for maintenance, operations, testing, design control and quality assurance.

2. BACKGROUND

Nine Mile Point Unit 1 (NMP-1) is a Boiling Water Reactor, Model 2 (BWR-2) located near Oswego, New York. The plant has been shutdown since December 19, 1987 when the reactor was scrammed from 98 percent power because of an operating event. The event was initiated by a fractured feedwater flow control valve stem which started vibrating and was eventually felt by operators in the control room. This event is discussed in NRC Region I Inspection Report 50-220/88-02.

Since the event, a number of problems have been identified with the quality of plant activities. Consequently, the plant has remained shutdown and defueled under NRC Region I Confirmatory Action Letter 88-17. The licensee was in the process of developing a restart action plan to resolve a number of technical and managerial issues. The safety system functional inspection (SSFI) team visited the site while the plant was defueled to assess the readiness of the high pressure coolant injection mode of the feedwater (HPCI/FW) system and the core spray system to support plant operations in the future.

The core spray system was the only emergency core cooling system designed to inject water into the core. It was designed to adequately protect the core over the entire spectrum of loss-of-coolant-accidents (LOCAs) in conjunction with the automatic depressurization system and emergency condencers. The core spray system had two loops, each with two pump sets (core spray pump and topping pump), to provide coolant to the reactor pressure vessel (RPV) from the torus at reactor pressures below 365 psig. The system pumps had a rated flow of 3400 gpm at 299 psig pump discharge pressure. Normally isolated from the RPV, the pumps received a start signal from the RPV low-low water level signal and the isolation valves opened at an RPV pressure of 365 psig. A recirculation line, isolated by a relief valve, was provided from the combined discharge of the topping pumps to the torus to allow some flow through the pumps before the isolation valves would open. This feature prevented damage while the pumps were running in a shutoff head condition. High point vents and a keep fill system were provided to prevent voids from developing in the core spray system piping. The system was also designed with a test line to the torus that would allow periodic testing during plant operations. A simplified flow diagram of the system is provided in Figure 1 on page 4 of this report.

The HPCI/FW system was designed to provide a reliable source of high pressure injection to the RPV in the event of a small-break LOCA. The HPCI/FW system used the motor-driven feedwater pumps, booster pumps and condensate pumps to transfer water from the condensate storage tank to the RPV via the condenser hotwell. The system was not designed with a safety-related source of electrical power and was not considered in the LOCA analyses performed in accordance with 10 CFR 50, Appendix K. The HPCI/FW system did have a dedicated backup power supply from the Bennets Bridge Hydroelectric Plant and had specific operability requirements identified in the Technical Specifications.

A number of significant functional concerns with the systems were found during the SSFI. As a result, on October 26, 1988, the NRC issued a letter identifying the significant findings in advance of the inspection report so that corrective actions could be factored into the licensee's restart planning activities. On November 17 1988, a meeting was held at NRC headquarters to discuss the licensee's proposed corrective actions and formal responses to the NRC letter were

issued on December 8 and December 16, 1988. Section 3 of this report incorporates the applicable information provided by the licensee at the inspection followup meeting and in the formal responses, as well as NRC staff comments on the information.

NMP-1 CORE SPRAY SYSTEM

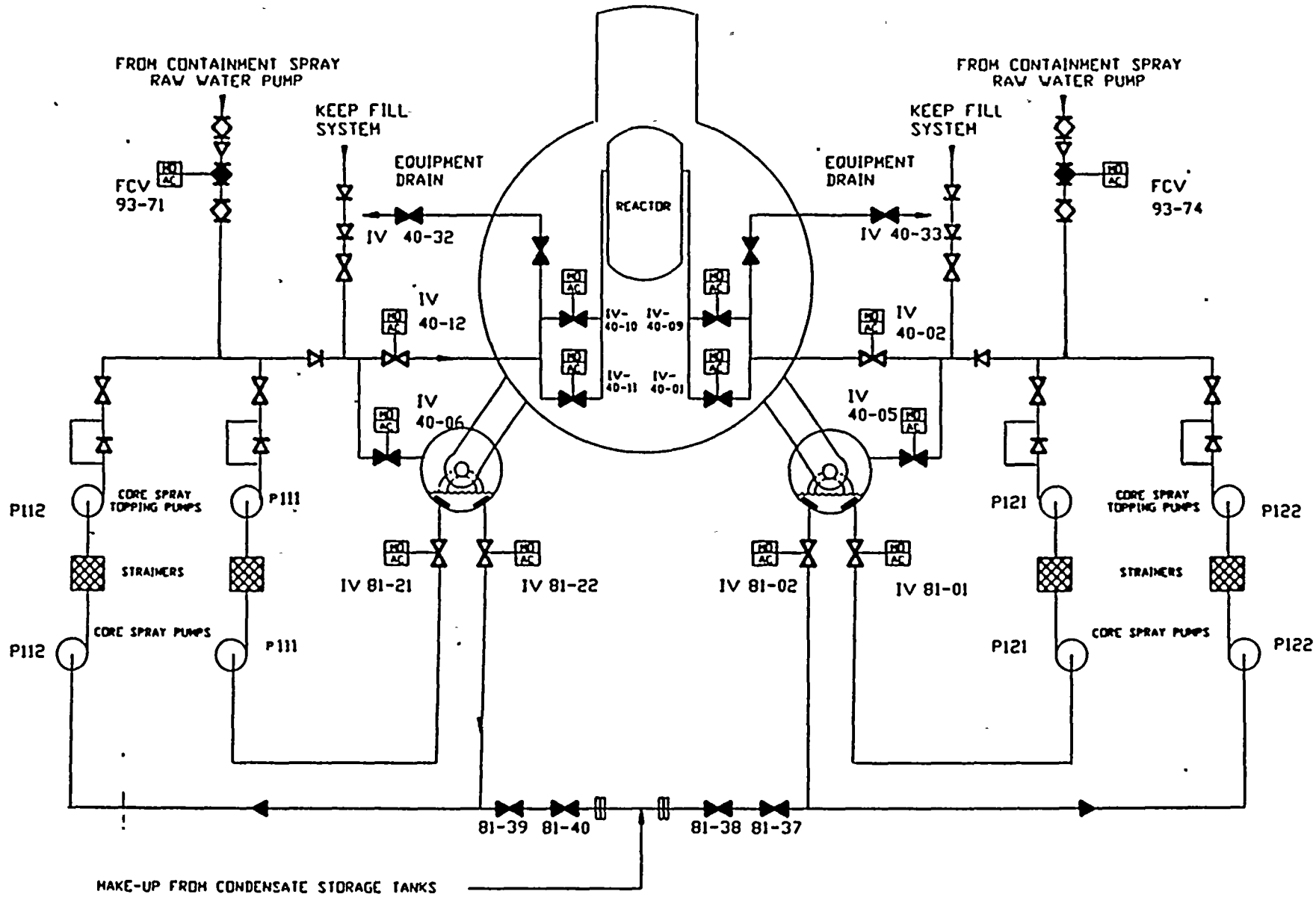

FIGURE 1

3. DETAILED INSPECTION FINDINGS

3.1 Core Spray System Design

The core spray system design was reviewed to determine whether design inputs to the various safety analyses and statements in the Final Safety Analysis Report (FSAR) and Technical Specifications were adequately supported by calculations and other analyses as required. Several aspects of the core spray system design appeared to be improperly defined and were not supported by design analyses. As a result, the team could not determine whether the core spray system was adequately designed to perform its intended functions.

3.1.1 Loss-of-Coolant Accident (LOCA) Analysis

The inspection team reviewed the licensee's analysis to demonstrate compliance with 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors," for the next operating cycle. General Electric (GE) Report NEDC-31446P, "Nine Mile Point Unit One SAFER/CORECOOL/GESTR-LOCA Loss of Coolant Accident Analysis," was issued in June 1987 and fully complied with the requirements of 10 CFR 50, Appendix K, "ECCS Evaluation Models." This report showed that the calculated peak clad temperature, peak local oxidation, and core-wide metal-water reaction were below the 10 CFR 50.46 limits for the proposed fuels under the analyzed spectrum of accidents. The licensee had reviewed the GE Report and revised the Technical Specifications for the fuel limits based on the results of the report. In August 1987, during the licensee's review, personnel in both the Design Engineering and Operations organizations identified that the GE report assumed that both core spray loops were always available, although this assumption was inconsistent with a Technical Specification Limiting Condition for Operation (LCO) for the system. Technical Specification 3.1.4.d allowed continued plant operations for up to seven days with one core spray loop inoperable. The core spray system was designed so that no single failure would take a loop out of service so the single loop situation was not considered by the LOCA Analysis. The team concluded that the 7-day LCO was less conservative than any postulated single failure to the core spray system and was an unanalyzed condition.

Before the inspection started, the licensee developed a draft Technical Specification Interpretation (dated August 23, 1988) to require shutdown within 10 hours if a core spray loop was inoperable, and was in the process of developing a change to the Technical Specifications to be implemented after restart. The team disagreed with the licensee's schedule for corrective actions and concluded that problems with the Technical Specification should be resolved before the system was declared operable.

At the inspection followup meeting the licensee committed to revise the core spray system Technical Specification before declaring the system operable. The licensee will evaluate the possibility of a Technical Specification to allow continued plant operation with one core spray loop operable after plant restart. The apparent failure by the licensee to translate LOCA Analysis assumptions into Technical Specification requirements will remain unresolved pending followup by the NRC (50-220/88-201-01).

Additionally, previous LOCA analyses had also assumed that two core spray loops were always available. The inspection team identified one instance, on November 11, 1987, where the licensee entered the 7-day LCO with the

reactor at power for a 17-hour period to repair a leaking check valve. As discussed in Section 3.8.1 of this report, it appeared that the licensee had not taken adequate corrective actions to investigate and report the full scope of this identified problem.

3.1.2 System Performance Analysis

The inspection team reviewed the analyses supporting the assertions made in the FSAR, Technical Specifications and safety analyses about core spray system performance and identified the following concerns:

(1) The system resistance curves did not account for the resistances associated with the piping from the torus to the discharge of the topping pumps, system flow orifice, pump suction grating, system strainer and one check valve. Collectively, these additional resistances could significantly increase the resistance coefficient for the system curves.

(2) The system flow analysis did not consider the flow that may be diverted from the reactor through the minimum flow relief valve during system operations. Design input provided to the team indicated that the valve reseat pressure could be as low as 280 psig which could divert flow from the reactor to the torus during core spray system operation.

(3) The text in Section VII of the FSAR stated that each set of pumps was capable of providing 3400 gpm to the spray nozzles at 299 psig, but this point appeared to be above FSAR Figure VII-2, "Core Spray Pump Characteristics." The curve shown in Figure VII-2 was used for determining acceptable pump performance during surveillance testing.

At the inspection followup meeting, the licensee stated that calculations were found after the onsite inspection which supported the system performance curves and assumptions about flow diversion. The curves would be validated at several flow points by system testing before declaring the system operable. These calculations were submitted to the NRC and are currently being reviewed. This issue will remain unresolved pending NRC review of the core spray system performance analyis and test data as part of an overall unresolved item concerning the adequacy of the core spray system design (50-220/88-201-02).

3.1.3 Net Positive Suction Head Analysis

The inspection team reviewed the licensee's analysis that showed the core spray pumps had sufficient net positive suction head (NPSH) for the full range of anticipated system operating conditions. The analysis asserted that adequate NPSH would be provided for the pumps; however, the team identified the following deficiencies with the assumptions used in the calculations:

(1) The pressure drop through the pump suction grating in a loaded condition was not considered in the calculations.

(2) The calculation for maximum torus water temperature achieved during the LOCA assumed a torus water temperature of 90°F at the beginning of the event. However, Technical Specification 3.3.2.e allowed the initial torus water temperature to be as high as 110°F before the reactor was required to be scrammed.

(3) The calculations assumed that the containment atmosphere would always be saturated at the temperature of the suppression chamber water. Therefore, the pressure would always be the saturation pressure corresponding to this temperature plus the partial pressure increase of the air caused by the temperature rise. However, should the containment spray system be actuated, such an equilibrium condition may not exist. The atmospheric temperature and the conditions of saturation in the containment could be significantly lower than the torus water temperature at the pump suctions, thereby providing less total pressure to contribute to available NPSH.

The team was concerned that the design of the core spray system prevented throttling flow to prevent cavitation. The core spray motor operated isolation valves received an open signal upon system initiation that was "sealed in," thus preventing later throttling. At the inspection followup meeting, the licensee stated that calculations had been performed which showed that adequate NPSH was available. These calculations were submitted to the NRC and are currently being reviewed. This issue will remain unresolved pending NRC review of the core spray system NPSH analysis as part of an overall unresolved item concerning the adequacy of the core spray system design (50-220-88-201-02).

3.1.4 Pump Suction Vortexing Analysis

The inspection team reviewed the licensee's analysis to show that the core spray system suction design was such that vortexing would not occur at the torus suction points for the full anticipated range of system operating conditions. The licensee's analysis asserted that vortexing was not a problem; however, the team identified the following deficiencies with design inputs to the calculations:

(1) An incorrect, non-conservative inside diameter dimension for the piping at the suction point in the torus was used in the analysis.

(2) The probable interactive effects of the two suction points for each loop being in close proximity to each other (approximately four feet apart) was not considered by the calculations.

As with the concern about adequate NPSH discussed in Section 3.1.3 of this report, the team was concerned about pump suction vortexing because the core spray system design did not allow throttling of the system isolation valves to reduce flow. At the inspection followup meeting the licensee stated that calculations were performed that showed an insignificant amount of interaction between the two torus suction points and that vortexing was not a problem. The inspection team reviewed the new calculations and concluded that vortexing was not a problem for the existing core spray system design.

3.1.5 System Susceptibility to Water Hammer

The inspection team was concerned that the present configuration of the core spray system appeared susceptible to water hammer during large-break LOCA situations. In the present design, the keep-fill lines join the core spray piping at points downstream of Injection Check Valves 40-03 and 40-13. This filled the piping from these valves to Inboard Isolation Valves, 40-01, 40-09,

40-10 and 40-11. However, the piping upstream of the injection check valves was not supplied by the keep-fill system. Much of the piping was above the torus level and free to drain back to the torus through the pumps by way of the topping pump discharge check valve bypass lines. This design would create voids when the system was not running and create conditions conducive to water hammer upon system initiation in response to a large-break LOCA.

With a large-break LOCA situation, the pumps would start soon after the break, and because the vessel would depressurize very quickly, the injection valves would start to open almost immediately before sufficient time would have passed for the air to have been removed through the relief valves. In this case, the water front in the pipe would travel very quickly toward the reactor vessel until it would reach the injection valves or other abrupt flow discontinuities, at which point the water hammer would occur. This situation could simultaneously occur in both lines and prevent the core spray system from fulfilling its safety function.

The licensee stated that no problems with water hammer had been observed during system surveillance testing. The team was concerned that existing tests did not simulate large-break LOCA conditions. At the inspection followup meeting, the licensee stated that a special test would be performed before startup to demonstrate that water hammer would not occur during worst-case system initiation conditions. This issue will remain unresolved pending NRC review of the water hammer analyses and proposed testing as part of an overall unresolved item concerning the adequacy of core spray system design (50-200/88-201-02).

3.1.6 Adequacy of System Alarm Setpoints

The inspection team was concerned that core spray system alarm setpoints were at values that would be expected during LOCA situations and that alarm response procedures directed actions that were not in the best interest of safety. The following observations lead the team to this concern:

(1) The core spray loop low-pressure alarm was set at 225 psig, decreasing, as sensed by a pressure switch downstream of the flow element. The purpose of the alarm was to detect a failure of system piping, but during a LOCA condition the alarm would be received as the RPV depressurized. Procedure OP-2, "Core Spray System," Revision 17, instructed the operator to check for various failure conditions, and if the opposite loop was operating normally, to shut down the affected loop. With the current knowledge that both loops of the system were required, this response could place the plant in an unanalyzed condition. In addition, when the alarm was received in one loop, it should soon be received in the opposite loop.

(2) The core spray pump low suction pressure alarm was set at 2.5 psig, decreasing. The function of the alarm was to warn the operator of impending cavitation, but according to the teams calculations, this setpoint was well above the required NPSH for the entire range of anticipated pump flow conditions. Procedure OP-2 directed operators to secure the train of pumps in which the alarm was received after ensuring that the other train in that loop was running. In an

accident condition this would unnecessarily reduce the system capability.

Additionally, if the alarm were received in one train, it could be imminent in the other train. After securing of the first train, the flow in the second train would increase, thereby lowering its suction pressure. This suction pressure drop could actuate the alarm in that train. A better response, were it available, would be to throttle flow to reduce the suction pressure required and to increase the pressure available. However, as previously described, the system design has no provisions for throttling the system isolation valves.

(3) The strainer high differential pressure alarm for the large strainers between the core spray and topping pumps was set at 5 psid, increasing. The purpose of the alarm was to alert operators to strainer loading during surveillance tests and LOCA conditions, however the setpoint appeared to be too low for this purpose. In the past, several work requests had been written to clean the strainers due to alarms received during testing at 3000 gpm flow, but no fouling was observed when the strainers were inspected.

Procedure OP-2 directed that the affected train be secured upon receiving the alarm. As with the low suction pressure alarm, to secure the affected train of pumps with both trains operating would probably cause the alarm to actuate in the opposite train because of the resulting increased flow.

It appeared that the alarm setpoints and response procedures were intended to provide guidance for abnormal conditions during surveillance testing and not during actual accident response situations. At the inspection followup meeting the licensee stated that calculations to support new alarm setpoints had been performed for accident conditions and these new values would be implemented before the core spray system was declared operable. The calculations supporting the new setpoints were provided to the NRC and are currently being reviewed. The NRC staff expressed concern at the meeting that procedures contained action statements that operators were prepared to ignore under certain circumstances because the responses were inappropriate for the situation. The licensee committed to review other safety-related systems to identify where response to system alarms differs for testing and accident situations and make the necessary changes to procedures. This issue will remain unresolved pending NRC review of the new alarm setpoints and supporting analyses as part of an overall unresolved item concerning the adequacy of the core spray system design (50-220/88-201-02).

3.1.7 Control Room Flow Instrumentation Range

The control room flow instrumentation did not appear adequate to cover the full range of expected system flows. The range of the installed instrument was 0 to 5000 gpm and according to the licensee's analysis, the expected flow with two pump sets running in the loop was approximately 6400 gpm. Regulatory Guide 1.97, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident," specified that the range of the control room flow measuring instrumentation for emergency core cooling systems to be 0 to 110 percent of the maximum anticipated flow. At the inspection followup meeting, the licensee committed to increase the range of the core spray system flow instrumentation before declaring the core spray system

operable. This issue will remain unresolved pending NRC review of the new core spray instrumentation range as part of an overall unresolved item concerning the adequacy of the core spray system design (50-220/88-201-02).

3.2 High Pressure Coolant Injection/Feedwater (HPCI/FW) System Design

The design of the HPCI/FW system was reviewed to determine whether statements made in the FSAR and Technical Specifications actually reflected system performance. The HPCI/FW system was not considered by any 10 CFR 50, Appendix K. LOCA analysis, but was required to keep the core covered in the event of a small-break LOCA. During the onsite inspection, the team determined that several aspects of HPCI/FW system performance were not adequately defined and this resulted in incorrect and misleading statements in the FSAR and Technical Specifications.

3.2.1 System Performance Analysis

The inspection team reviewed the licensee's analyses that supported the statements in the Technical Specification Bases about HPCI/FW system performance and identified the following discrepancies:

(1) The Technical Specification Bases asserted that each train of the HPCI/FW system could deliver 3800 gpm to the reactor vessel at reactor pressure. The team determined that the calculation supporting this assertion failed to account for the higher elevation of the feedwater nozzles from the condenser hotwell. During the inspection, the licensee stated that with the correction of this error, the analysis still showed acceptable results.

(2) The Technical Specification Bases asserted that at reactor pressures up to 450 psig, the condensate and feedwater booster pumps were capable of supplying 3800 gpm to the reactor vessel. Calculations performed by the inspection team and the licensee during the inspection revealed that these two pumps alone were incapable of delivering any flow to the reactor vessel at 450 psig. At the inspection followup meeting, the licensee stated that calculations were performed which indicated that 3800 gpm flow could be provided at 337 psig. The licensee stated that the Technical Specification Bases would be revised to reflect the correct pressure.

(3) The Technical Specification Bases specified that condenser hotwell level not be less than 75,000 gallons and inventory in the condensate storage tanks (CSTs) not be less than 105,000 gallons. However, during the onsite inspection, the licensee did not have an analysis to show that these values were adequate to support the spectrum of small-break LOCAs that the HPCI/FW system was intended to mitigate. The inspection team was concerned that under worst-case conditions with the condenser vacuum lost, the gravity feed-flow rate from the CSTs to the hotwell would not provide sufficient water for the pumps. Once the hotwell was empty, the condensate pumps could be damaged and the HPCI/FW system would be inoperable. At the inspection followup meeting the licensee stated that calculations were performed that showed adequate transfer of water from the CST to the hotwell would be achieved to support the HPCI/FW system upon a loss of condencer vacuum. The inspection team reviewed the new calculations and concluded that existing system design was adequate.

(4) The Technical Specification Bases stated that the motor-driven feedwater pumps would trip if a reactor high-water level was sustained for 10 seconds and the associated flow and low-flow control valves were closed. This modification was accomplished in 1984 to prevent over filling the reactor vessel to the point of spilling into the emergency condenser and main steam lines. The licensee recognized that frequent cycling of the feedwater pump motors was not desirable, therefore, a one-out-of-two-taken-twice control logic was included in the design to prevent cycling caused by a spurious signal. However, the licensee had no analysis to determine whether excessive cycling would not occur during a normal system response to various small-break LOCA conditions.

The feedwater pump motors were rated at 2500 horsepower and normally, large motors of this size can be restarted one time at the normal running temperature, but then must be cooled down for at least one hour before subsequent restarts. To restart more frequently could cause overheating of the motor and possible failure. The team was concerned that cycling the pumps would damage the motors and decrease the reliability of the HPCI/FW system. At the inspection followup meeting the licensee stated that pump cycling would occur only if the flow control valves would fail. Provisions for manual control of the flow control valves would be included in the system operating guidance. The inspection team considered these actions adequate.

The issue of unsupported assertions in the Technical Specification Bases about the HPCI/FW system design will remain open pending NRC review of the licensee's analyses supporting HPCI/FW system performance (50-220/88-201-03).

3.2.2 System Availability During Loss-of-OffSite-Power

Section VII.I.4 of the FSAR stated that the HPCI/FW system was available with limited offsite power from the Bennetts Bridge Hydroelectric Station 6000 kVA generator. Since the transfer was a manual operation, the generator could require approximately two minutes to be on line and the HPCI System restart sequence could begin. The restart sequence would take additional time before water could be delivered to the reactor vessel. The licensee could not provide an analysis that showed that with these delays, the design function of the HPCI/FW System, to prevent uncovering of the core for the small break LOCA, would be accomplished.

The team was concerned that for break sizes at the large end of the small-break spectrum, the vessel level would not be stabilized before automatic depressurization system (ADS) would be actuated, and the core would be uncovered. This would, in effect, turn a small-break LOCA, in which no fuel damage should occur if HPCI/FW performed correctly, into a large-break LOCA in which the core may be partially uncovered, and the probability of core damage and resultant radiological consequences is significantly increased.

At the inspection followup meeting, the licensee stated that the HPCI/FW system was not intended to support small break LOCAs during a loss of offsite power. After further review, the inspection team found this response to be consistent with previous licensing information. No further action is required on this issue.

3.3 Electrical System Design

The station electrical system was reviewed to determine whether power supplies and electrical equipment were adequately designed to support the intended operation of the core spray and HPCI/FW systems. This review included an evaluation of the analyses for electrical system circuit breaker coordination, voltage regulation, battery sizing, motor overload protection and the alternate power supply for the HPCI/FW system. No concerns were identified during the inspection with the electrical system design that would prevent proper system operation. The licensee had previously initiated actions to collect system design information and was performing an internal review of the electrical system. The inspection team considered this review a strength.

3.3.1 Circuit Breaker Coordination

The inspection team reviewed the coordination studies for the 4160 Vac and 600 Vac systems supplying HPCI/FW and core spray systems loads. The team concluded that the original studies performed in 1967 were adequate for the current electrical system configuration. The following observations were made during the review:

(1) The studies for non-vital Power Boards 11 and 12 demonstrated good coordination between the largest load (2500 hp reactor feedwater pumps motor) and the bus feeder breaker.

(2) The studies for safety-related Power Boards 102 and 103 demonstrated good coordination between the bus feeder breaker and a 1000 hp motor. This was conservative since the largest load on the safety-related power buses were the 500 HP containment spray raw water pump motors.

(3) The studies for safety-related Power Boards 102 and 103 did not include a review of the emergency diesel generator breaker overcurrent relay. A preliminary study performed by the licensee during the inspection revealed that adequate coordination existed between the emergency diesel generator breaker and the largest load for up to the locked rotor current of the load and for low resistance faults above twice the locked rotor current in the motor feeder cables. Overcurrent faults between these two current values could cause the emergency diesel generator breaker to trip before the load breaker tripped. The team concluded that this was a remote possibility and that adequate coordination existed.

(4) No deficiencies were found with the coordination for the 600 Vac System.

3.3.2 Voltage Regulation Studies

The inspection team reviewed a voltage regulation study performed in 1981 and the corresponding test data that supported the analyses. The teams concluded that the study was adequate and made the following observations:

(1) Impedance values used for Transformers 101N and 101S did not agree with values on the elementary electrical diagram. The team confirmed that the impedance values used in the study agreed with the nameplate data

on the transformers and that the electrical diagram was incorrect. The licensee initiated actions during the inspection to correct the drawing.

(2) The licensee had supplemented the main computer analysis for the safety-related buses with subroutines which determined the voltage drop from the 600 Vac buses to the major loads. The team considered this practice to be a strength.

(3) The licensee intended to perform new voltage regulation, load-flow and short-circuit studies for the electrical system, but no schedule had been established for the update.

3.3.3 Battery Sizing Calculations

The inspection team reviewed the battery sizing calculations for safety-related Batteries 11 and 12. The batteries recently had been replaced with new cells of the same type as the original cells. The inspection team found the battery calculations to be adequate and made the following observations:

(1) The current design assumed that the emergency diesel generator would load and the motor generator would charge the batteries after two minutes of discharge. The licensee had preliminary calculations that showed the life of the battery could be 30 minutes if the diesel generator failed to start. The team determined that this preliminary analysis appeared correct for Battery 11 if the load profile were properly documented. The engineering department intended to recommend that the battery surveillance test be revised to reflect the 30-minute battery life when the calculations were approved.

(2) Conservative values were used for the cell capabilities and the calculations were properly corrected for increased battery ambient temperature.

(3) The safety margins were determined for 58, 59 and 60 cells, allowing the licensee the option to operate with cells jumpered from the battery.

3.3.4 HPCI/FW System Backup Power Supply

The inspection team visited and reviewed the design of the Bennets Bridge Hydroelectric Station which provided a dedicated backup power supply for the HPCI/FW System. The team made the following observations:

(1) The 115kV transmission line between Nine Mile Point Unit 1 and Bennets Bridge through the Light House Hill Substation appeared to be a dedicated emergency line without any interferences from the Fitzpatrick Nuclear Station. This condition was properly reflected on system transmission drawings.

(2) Acceleration calculations and a test performed in 1974 demonstrated that Bennets Bridge could adequately support the HPCI/FW system starting loads as long as the voltage regulator was functional.

(3) Discussions with operators of Bennets Bridge and a walkthrough of lineup procedures revealed that the hydroelectric plant could be made available within approximately two minutes under the worst-case circumstances.

3.3.5 Electrical Protection of Motors

The inspection team reviewed the electrical protection for the motors associated with the HPCI/FW and core spray systems. Both the core spray and HPCI/FW pump motors were supplied from the 4160 Vac electrical system. The reactor feedwater pump auxiliary oil pump and motor-operated valves (MOVs) were 550 Vac motors which were fed from motor control centers through combination motor starters consisting of thermal magnetic molded case circuit breakers in series with motor contactors and thermal overload relays. The inspection team made the following observations during the review:

(1) The pump motor overloads were set to alarm at currents above the service factor of the motors. Both the core spray and HPCI/FW systems pump motors had a service factor of 1.15, which allowed the motors to carry a 15 percent overload above rated horsepower. The motor overloads were set to alarm at 120 percent of rated current, which allow indetected operation above the service factor and possible degradation of electrical insulation over the life of the motors because of elevated temperatures. The inspection team concluded that this issue was not a significant safety concern and the licensee agreed to review the adequacy of the pump motor overload setpoints.

(2) The reactor feedwater pump auxiliary oil pump overload protection was adequate.

(3) Core Spray Pump Isolation Valve 40-06 did not appear to have a thermal overload relay.

(4) The overload relays for Core Spray Drain Isolation Valves 40-30 and 40-31 were set so high that they would not detect the locked-rotor current of the motor.

(5) Major Order (MO) 2731 modified Feedwater Isolation Valves 31-07 and 31-08 in 1982 and the new overload relays were incorrectly set. The licensee assumed the motors were a continuous-duty type with a service factor of 1.15 instead of short-time duty motors with a service factor of 1. This resulted in the overloads being set too high.

(6) Thermal magnetic circuit breakers (15 and 20 amps) were used with the motor starters instead of the magnetic-only circuit breaker normally used with the thermal overload relays. This resulted in inadequate coordination between the circuit breakers and overloads for six core spray motor operated valves (40-01, 40-02, 40-09, 40-10, 40-11 and 40-12). In the case of Valves 40-09 and 40-10 (with 15 amps breakers) this inadequate coordination could result in the circuit breaker tripping before the overload relay. The team was concerned because this sequence of tripping would require an operator to enter the reactor building to reset the circuit breaker.

The inspection team was concerned about the deficiencies identified with the MOV overload protection, but concluded there were no immediate safety concerns. At NMP-1, the safety-related MOVs had the motor overloads wired in series with the automatic initiation circuitry. Therefore, actuation of the overload trips could prevent the system from fulfilling its safety function. By setting the motor overloads high, the licensee better assured reliable system operation,

but increased the possibility of long term motor insulation degradation. Before the start of this inspection, the licensee had initiated a review of existing MOV electrical protection. This internal review consisted of combining on a single time-current plot, the valve electrical signature, the thermal overload relay and the circuit breaker's characteristics. The motor's thermal limits were not included and the methodology and acceptance criteria were not defined in the study. The licensee agreed to factor the teams concerns into the overload protection review.

3.4 Design Change Control

The inspection team reviewed the licensee's design control program which included a review of the safety evaluations required by 10 CFR 50.59 and the updates of the design documentation when systems were modified. The inspection team identified deficiencies with both design documents and safety evaluations; however, the process for conducting safety evaluations appeared to be improving.

3.4.1 Safety Evaluations

The inspection team reviewed Nuclear Technology Procedure NT-100.B, "Preparation and Control of Safety Evaluation," Revisions 5 and 6, and selected safety evaluations to assess (1) the adequacy of design input to the safety evaluations, (2) the sufficiency of the evaluation in accordance with the criteria in 10 CFR 50.59 to determine whether an unreviewed safety question existed, (3) the adequacy of technical justification for the conclusion, and (4) the completeness of appropriate safety evaluation reviews. The specific evaluations reviewed are listed in Appendix B of this report. The following observations were made during the reviews:

(1) Revision 6 to Procedure NT-100.B provided more comprehensive guidance and better checklist "reminders" to the engineer performing a safety evaluation than did Revision 5. In addition, a notable improvement in the quality and completeness of safety evaluations was evident in the later safety evaluations reviewed.

(2) In Safety Evaluation 86-005, "Diesel Generator Upgrade," neither the narrative evaluation text nor the Compliance to NRC Standards Form NT-100.B-3 provided an adequate basis or discussion of the rationale for concluding that the probability of occurrence of a previously analyzed accident was not increased and that the modification did not create the possibility for a different type of accident than those previously evaluated.

(3) Safety Evaluation 86-016, for Modification 85-108, "Rerouting of Core Spray System Control Cables," Revision 1, was prepared to support a modification designed to establish cable separation for the four core spray pumps and the four motor-operated core spray suction valves. With respect to margin of safety, only the Compliance to NRC Standards Form NT-100.B-3 addressed the issue and stated that the margin of safety was not reduced since the modification did not affect any Technical Specification. NRC Regulation 10 CFR 50.59 requires that the evaluation consider whether the margin of safety as

defined in the in the basis for any Technical Specification was reduced. The short statement provided by the evaluator did not provide sufficient information to determine whether this attribute was evaluated.

(4) Safety Evaluation 87-029, "ATWS - Increase Liquid Poison Injection Capability," Revision 1, provided no analysis or justification for the conclusion that the modification did not create the possibility for an accident different from any previously evaluated. A restatement of the conclusion was all that appeared in the analysis, with no justification or basis. Similarly, no discussion or justification was provided in Safety Evaluation 88-003, "Emergency Generators' Diesel Fuel Storage Tank Replacement," Revision 1, for the conclusion that the modification did not create the possibility for an accident different from any previously evaluated.

(5) In Safety Evaluation 88-009, "Analysis for Lost Part In Feedwater System," Revision 1, sufficient basis for the no-unreviewed-safety-question conclusion was provided by combining the evaluation narrative text and Form NT-100.B-3. Part of this basis was provided in a referenced General Electric evaluation, that formed the primary justification for the situation not creating the possibility of an accident different from any previously evaluated. The completeness of this evaluation formed part of the basis for the team concluding the safety evaluations have recently improved.

(6) Safety Evaluations 88-013 and 88-015 were essentially identical and dealt with organizational changes. The narrative evaluation only described the functions of the organizational units and their new location in the organization. The conclusion that the change did not constitute an unreviewed safety question was based on the "above analysis," but no analysis was included. These evaluations had been approved by the onsite review committee and were scheduled for offsite committee review during the inspection.

In summary, the team concluded that, while the technical quality of safety evaluations appeared to be improving, a significant number of the current evaluations were not sufficient "stand-alone" documents to fully justify conclusions supporting a determination that no unreviewed safety question existed. However, since the team did not identify any concerns which would alter the conclusion of the reviewed safety evaluations, no additional reviews of previous safety evaluations were required.

3.4.2 Documentation Updates

The inspection team identified the following instances where design information was not properly translated into operating, test and safety study guidance:

(1) In 1978, the licensee modified the motor-driven feedwater pumps to replace the pump impeller. The licensee determined and stated in the safety evaluation that new impeller was equivalent to the old impeller, However, the team determined that the new impeller design provided 200 feet less head at rated flow (3800 gpm) and 500 feet at maximum flow. The licensee had not updated their design pump head curves to account for this impeller change.

(2) GE Study NEDE 30241, "Performance Evaluation of the Nine Mile Point Unit 1 Core Spray Sparger," used design flow inputs of 5020 gpm at 30 psia RPV pressure and 4860 gpm at 55 psia RPV pressure for core spray flow from one pump set. These values appeared inconsistent with the inputs for GE study NEDC-31446P which identified runout flow at 4800 gpm for each core spray pump set.

(3) In 1984, changes were made to the Technical Specifications which raised the setpoint for reactor vessel low-low-low level from elevation 294 feet-10 inches to 296 feet-6 inches. This is the setpoint at which the automatic depressurization system is actuated. The following corresponding design documents were not changed:

(a) Drawing Number C-35843-C, Revision 1, dated July 24, 1985, "Reactor Vessel Instrumentation, Level Ranges, Actuation Points, and Water Volumes."

(b) Drawing Number C-18015-C, Revision 87-039-C1, dated November 3, 1987, "Vessel Instrumentation, Piping and Instrumentation Diagram."

The team found applicable operating and test procedures were properly updated and the low-low-low level alarm was properly set in the plant and at the simulator.

(4) The original design of the feedwater system had the reactor feedwater auxiliary oil pump motors being powered from a non-vital power board that could only be fed from offsite power. In 1972, the power supplies for the auxiliary oil pump motors were moved from Motor Control Center (MCC) 151 to MCC 1671, which was capable of being powered from the onsite diesel generators. Neither Figure IX-1 of the FSAR nor the Electrical System Description document was revised to show this change in power supply for the reactor feedwater auxiliary oil pumps.

(5) The original design of the core spray system had all safety-related 4160 Vac motors being stripped from Power Boards 102 and 103. In 1971, this design was modified to leave one core spray pump on each bus following an undervoltage condition so that they would be ready to start when the diesel generator was connected to the bus. Neither FSAR Figure IX-1 and text, nor Surveillance Test Procedure NI-ST-R2, "Loss of Coolant and Emergency Diesel Generator Simulated Automatic Initiation Test" were modified to show that one core spray pump motor on each bus did not trip on undervoltage conditions.

The apparent failure by the licensee to update design documentation and the FSAR after system modifications will remain unresolved pending further NRC review (50-220/88-201-04).

3.5 Operations

The team reviewed operating and administrative control procedures, performed walkdowns of systems and plant areas, and conducted interviews with licensed and non-licensed operations personnel regarding the HPCI/FW and core spray systems. The documents reviewed are identified in Attachment B to this report. Weaknesses were found in the general areas of emergency and normal operational practices and procedures.

3.5.1 Emergency Operating Procedure Guidance

The inspection team reviewed the licensee's EOPs to determine whether adequate guidance was provided for operating the core spray and HPCI/FW systems under emergency conditions. The following deficiencies were identified during this review:

(1) Procedure EOP-4, "Primary Containment Control," Revision 0, Step 7.1, contained instructions to maintain torus water level between 10 and 11.5 feet, the normal operating band. If the water level dropped below 10 feet, the operator was referred to Procedure OP-2, "Core Spray System," Step I.21.d., to add water to the torus. This step directed the operator to restore water level to within the operating band utilizing the core spray keep-fill system which required securing one loop of the core spray system. The team determined that this was acceptable for normal operating circumstances, but was unacceptable in the post-LOCA condition when both core spray loops could be required. Additionally, the outside isolation valves and the test return line valves could not be repositioned without overriding system initiation signals to accomplish the fill operation. Thus, the specified procedure was deficient in specifying a means to add water to the torus during a LOCA event. The licensee concurred and prepared a revision to the procedure to supply water from an alternative source.

(2) The EOP General Instructions, EOP-1, Item 6, described the various limitations of the RPV level instrumentation under post-accident conditions. The team determined that the instruction was deficient in that no warning was provided concerning the limitations of low-low-low Level Instruments LI 36-19 and LI 36-20 when the core spray system was injecting into the vessel. The lower legs of these instruments were connected to the core spray lines so that the dynamic and backpressure effects of injection flow would make the instruments inaccurate. The team was concerned that the erroneous indication could produce operator confusion during an accident, even though these instruments were not used by the operators for casualty management during training evolutions.

(3) Graphs 2.1 and 2.2 in EOP-2, "Reactor Pressure Vessel Control," provided NPSH limitations for individual core spray pump operation. However, available flow indication in the control room was for combined pump flow, and there was no guidance in the procedure alerting operator's to this fact.

At the inspection followup meeting, the licensee stated that the identified procedural errors with the EOPs had been corrected. This issue will remain unresolved pending NRC review of the revised EOPs (50-220/88-201-05).

3.5.2 HPCI/FW System Guidance on Loss-of-Instrument Air

Procedure N1-SOP-6, "Special Operating Procedure, Instrument Air Failure," Revision 0, described actions to be taken with the HPCI/FW system to control reactor vessel water level upon loss of instrument air. The instruction to activate the Emergency Plan, if required, indicated that use of this procedure could be associated with a LOCA. Missing from this procedure were any instructions concerning control of the air-operated bypass valves back to the condenser for the condensate, booster, and feedwater pumps. Upon instrument air failure

many of these valves move to the open position. In this condition the HPCI/FW system may not deliver 3800 gpm to the reactor vessel at reactor pressure as stated in the Technical Specification Bases. During the inspection, the licensee agreed to enhance the procedure by providing specific direction for local control of the air-operated bypass valves.

3.5.3 Operator Training

The team reviewed the training program as it related to the core spray and HPCI/FW systems. Procedures and lesson plans were reviewed for adequacy and appropriateness of the information presented. In addition, six simulator scenarios were run with the assistance of the training staff to assess the information presented to the operator during transients involving the core spray system, the HPCI/FW system and loss-of-offsite power.

The lesson plans and simulator scenarios reviewed appeared to be adequate in the depth of information presented and the correctness of the information as related to approved plant procedures. Both licensed operator and non-licensed operator programs were included in the review. The simulator had been improved since its installation in 1985 to simulate extreme offnormal conditions such as primary containment pressure increases that would force containment venting decisions, anticipated-transients-without-scram (ATWS) conditions, emergency depressurization scenarios and steam cooling events. This capability to simulate a wide range of severe plant conditions for EOP training, was considered a strength.

3.5.4 Water Source for the Core Spray System

In addition to the concern raised in Section 3.1.1 of this report about the adequacy of the 7-day Technical Specification LCO for the core spray system, the team identified an additional concern. The Technical Specifications allowed work to be performed on the control rod drives if the core spray system was operable with certain specified conditions. A basic element missing from these conditions was available, adequate and redundant sources of water for injection. The team found no instances where the licensee had worked on the control rod drives without an available source of water for the core spray system. During the inspection, the licensee initiated a Technical Specification amendment to correct this problem.

3.5.5 Operating Procedures Review

The inspection team identified the following deficiencies with the operating procedures that provided guidance for the core spray and HPCI/FW systems:

(1) There did not appear to be a requirement to cross-reference setpoints, key instructions, and other vital information between plant drawings, procedures, training manuals, design documents or other controlled documents to ensure consistency following changes in any one document. It appeared, and was confirmed in discussions with licensee personnel, that a formal process to review the impact on other documents was not used when temporary changes or permanent changes were made to controlled documents.

(2) Procedures OP-2, "Core Spray System," and OP-16, "Feedwater System Booster Pump to Reactor," had numerous typographical errors, differences between control room indication labels and procedure descriptions, and differences between system drawings and procedure valve lineup sheets. Examples of the differences included:

(a) Valves CRS 743, 745, 734, 736, 747, 709, 749, and 711 on Procedure OP-2 valve lineup sheets, Table 1, were inconsistent with the core spray system drawing regarding normal position requirements (i.e., closed or capped and closed vs. locked-closed);

(b) Procedure OP-2, Section I.7, did not direct shutdown of Core Spray Topping Pump 111 if Core Spray Pump 111 tripped, which could result in pump damage;

(c) In Procedure OP-2, Table 1, Valves CRS 305, 307 and 767 were incorrectly identified as System 112 valves instead of System 111 valves. This could lead to operator confusion during the conduct of a valve lineup or verification;

(d) Procedure OP-16, Table 1, had discrepancies between actual valve requirements and procedural valve requirements (i.e., locked open/closed versus open/closed). Additionally, Table 1 specified position for valve 50-64 was open while the drawing requirement was to have the valve locked-open.

(3) Condenser hotwell level alarm setpoints provided in Procedure OP-15A, "Condensate System," appeared to be inconsistent with Technical Specification requirements and actual plant setpoints. Procedure OP-15A specified the condenser hotwell level high alarm at 66 inches and the low alarm at 42 inches while the Technical Specifications required the level to be maintained above 57 inches. During the inspection, the licensee determined that the instrument calibration procedure set the low-level alarm at 60 inches and the high-level alarm at 70 inches, which appeared consistent with the Technical Specifications. A change was initiated to the procedure to correct the error. This error had also been programmed into the simulator, where the low level alarm was actually set at 42 inches. Corrective action was initiated by the licensee to correct the simulator alarm setpoints to agree with the actual plant configuration.

(4) Procedure OP-46, "High Pressure Coolant Injection," included a description of the system operation following limited restoration of the 115 kV grid after a loss-of-offsite-power event. Notes were present describing some of the automatic and manual support systems which must operate to allow operation of the HPCI/FW system. The procedure did not provide guidance for the reactor building closed loop cooling (RBCLC) system, which cooled the condensate booster pump bearings, the feedwater pump lube oil and the instrument air systems, which were required for proper operation of the HPCI/FW systems, or the emergency service water system, which cooled the RBCLC system. Both the RBCLC and emergency service water systems had to be manually loaded onto the emergency diesel generator by the operator.

(5) Procedure OP-2, Section 1.24, directed actions to be taken by the operator in case Annunciator K2-4-7, "Core Spray Pumps Discharge

Pressure High," was activated by high pressure (445 psig) because of a stuck closed relief valve on the common discharge header of the core spray topping pumps. The procedure directed the operator to remove the system from service by placing the pump switches in the " pull-to-lock" position, but no direction was provided to reinitiate the system once reactor pressure decreased below 365 psig and the inboard isolation valves opened to allow vessel injection. The team was also concerned that consideration would be given to shutting down the pumps before it was firmly established that the core spray system was not required.

(6) Procedure S-SUP-Q6, "Control of Operator Aids," was used by the licensee to provide for the control, authorization, documentation and review of operator aids to ensure they were current and complete and to prevent personnel from using unauthorized operating and maintenance information in the performance of their duties. The team reviewed the implementation of this program and found that the program was appropriately implemented and the required reviews were conducted. The team was concerned that the number of active operator aids was excessive; 130 at the time of the inspection. Many of the operator aids appeared to be panel labels and instructions that could be made permanent. Additionally, the log of operator aids did not contain a copy of the aid. If an aid was damaged or destroyed, it would be difficult to replace exactly without such information on file. Operator aids were employed on the main control room panels to correlate the readings between the various water level instruments used by the operator during startup, normal operations and emergency conditions. The aids had been active since 1984, and consisted of paper copies taped to the panels between the instruments. The aid which correlated the RPV level fuel zone instrument reading to the top and bottom of the active fuel was very hard to read. Another RPV water level aid had informational portions cut away to enable it to fit between the instruments. Problem Report 258 was generated by the licensee in March 1988 to address the removal of operator aids from the control room and replace them with permanent labels, but no action had been taken by the time of the inspection. The licensee committed to review and revise the operator aids program to address the concerns identified by the inspection before restart.

Based on the number of deficiencies identified above and previous alarm response procedure issues discussed in Section 3.1.6 of this report, the team was concerned about the adequacy of station operating procedures and operator compliance with the procedures. This issue will remain unresolved pending NRC review of the licensees corrected procedures and operator aids (50-220/88-201-06).

3.6 Maintenance

The team reviewed the licensee's maintenance practices and procedures to assess whether the material condition of the HPCI/FW and core spray systems components would support reliable performance. Maintenance records were reviewed to determine if system components were being adequately maintained, work activities were observed for adherence to procedures, and system walkdowns were conducted to assess the physical condition of the system components. The inspection team concluded that there were several material deficiencies with the HPCI/FW and core spray systems that required resolution before restart and that further licensee attention was required to improve maintenance procedures.

The licensee's maintenance self assessment and MOV testing program appeared to be strengths.

3.6.1 Core Spray System Material Condition

The inspection team assessed the material condition of the core spray system during a walkdown of portions of the system with licensee maintenance personnel. The licensee had previously identified several deficiencies with the system that were to be corrected before restart. The inspection team identified the following concerns which had not been previously addressed by the licensee:

(1) The bolting for operators, yokes, and bonnets for core spray valves 40-01, 40-02, 40-05, 40-06, 40-09, and 40-10 did not have full thread engagement. The Quality Assurance Topical Report established correct bolt length as one thread beyond the face of the nut. During the inspection, the licensee issued Problem Report 458 to resolve this issue.

(2) Supports were loose for safety-related conduits IF 57, IF 58, IF 47, and IF 48. The team was concerned that these conduits may not meet their seismic design requirements. The licensee issued Work Request 144149 to correct these conditions.

(3) Core Spray Relief Valve 81-11 Discharge Line 82-3-LT had a pipe support installed near the relief valve that was not identified on the current isometric drawing (C26845-C Sheet 3) for the system. The licensee issued Problem Report 462 to resolve this issue.

(4) An indentation approximately two inches long existed on the core spray piping between seismic supports 81-SR-1 and 81-SR-2 near the system 112 core spray strainer. The dent appeared to be caused by a blow from a tool and had been freshly painted over. The licensee initiated Problem Report 471 to resolve this issue.

(5) Grease and oil were leaking from the operator for Core Spray Suction Valve 81-01. During the inspection, the licensee refurbished the valve replacing the O-rings and gaskets. The inspection team observed this maintenance activity and concluded that it was performed correctly.

(6) Core Spray MOVs 40-01, 40-09, 40-06, 40-10, 40-11, 40-12, and 40-05 had a significant amount of corrosion, surface oil, grinding dust and miscellaneous debris indicating a lack of general care during the outage. The licensee issued Work Request 142594 to correct these deficiencies.

(7) There was a half-inch weld spatter on the core spray line between inside Isolation Valve 40-01 and the RPV. The team was concerned that this weld spatter on ASME piping was not properly evaluated. Work Request 142326 was written to correct this problem.

During the inspection, the licensee stated that it realized the core spray system was not ready for operations. A thorough walkdown of the system would be conducted before the system was declared operable. The team was concerned that these walkdowns should be scheduled with sufficient lead time to allow proper resolution of identified problems.

3.6.2 HPCI/FW System Material Condition

The inspection team assessed the material condition of the HPCI/FW system during a walkdown of portions of the system with licensee maintenance personnel. The licensee had previously identified several deficiencies that were to be corrected before restart. The inspection team identified the following concerns which had not been previously addressed by the licensee:

(1) Outlet Isolation Valve 30-10 Feedwater Heater appeared to be modified without an adequate engineering evaluation. While operating on November 6, 1987, 20 holes were drilled in the valve flange, a pressure retaining part of the valve, to inject 155 cubic inches of "Furmanite" to repair a leak. There was no engineering evaluation performed to assess the structural integrity of the valve flange with the 20 holes drilled in it. The licensee had refurbished the valve during the outage to repair the steam cut leak and nonconformance Report (NCR) 1-88-0004 was issued to identify a half-inch crack in the bonnet of Valve 30-10 that appeared to be the result of the "Furmanite" injection process. The licensee dispositioned this NCR as acceptable based on grinding to remove the crack and a satisfactory dye penetrant test. The team was concerned that these modifications to repair Valve 30-10 may have rendered the valve unsuitable to support future plant operations. The licensee committed to perform an engineering evaluation of the current configuration of Valve 30-10 and repair or replace the valve as necessary.

(2) The I-beam type pipe supports for Feedwater Isolation Valves 31-01, 31-02, 31-07, and 31-08 had several fasteners that did not have full thread engagement. The Quality Assurance Topical Report established correct bolt length as one thread beyond the face of the nut. During the inspection, the licensee issued Problem Report 479 to resolve this issue.

(3) A pipe clamp, with no support attached, was fastened to the turbine building equipment drain line near Vent Valve FW-738. The licensee issued Problem Report 478 to resolve this issue.

(4) One feedwater line and one main steam line drywell penetration in the containment isolation valve room were missing metal clamps which contained the rubber material portion of the drywell penetration seal. The licensee issued Problem Report 461 to resolve this issue.

(5) Reheat Stop Valve 16-21 was severely corroded and showed a lack of periodic maintenance. The licensee issued Work Request 142622 to correct this problem.

(6) Several covers were missing from junction boxes on Conduit 16-1-56A and IF-41. The licensee issued Work Request 145404 to correct this deficiency.

(7) A chain fall was used as a temporary restraint on Feedwater Heater 112 and the second stage reheater drain tank to prevent the line from rubbing against a rod hanger. The licensee issued Problem Report 460 to resolve this discrepancy.

During the inspection, the licensee stated that it realized that the HPCI/FW system was not ready to support plant operations. A thorough walkdown of the system would be conducted before the system was declared operable. The

team was concerned that these walkdowns should be scheduled with sufficient lead time allow proper resolution of identified problems.

3.6.3 Maintenance Procedure Guidance

The inspection team observed the following practices that indicated that the licensee did not follow a policy of strict procedural compliance for all maintenance activities:

(1) The vendor manual for the Core Spray Strainers 81-05, 81-06, 81-23, and 81-24 specified that periodic checking of the strainer baskets should be performed without relying on high differential pressure alarm to indicate a need for cleaning. No formal periodic maintenance requirement existed for this task and maintenance personnel stated that the strainers were cleaned based on high differential pressure, which was contrary to the vendor recommendation. Additionally, the core spray pump and topping pump vendor manuals recommended performing semiannual and annual maintenance and inspections, including oil changes, oiling of stuffing box gland bolts and nuts, checking for free movement of the glands, and cleaning and relubricating bearings. The licensee had no such maintenance requirements identified for accomplishment on a periodic basis.

The team determined that the strainers were inspected as part of the Station Shift Supervisor (SSS) Instructions, which was an uncontrolled document that listed certain checks to be performed on plant equipment, such as checking the cleanliness of strainers in the core spray, containment spray and raw water systems, centrifuging oil sumps on the reactor recirculating pumps and performing other similar activities. When questioned about this activity, Operations personnel responded that no work requests were required to perform these checks nor were any procedures followed other than equipment markups and normal radiological control practices. The strainer checks were performed during plant refueling outages. The team was concerned that safety-related system boundaries were being breached and reclosed without proper consideration for QA oversight, cleanliness control, and proper torquing of flange bolts. During the inspection, the licensee initiated a change to the SSS instruction to require a work request with proper QA coverage to accomplish this maintenance activity and stated that this item would be incorporated into the periodic maintenance program.

(2) The team noted during the inspection of the torus water-level transmitter that instructions were written on the reactor building wall adjacent to Level Transmitter LT 58-05 that appeared to be excerpts from a procedure directing the calibration of the transmitter. Further review of the calibration procedures revealed that the instructions were based on an earlier version of the procedure and were now in conflict with the current, approved procedure. Discussions with maintenance personnel established that the instructions on the wall had not been used during the most recent calibration activities; however, it appeared that in the past these instructions had been used instead of approved procedures. Additionally, there were two test water-column scales marked on the drywell wall with tygon tubing mounted on the wall above the written instructions. During the inspection the licensee determined that these columns no longer served a useful purpose and removed them and the instructions from the core spray pump room wall.

(3) Procedure N1-EPM-GEN-M178, "Monthly Rounds," was employed by the licensee to direct electrical preventive maintenance rounds that plant personnel were to conduct monthly. A review of completed procedures revealed that the monthly rounds were not performed during the months of February, March, and April 1988. The rounds were restarted in May 1988 but did not include checking the motors, a requirement in the procedure. The tracking system did not identify the missed rounds. It was noted in the remarks section of the procedure that the procedure accomplishment frequency would be changed to quarterly, but this would occur after the missed rounds. The team was not concerned with the intended change to a quarterly frequency for the rounds identified in the procedure, but was concerned that the frequency change was made without first revising the procedural requirements.

(4) During a review of the licensee's practices for testing hydraulic shock suppressors (snubbers), maintenance personnel provided the team with a May 1986 Technical Specification Interpretation for determining and reporting inoperable snubbers found during testing. Two statements in the interpretation conflicted with the Technical Specifications Bases. The interpretation stated that if a snubber was found to be inoperable during cold shutdown, then the requirements for operability did not apply. Additionally, the interpretation stated that it was only intended that an engineering analysis be required if the snubber was found inoperable when the system was required to be operable. Licensee management stated that this interpretation had previously been found in error and had been cancelled. The team reviewed three copies of the controlled Technical Specification Interpretations and did not find this interpretation in any issued set. It appeared that maintenance personnel were working with an uncontrolled document. During the inspection, the licensee stated that the licensing and operation personnel who make the decision on reporting inoperable snubbers did not use the uncontrolled Technical Specification Interpretation and that inoperable snubbers were properly reported. The team concluded that this uncontrolled documentation was limited to the Maintenance Department.

(5) Several examples were noted where work and inspection activities were specified by memoranda and performed without followup changes to site procedures. Housekeeping assignment activities were specified in memoranda NMP 34262 and NMP 34269 but were not incorporated into AP 8.5, "Housekeeping and Cleanliness Control." The licensee's layup program activities were implemented for safety-related equipment in accordance with Memorandum NMP 38295 without being incorporated into an approved procedure.

3.6.4 General Housekeeping

During plant walkdowns, it was noted that the general housekeeping, especially in pathways outside the normal travel routes, was below industry standards. This was especially true in the main steam isolation valve (MSIV) and the drywell areas. The poor housekeeping appeared to be a result of individuals not completing work activities and not cleaning up their respective work areas. In addition, several examples were found where site Administrative Procedure AP 8.5 was not being followed; namely, the station superintendent did not conduct tours weekly as required by Paragraph 6.0 of the procedure, no target

dates were established for completion of corrective action for the last two inspections and there was no record of an audit being performed on the corrective action list as required by the procedure. During the inspection, the licensee established a schedule and initiated plant cleanliness inspections of specific zones.

3.6.5 Motor-Operated Valve Maintenance

The inspection team reviewed the licensee's maintenance practices for periodic maintenance of MOVs and the control of torque and limit switch settings. The licensee had conducted a detailed testing program under static system conditions, using the Motor-Operated Valve Analysis and Testing System (MOVATS) as previously documented in Inspection Report 50-220/88-24. Additionally, analyses were in progress to determine the final switch setpoints for design bases condition of safety-related systems as required by NRC Bulletin 85-03, "Motor-Operated Valve Common Mode Failures During Plant Transients Due to Improper Switch Settings." The team reviewed the analyses and test results and made the following observations:

(1) The test results identified one instance where the MOV was backseating because of an incorrectly set open limits. Core Spray Outside Isolation Valve 40-20 experienced a backseating thrust of 113,000 lbs during MOVATS testing. The licensee verified that the operator was rated for this thrust and performed an analysis which determined that this thrust would not overstress the stem. The inspection team was concerned that there maybe other parts of the valve that would be more restrictive than the stem.

(2) Test results also identified several instances where the measured thrust was significantly greater than the expected values. The worst-case appeared to be Core Spray System Outboard Isolation Valve 40-20, which had a measured thrust in excess of 97,000 pounds when the expected thrust was 40,800 pounds for a torque switch setting of 3. After consultation with the operator vendor, Limitorque, Inc., the licensee concluded that the problem was with the spring pack. The licensee intended to replace the spring pack at the next outage and to closely monitor thrust during the interim period. The inspection team considered this approach acceptable if the measured thrust valves were below the allowable thrust for the most limiting valve component.

(3) The analyses for determining thrust valves for the torque switch settings did not consider reduced voltage at the motor for determining the amount of thrust available from the motor.

(4) The team was concerned that the licensee's final torque switch settings would be extremely close to the motor-operator stall torques. The licensee agreed to verify the adequacy of the torque switch setpoints with respect to stall torque of the motor-operators as part of the thrust analyses.

(5) In many cases, both indicating lights and torque switch bypass functions were actuated by the same limit switch position. This has caused problems in the part with the licensee's measuring of stroke time as discussed in Section 3.8.2 of this report. The licensee was rewiring the MOVs to provide separate limit switches for indication and torque switch bypass functions.

(6) There did not appear to be an adequate method of controlling limit switch setpoints so that test personnel would be advised when switch position changed. The licensee stated that when all the safety-related MOVs were rewired so that valve position and torque switch bypass features would be controlled from separate limit switch rotors, the problem would be minimized. The team concluded that even with rewired control circuits, the testing personnel should know when switch positions were changed.

During the inspection the licensee agreed to factor the teams observations into the ongoing program for control of MOV switch setpoints.

3.6.6 Maintenance Self Assessment

In 1987 the licensee had conducted a Maintenance Self Assessment, using INPO Good Practice 85-038, "Guidelines for the Conduct of Maintenance at Nuclear Power Plants." The team reviewed the content of the assessment and concluded that it was a thorough review of the strengths and weaknesses within the licensee's Maintenance Department. Many of the corrective actions identified in the assessment were under development or in the process of being implemented during this inspection. It appeared that, when implemented, these actions would significantly improve the quality of maintenance. Additionally, the licensee was reorganizing the Maintenance Department and strengthening the coordination between electrical, mechanical and instrumentation activities. The team considered these corrective actions a strength.

3.7 Surveillance and Inservice Testing

The team reviewed the periodic test program implemented on the core spray, HPCI/FW and the 125 DC electrical systems to ensure that the surveillance and inservice test procedures used to verify the system functions were technically correct and adequate. The review consisted of a detailed evaluation of each of the test procedures listed in Appendix B of this report to verify that system functions described in the FSAR and Technical Specification requirements were properly demonstrated. Additionally, the team ensured that the appropriate sections of the ASME Codes were properly implemented in the inservice testing program. The team identified several deficiencies with the licensee's test program which appeared to be due to the poorly defined system design as discussed in Section 3.1 and 3.2 of this report. Also, the inservice test program did not appear to provide useful information for trending system performance and correcting problems before the system was declared inoperable.

3.7.1 Core Spray System Testing

The inspection team reviewed the testing performed for core spray system piping, pumps and valves and made the following observations:

(1) The pump curve used for the LOCA analysis did not appear to be effectively translated into surveillance test acceptance values to determine core spray system pumps operability. The Technical Specification acceptance values were determined from the design basis pump curve specified in Section VII of the FSAR, which was taken from GE Report NEDE-30241, "Performance Evaluation of the Nine Mile Point Unit 1 Core Spray Sparger." An uncontrolled copy of this curve was maintained in the Control Room for use by station operators in determining the operability

of the core spray system pumps. The test acceptance values were determined by adding and subtracting an instrument error to the curve to define an acceptance band and operators were trained to verify that the pumps test data plotted within this band. The team was concerned that the instrument error band should only have been added to the curve to obtain the minimum pump acceptance values. It appeared that previous pump test values falling within the identified band could indicate that the pump might not deliver the flow assumed by the LOCA analysis.

(2) Pump testing practices did not appear to agree with statements made in an NRC Safety Evaluation Report (SER) for core spray effectiveness in a steam environment. The SER, dated July 24, 1985, states that "The surveillance test procedure for core spray operability as presently written verifies that core spray pump performance characteristics over the full range of pressure and flow rates have not degraded. This range includes both pressure vs. flow points (i.e., 125 psia vs. 3400 gpm and 30 psia vs. 5020 pgm)." Procedure N1-ST-Q1, "Core Spray Pumps and Motor Operated Valves Operability Test," Revision 2, tested the core spray system pumps at only one point determined by a throttle valve position on the test line to the torus. This throttle position was such that test flows were approximately 3000 gpm at 300 psig pump discharge pressure, which was less than the flow range specified in the SER. The licensee stated that single point testing had always been the practice for core spray system surveillance testing. Previously, test flow rates of 4000 gpm were achieved; however, excessive vibration in test line piping necessitated reducing the test flow.

(3) The Technical Specification acceptance values for some core spray system MOVs appeared to be inconsistent with their safety function. Core Spray System Outside Isolation Valves 40-02 and 40-12 and Test Line Isolation Valves 40-05 and 40-06 were designed to reposition upon receipt of an initiation signal during system testing. Core Spray System Inside Isolation Valves 40-01, 40-09, 40-10, and 40-11 were designed to reposition upon receipt of an initiation signal during a normal standby system lineup. The team was concerned because the stroke time acceptance values for these valves with similar functions were different; Valves 40-01, 40-09, 40-10, and 40-11 had stroke time acceptance values of 20 seconds while Valves 40-02, 40-12, 40-50, and 40-60 had stroke time acceptance values of 25 seconds. During the inspection the licensee could not resolve the difference in stroke time acceptance values for these valves with similar functions. The team reviewed previous test data for all the valves and determined that the actual stroke times were less than 20 seconds for all the valves.

(4) Hydrostatic tests were conducted at insufficient pressure on the regions of the core spray system between the Core Spray Suction Isolation Valves 81-01, 81-02, 81-21, and 81-22, and the Core Spray Topping Pump Stop Valves 81-09, 81-10, 81-29, and 81-30. Procedure N1-ISI-HYD-424, "Reactor Core Spray System Hydrostatic Pressure Test," Revision 1, which was conducted every inspection interval and after system maintenance or alteration, required only an 80 psig test. The ASME Code, Section XI required this area of the core spray system to be hydrostatically tested to 1.25 times system design pressure if the design temperature was greater than 200°F, and there were no system relief valves. There were two design pressure

regions within the hydrostatic test boundary described above. From the core spray pump suction isolation valves to the suction of the core spray topping pump, the design pressure was 340 psig, and, from the core spray topping pump suction to the topping pump stop valves, the design pressure was 465 psig. The team noted that by conducting the hydrostatic test at 1.25 times design pressure, the licensee would not only comply with ASME Code Section XI, but would also ensure a conservative test of system integrity that was consistent with the high pressures experienced downstream of the core spray pumps upon system initiation.

At the inspection followup meeting, the licensee committed to validate the core spray system pump curves by testing over several points and control the pump curves after issuance. Additionally the hydrostatic test procedures would be reconciled with inservice testing program requirements. The issue of adequate testing of the core spray system will remain unresolved pending NRC review of the hydrostatic test procedure, pump curves and test data (50-220/88-201-07).

3.7.2 HPCI/FW System Testing

The inspection team reviewed the testing program for determining the operability of pumps, valves, storage-tank level, system initiation and automatic trips for the HPCI/FW system. The test program for determining HPCI/FW system operability appeared acceptable with one exception.

The acceptance values for determining HPCI/FW pump operability did not appear to accurately measure system performance. The Technical Specification requirements specified that the HPCI/FW system must be capable of meeting the pump head versus flow curve. The licensee limited testing to the motor-driven feedwater pumps and the curves used in the control room to determine operability were not adequately controlled. The curves used in the control room were not part of a controlled document and could not be verified to be consistent with the existing equipment installed in the plant. The team was also concerned that the actual performance of the HPCI/FW System was the combined performance of the condensate pumps, the booster pumps, and the feedwater pumps. The performance of the condensate and booster pumps were never checked with a surveillance procedure. Therefore, the actual total performance of the HPCI/FW system was never verified.

The licensee's position was that if the performance of the condensate or booster pumps were deteriorating, it would be detected during normal operation by the inability of the system to supply adequate flow to the reactor vessel. The team disagreed with this position because deterioration in pump performance could be very gradual, which would not necessarily be noticed, and the system had excess capacity to provide water to the reactor during normal operation. Any deterioration would be covered by wider opening of the feedwater control valves, which, again, would not necessarily be noticed. Even if it were noticed, there was currently no procedure to quantify the deterioration and compare it with acceptable limits.

At the inspection followup meeting, the licensee committed to issue controlled system pump curves, including booster and condensate pump performance, and validate the curves at several setpoints. The issue of HPCI/FW system testing

will remain unresolved pending NRC review of the pump curves and test results (50-220/88-201-08).

3.7.3 Battery Surveillance Tests

The inspection team reviewed the surveillance test program for the station batteries and identified the following concerns:

(1) Weekly and monthly surveillance tests to measure individual cell voltage did not identify values at which to perform corrective actions. The stated acceptance valve of 2.13 Vdc was the proper value for determining battery operability; however, the vendor specified an acceptable float voltage range of 2.20 Vdc to 2.25 Vdc for lead calcium cells. The team was concerned that corrective actions should occur before the battery reached an inoperable condition.

The one weekly surveillance data reviewed by the team recorded a pilot cell voltage of 2.12 Vdc. This value was below the acceptance criteria of 2.13 Vdc; however, no notice was made in the "REMARKS" section of the data sheet. The licensee later demonstrated, from comparison with other pilot cell data taken during the weeks prior to and following the questionable data, that the recorded value should have been 2.21 volts (a reversal of the two digits to the right of the decimal). The team was concerned that the recording error had not been detected either during signoff of the data sheets or by trending the data.

(2) Weekly and monthly surveillance procedures have an acceptance criteria for the overall battery voltage of only 106 volts. This low voltage should only be referenced in the battery service discharge test. The weekly and monthly surveillance acceptance criteria should be determined, based upon the product of the manufacturer's minimum float voltage and the number of cells in the battery. The procedure did contain a statement that the voltage "should be greater than 132 volts." However, the mention of the lower acceptance value of 106 volts could lead to operator confusion.

(3) The latest results of the battery service test and performance tests were reviewed. The performance test record included the results of the factory 8-hour test and this was considered acceptable as baseline data. The battery service test consisted of the 2-minute revised FSAR Case "B" load profile. The present battery service test procedure did not require the load profile to be compensated for temperature or even require electrolyte temperature be measured and recorded. The team was concerned because battery temperature affected capacity. A battery tested at 90°F would have 15 percent greater capacity than a battery at the minimum design temperature of 65°F.

The team considered the 2-minute service test unrealistic for the size cells installed at NMP-1. It was the team's understanding that Design Engineering would recommend that a longer test profile be used in future service discharge tests and that battery temperature will also be factored into the surveillance test acceptance values.

3.7.4 Motor Control Center Motor Starter Surveillance Tests

The team reviewed the surveillance procedures for the motor control center compartments of selected core spray and HPCI/FW systems motor-operated valves. These surveillance procedures checked the timing on the molded case circuit breakers and overload relays associated with the individual valve circuits.

The team questioned the test currents and acceptance criteria found on the test verification data for the overload relay heaters. The recorded values of test current did not correlate with the manufacturer's data. Design Engineering personnel had raised the same question with electrical maintenance in May 1988, but no resolution had been reached.

The team also questioned the acceptance criteria for the time-delay trip test for the molded case circuit breakers. Acceptance criteria contained in the procedure appeared to be based upon generic circuit breaker information and not on the specific circuit breakers installed in the licensee's motor control centers.

3.7.5 Inservice Testing Program

The inspection team reviewed the licensee's inservice test (IST) program as implemented on the HPCI/FW and core spray systems and made the following observations:

(1) The licensee had not implemented the IST program on the HPCI/FW system because it was not considered a safety-related system. The team was particularly concerned because it appeared that check valves at the discharge of the feedwater and booster pumps were not adequately tested or inspected. A gross functional check of the motor-driven feedwater pump discharge check valve was conducted quarterly when testing the pumps, but this test did not accurately measure the integrity of the pump internal components. Failure of the feedwater pump discharge check valves could cause a loss of the motor-driven pump because of reverse rotational damage. Such a loss had previously occurred on November 5, 1983 and was reported by LER 83-35. Undetected failure of both the feedwater and booster pump discharge check valves could result in inadvertent over-pressurization of condensate system low-pressure piping.

(2) The licensee could not adequately implement ASME Code Section XI testing and trending on core spray system MOVs and pumps because of insufficient margin between the design characteristics and the Technical Specification operability requirements. Before flow from the core spray system pumps were to degrade to the alert range of 93 percent of the baseline flow, the pumps would be declared inoperable because they would not meet the Technical Specification requirements. Similarly, before MOV stroke times degraded by 25 percent to the action range, the valve would be declared inoperable by Technical Specification requirements. This design feature made performance trending by the licensee ineffective.

(3) The licensee did not specify the required inlet pressure for their core spray pumps as required by ASME Code, Section XI. The inlet pressure for the core spray pumps did not vary appreciably during testing because the

pumps take suction on the torus and the torus level was maintained in a narrow band by the Technical Specifications. Because of this consistency, the team did not consider this deficiency to be significant.

(4) The data obtained during pump flow testing was inconsistent with the pump curves. The licensee only measured pump flow and not pump head during testing. It was assumed that the system resistance was fixed by the throttled position of the test valves. However, the team reviewed the test results and concluded that the measured flow variations could mean that the pump head was fluctuating by as much as 15 psig. A possible explanation was that the pump mini-flow relief valve was unexpectedly opening or leaking, thereby diverting flow from the reactor and changing system resistance. The licensee stated that this should not occur because the relief setpoint (320 psig) was above the pump test pressure (300 psig). During the inspection, this inconsistency could not be resolved by the licensee, but will be unresolved as part of the verification of core spray system testing concerns (unresolved item 50-220/88-201-07).

3.8. Quality Assurance and Corrective Action Programs

The inspection team reviewed the licensee's programs for ensuring quality in the plant and taking prompt corrective actions when deficiencies were identified from industry sources and within the plant. The specific documents reviewed are listed in Appendix B to this report. It appeared that the licensee's corrective action program was weak in investigating plant problems and reviewing available industry information. Additionally, the licensee had previously identified improvements for the QA Audit and Surveillance Programs which appeared to be implemented for the QA Surveillance Program and in progress for the QA Audit Program.

3.8.1 Corrective Actions for LOCA Analyses Results

The inspection team reviewed the licensee's corrective actions taken with regard to the concern about the adequacy of the 7-day LCO for the core spray system discussed in Section 3.1.1 of this report. The inspection team determined that the following sequence of events were pertinent:

- In 1974, Technical Specification 3.1.4 was issued for the core spray system as part of the initial license. The system contained two loops with two pump sets per loop and was thought to be 400 percent redundant. The LCOs were established at 15 days for one disabled pump set and 7 days for one loop out of service.

- In October 1975, the initial 10 CFR 50, Appendix K LOCA Analysis was performed assuming two core spray loops were always available. The analysis used the SAFE/CHASTE Computer Model which identified the small break LOCA as the limiting condition for reaching the 10 CFR 50.46 limits for peak clad temperature (2200°F). This analysis became the bases for a proposed amendment to the Technical Specification fuel limits submitted on October 31, 1975. The core spray system LCOs were not identified for revision to be consistent with the LOCA analysis design inputs as part of this proposed amendment.

- In 1983, GE Report NEDE 30241, "Performance Evaluation of the Nine Mile Point Unit 1 Core Spray Spranger," was performed, using a new SAFER/CORECOOL

Computer Model to evaluate core spray sparger operation in a steam environment. Although not formally used as a bases for Technical Specification limits, this more accurate analysis showed that the small break LOCA was no longer the limiting condition for meeting 10 CFR 50.46 limits; analyzed peak clad temperature for the small-break LOCA was now approximately 300°F below the limit.

- In June 1987, 10 CFR 50, Appendix K LOCA Analysis (NEDC 31446P) was performed using the SAFER/CORECOOL/GESTR Model to determine Technical Specification limits for the next operating cycle. The analysis assumed that two core spray loops were always available to support LOCAs.

- On August 17, 1987, personnel from Operations, Engineering and Licensing met to discuss a potential problem with an existing Technical Specification LCO for the core spray system and NEDC 31446P assumptions. The concern was that the 15-day LCO should be reduced to a 7-day LCO to be consistent with NEDC 31446P. Internal memoranda dated August 19 and 25, 1987, documented the meeting results and indicated that the group decided the existing 15-day LCO was acceptable under the new analysis. The adequacy of the existing 7-day LCO for NEDC 31446P was not discussed at the meeting. The licensee had contacted GE prior to the meeting and was told that the LCOs were both adequate as written.

- On September 1, 1987, Engineering issued an internal memorandum which identified that the 7-day LCO for core spray system may be an unanalyzed condition by NEDC 31446P and require revision before the next operating cycle. This memo was distributed to Operations personnel but not the Licensing organization.

- On September 22, 1987, Licensing issued a memorandum in response to concerns raised at the August meeting which stated that the 15-day LCO should be changed to a 7-day LCO to be consistent with NEDC 31446P and other LCOs. The memo also identified that previous 10 CFR 50, Appendix K LOCA analyses had assumed two loops of the core spray system to always be available. The existing 7-day LCO was not discussed as being an unanalyzed condition.

- On November 10, 1987, operators took one loop of the core spray system out-of-service for 17 hours to repair a leak from a check valve. The operators entered the 7-day LCO without realizing it was an unanalyzed condition.

- On December 19, 1987, the plant entered an extended outage after a feedwater transient event.

- On August 23, 1988, after realizing that the 7-day LCO was an unanalyzed condition, the licensee drafted a Technical Specification Interpretation that prevented entering the 7-day LCO for the core spray system. This interpretation was still in the review process at the time of this inspection, but was to be issued before startup.

- On September 15, 1988, the NRC inspection team determined that the 7-day LCO was an unanalyzed condition by the licensee's 10 CFR 50, Appendix K

LOCA analyses and that the plant had entered the 7-day LCO when operating on November 10, 1987. The licensee completed the proper investigation and NRC reports upon notification by the team.

- In a September 22, 1988 letter to the licensee, GE confirmed that using only one core spray loop and the previous 10 CFR 50, Appendix K LOCA analyses assumptions, the SAFE/CHASTE Model Analyses would yield a higher analyzed peak clad temperature then previously determined. This new value would be above the 10 CFR 50.46 limits. However, the GE letter also stated that previously used conservative design input assumptions concerning pump delivery pressure could be changed to reduce the analyzed peak clad temperature below the 10 CFR 50.46 limits. The team agreed with this assessment and concluded that the previous SAFE/CHASTE Model Analyses could be revised to indicate acceptable results with one core spray loop.

The inspection team was concerned about the licensee's corrective actions in this situation and drew the following conclusions about the sequence of events:

(1) The licensee's corrective action program was ineffective for resolving a potentially significant deficiency identified with the Technical Specifications for the core spray system that would allow plant operation in an unanalyzed condition. Collectively, sufficient information was available with the licensing, operations and engineering organizations to determine that the existing 7-day LCO was an unanalyzed condition before the plant unknowingly entered the 7-day LCO on November 10, 1987. The team found no evidence to suggest that the licensee realized this fact until after the plant entered the current outage.

(2) The licensee failed to take adequate corrective action to investigate and report the problems with the 7-day LCO when it was first realized in approximately August 1988. The corrective actions were limited to drafting a Technical Specification Interpretation. No investigation of previous operations was conducted to determine whether the plant had previously been operated in an unanalyzed condition; the NRC was not notified in accordance with 10 CFR 50.72 and 10 CFR 50.73; and a Technical Specification change was not promptly initiated.

(3) The initial cause of the problem appeared to be the improper translation of the 1975 10 CFR 50 Appendix K LOCA Analysis assumptions into Technical Specification requirements as required by 10 CFR 50.46.

The licensee's failure to properly implement the requirements of 10 CFR 50.46 to revise its Technical Specifications to conform with the LOCA Analyses specified in 10 CFR 50, Appendix K and the failure to take adequate corrective action and make necessary reports to the NRC will remain unresolved as part of an overall unresolved item on the licensee's corrective action program pending followup by the NRC (50-220/88-201-09).

3.8.2 Corrective Actions for MOV Testing Results

During a review of the MOV stroke time test results for core spray and HPCI/FW system valves, the inspection team identified three valves which appeared to have stroke times in excess of the Technical Specification limits; Core Spray System Vent Valves 40-30 and 40-31 and Feedwater Isolation Valve 31-07. In LER 88-14 (May 10, 1988), the licensee identified that Valve 40-30 stroke

times had been out of specification since 1986. The root cause of the problem was that indicating lights used to measure valve stroke times and the limit switch contacts used for the torque switch bypass function were driven from the same limit switch rotor. The limit switches were adjusted to provide adequate torque switch bypass functions but no adjustments were made for the valve stroke time determinations.

The inspection team review applied the same criteria described in LER 88-14 for determining actual valve stroke time from the measured stroke time during testing. For Feedwater Isolation Valve 31-07, the most recent MOVATs testing in 1986 indicated a disc bypass margin (DBM) of .886 (52.2 sec/58.9 sec). The DBM was the fraction of valve travel measured by the indicating lights. Therefore, applying this DBM to a Technical Specification limit of 60 seconds for valve 31-07 would yield a measured acceptance valve limit of 53.2 seconds. A review of test results for Valve 31-07 revealed measured stroke time of 55.8 seconds on January 25, 1986, 56.0 seconds on June 14, 1986 and 55.0 seconds on October 21, 1987. The team concluded that each of these stroke times were above the Technical Specification limits. For Valve 40-31, no MOVATs data was available for the most recent limit switch setpoints, but data from the licensee's September 18, 1986 response to NRC Bulletin 85-03 "Motor Operated Valve Common Mode Failures During Plant Transients Due to Improper Settings," indicated that the closed torque switch was bypassed by 23 percent yielding a DBM of .77. Applying this calculated DBM to a Technical Specification limit of 30 seconds yielded a measured acceptance valve of 23.1 seconds. This measured acceptance value had been exceeded 17 times during monthly stroke time tests since August 1986. This issue of adequate investigation of reportable events will remain unresolved as part of an overall unresolved item on the adequacy of the licensee's correctice action program (50-220/88-201-09).

3.8.3 Operational Experience Assessment Program

The team reviewed the adequacy of the licensee's Operational Experience Assessment (OEA) Program which included the review of documents such as NRC Information Notices and Circulars, INPO SOERs and SERs, and General Electric Company Services Information Letters (SILs), as well as interviews with licensee personnel involved in the OEA program. Overall, the licensee's OEA program was weak. Discussions with licensee personnel revealed that the program was formalized around 1982 and responsibilities were assigned to the Technical Support Group as part of their job responsibilities without establishing a separate OEA group. This mode of operation continued until August 1988, when a group with specific responsibilities for OEA was established. The following specific concerns were identified during the inspection team's review:

(1) Internal Memorandum NMP 31552 of March 10, 1988 closed out 11 related NRC Information Notices, INPO SOERs and INPO SERs concerning valve mispositioning because of human error during operations and maintenance activities. The response addressed the specific issue of valve mispositioning, but did not address the broader concerns of equipment, instrument and component labeling identified by NRC Information Notice 87-25 and INPO SOER 85-2. Plant walkdowns conducted by the team revealed a labeling program that was below industry standards, and there did not appear to be a significant effort being made by the licensee to improve

plant labeling. Additionally, the licensee stated in NMP 31552 that training of non-licensed operators in the manipulation of all of the major types of valves installed in the plant was conducted in theory lesson NLT-20 "Nuclear Power Plant Fundamentals - Valves, Traps and Pipes," and included training on how to position the valve and how to verify its position when performing a valve lineup. Review of the lesson plan, which was renumbered as OPS-1-NLO-002-T20-01, revealed that this information was not included in the plan; rather, the licensee relied on on-the-job-training activities to teach new operators this information. The information in the OEA memorandum appeared to be in error. The team was concerned about this error because an NRC Augmented Inspection Team had identified a similar concern at Nine Mile Point Unit 2 as a contributing cause to an event as discussed in Inspection Report 50-410/88-01.

(2) Internal Memorandum NMP 30292 of March 14, 1988 closed out 22 related NRC Information Notices, INPO SERs and an INPO SOER concerning undetected check valve failures. The response concentrated on INPO SOER 86-3, "Check Valve Failures or Degradation." The team did not determine whether the INPO document encompassed all the issues identified by the other documents. INPO SOER 86-3 discussed undetected check valve failures due to misapplication of the valve in the system and inadequate preventive maintenance. The SOER made recommendations for improved testing and inspection of check valves and a design review to determine whether the proper valves were installed in the correct locations for the intended functions. The recommendations were to be applied to the main steam, nuclear service water, diesel starting air, suppression pool support, main feedwater and residual heat removal systems. The team identified the following concerns with the licensee's internal response:

(a) The memorandum referenced five related check valve failures at NMP-1 from the period of August 1982 to June 1986 and concluded that this was an acceptable performance for ten years of operation. The team was concerned because it appeared that the number of check valve failures was increasing as the plant aged.

(b) The response to the recommendation for improved testing and inspection of check valves was to state that the present preventive maintenance practices for check valves were in compliance with the regulatory requirements of 10 CFR 50, Appendix B and ASME Code, Section XI and that all the recommended systems were included in the program. Therefore no additional testing was required. This response appeared inconsistent with licensee practices since HPCI/FW system check valves were not included as part of the IST program.

(c) The licensee performed a review of plant isometric diagrams, purchase orders and some visual inspections of check valves to satisfy the design review recommendation. Although this review identified several instances of improper location and orientation of check valves, the design deficiencies were dismissed because no problems with these valves had previously been identified in the maintenance history.

The team concluded that the licensee was not taking advantage of the information available on check valve maintenance, testing and design because NMP-1 had not experienced similar failures.

(3) IE Circular 78-15 advised of problems with Anchor Darling tilting disc valves failing to close when installed vertically and requested licensees to verify the installation of similar valves to ensure adequate operation. The licensee closed this document with an internal memorandum dated November 17, 1978 which stated in part that "All check valves installed at Nine Mile Point #1 are horizontally installed Chapman Tilting Disc Check Valves." Contrary to this statement, the team noted during plant walkdowns that the Core Spray Topping Pump Discharge Check Valves (81-07, 81-08, 81-27, and 81-28) were installed in the vertical position, along with check valves on the discharge piping of the RBCLC pumps and the condensate booster pumps. Thus, the team concluded that the licensee's review of the concerns of IE Circular 78-15 appeared to be inadequate.

(4) GE SIL 375 addressed concerns with potential water hammer effects caused by inadequacies in the keep-fill subsystems for emergency core cooling (ECCS) systems on BWR-4, 5, and 6 designs. The licensee closed this document with an internal memorandum that noted that the concern was not pertinent to NMP-1 since it was not one of the specified reactor designs. At the top of the file memo was a note indicating that the plant did have a keep-fill subsystem for the core spray system, but no further evaluation was evidently made. The design review conducted as part of this inspection identified in Section 3.1.5 of this report the potential for water hammer during a LOCA because of the location of the injection point for the keep-fill system. The team concluded that an adequate review of the subject document was not made, resulting in the conclusion that the document was not applicable.

(5) The team identified several instances where closure documentation was either not in the file or the closure documentation had notes that indicated the response was not acceptable for closure. Examples of these were GE SIL 300, 323, and 375 and IN 84-37 and 85-76. The licensee had not resolved these discrepancies by the close of the inspection.

(6) At the time of the inspection, the licensee had approximately 336 OEA items remaining open. The licensee had increased its staff with contractors to review each OEA item before startup. This review, however, would not include past responses to industry items.

At the inspection followup meeting, the licensee stated that the inspection team's findings were examples of past practices of industry information review and not indicative of the current program. The team agreed that the current program was not adequately reviewed by the inspection sample, but was concerned that previous responses were not being reviewed. This issue will remain unresolved pending NRC followup review of the licensee's program for evaluating industry information (50-220/88-201-10).

3.8.4 Quality Assurance Program

The inspection team reviewed two quality assurance (QA) functions during the inspection; audits and surveillances. Selected QA audit and surveillance reports for activities similar to the areas covered by the NRC inspection were reviewed by the team to determine whether the licensee's internal QA organization was capable of finding significant technical issues. The specific documents reviewed

are included in Appendix B of this report. The following observations were made by the team during the review:

(1) Recent QA Surveillance Reports have identified significant and credible findings. Two examples were the improper wiring found in the auxiliary control room cabinets during Surveillance SR88-20238 and the improperly performed snubber inspections identified during Surveillance SR88-20351. In each case, the identification of the deficiency allowed the licensee to correct the problem before it was identified by external sources such as a plant event or an NRC inspection.

(2) Past QA Audits for operations, maintenance, surveillance testing, and design modifications appeared to be programmatic and compliance oriented. The audits were limited to verifying that the existing procedure steps were being accomplished and documented properly, but did not verify that the steps were correct for the circumstances in the plant.

Licensee management explained the difference between the QA audit and surveillance programs as a delay in obtaining results from previous QA training. Earlier in 1988, the QA Department had initiated training and hiring to redirect the department to more technical, event-oriented audits and surveillances. The results of this redirection have been evident in the QA Surveillance Program because of the real-time nature of the program. The QA Audit Program had not yet benefited from the redirection in the areas reviewed by the team because audits had not been completed since the improvements were initiated. The team agreed with this conclusion, but was concerned that performance based audits should be completed in key areas to provide the licensee with assurances that quality activities are being adequately performed before plant restart.

4.0 MANAGEMENT EXIT MEETING

On October 17, 1988 an exit meeting was conducted at the site upon the conclusion of the onsite inspection. The licensee representatives at this exit meeting are indicated in Appendix A of this report. Mr. C. J. Haughney, Chief, Special Inspection Branch, NRR; Mr. R. Capra, Chief, Project Directorate I-1, NRR; and Mr. J. Johnson, Chief, Reactor Projects Section 2C, Region I represented NRC management at this meeting. The scope of the inspection was discussed and the licensee was informed that the inspection would continue with further in-office data review and analysis by the team members. The team members presented their findings and responded to licensee questions. The licensee was informed that some of the findings could become potential enforcement findings.

On October 26, 1988 the NRC issued a letter summarizing the significant findings of the inspection for the licensee's restart planning purposes. A meeting was subsequently conducted on November 17, 1988 between the NRC and the licensee to discuss the status of resolution of the findings discussed in the NRC letter. The results of this meeting were documented in an NRC letter of November 23, 1988.

APPENDIX A

Personnel Contacted	Organization
R. Abbott	NMPC Coord. SOER Review and Evaluation
J. Aldrich	NMPC Station Super. Tech Assist.
W. Bandla	NMPC Assistant Operations Supervisor
*P. Bartolini	NMPC Mechanical Design Basis Contact
*C. Beckham	NMPC Mgr. Nuc. QA Ops
K. Belden	NMPC Operations
J. Benzing	NMPC Assistant Maintenance Manager
C. Bessel	NMPC Operations
*L. Blasiak	NMPC Electrical Consultant
F. Borden	NMPC Electrical Maintenance
T. Breigle	NMPC QA
R. Butchington	NMPC Nuclear Inservice Inspector
C. Caltabiano	NMPC Mechanic
C. Cary	NMPC Supervisor Training Nuclear
W. Connally	NMPC QA
W. Cook	NRC Senior Resident Inspector
P. Close	NMPC Maintenance Evaluator
*K. Dahlberg	NMPC Unit 1 Station Superintendent
*J. Dillon	NMPC Supervisor QA Audits
*S. Domago	NMPC Assist. Ops. Supt.
*P. Eddy	NMPC Site Representative
T. Egan	NMPC Engineering
*M. Falise	NMPC Site Mech. Maint. Superintendent
R. Fenton	NMPC Senior QA Technician
C. Fischer	NMPC Elect. Maint. Superintendent
*P. Francisco	NMPC Salina Meadows Team Leader
M. Gasser	NMPC Modification Consultant
*D. Goodney	NMPC Modification Engineer
D. Green	NMPC Core Spray Cognizant Engineer H.
*W. Hansen	NMPC Mgr. Compliance QA
F. Howley	NMPC Asst Supt.- Const. & Maint.
D. Jakubowski	NMPC Battery Engineer
W. James	NMPC Supervisor Inst. and Control
*L. Klosowski	NMPC SSRI Team Leader
T. Kolceski	NMPC Operations
J. Kronenbitter	NMPC Technical Support Engineer
M. Lachut	NMPC Assist. Supervisor Mech. Maint.
C. Lass	NMPC Mechanic
R. Longo	NMPC Supervisor Mech. Maint. Nuclear
A. Loveland	NMPC I&C Engineer
*C. Mangan	NMPC Sr. Vice President, Nuclear
J. Marshall	NMPC Erosion/Corrosion Engineer
*M. Masuicca	NMPC Operations
R. Matteson	NMPC Chief Shift Operator
*P. Mazzaferro	NMPC Technical Support
E. McCaffrey	NMPC NPRDS Coordinator
S. McCoy	NMPC Supervisor of Stations

APPENDIX A - Continued

Personnel Contacted	Organization
G. Montgomery	NMPC QA Surveillance Engineer
*M. Mosier	NMPC HPCI Cognizant Engineer
T. Newman	NMPC Quality Eng. and QC Supervisor
*L. Nowicki	NMPC Electrical Consultant
K. Parlee	NMPC Assistant Mechanical Design Engineer
J. Parrish	NMPC Station Shift Supervisor
N. Patrou	NMPC Operations
D. Pike	NMPC Audits and Reports
J. Porter	NMPC QA Technician
*D. Pracht	NMPC Sr. Nuclear Engineer
*N. Rademacher	NMPC Director of Compliance
M. Randall	NMPC Chief Shift Operator
M. Restani	NMPC Auxiliary Operator B
*T. Roman	NMPC Assist. to Vice President, Nuclear
F. Slye	NMPC QC Lead Unit 1
C. Soucy	NMPC Supervisor Training Nuclear
J. Spadafore	NMPC Site Appendix J Test Engineer
*R. Strusinski	NMPC Operations
*C. Terry	NMPC V.P. Nuclear Eng. and Licensing
R. Tessier	NMPC Outage Manager
L. Wambsgan	NMPC QA
G. Whitaker	NMPC Generation Engineer, Mechanical
P. Wilde	NMPC QA Surveillance Group Superintendent
*J. Willis	NMPC General Superintendent
P. Wolfe	NMPC Licensing Engineer
*T. Wood	NMPC Training
*A. Zallnick	NMPC Assist. to Senior Vice President, Nuclear

*Attended exit meeting on October 7, 1988.

APPENDIX B

Documents Reviewed

1. Electrical and Mechanical Design Documents:

125 VDC-Batt11ES	"Battery Sizing Calc - 59 Cells," Revision 1, (April 21, 1988)
125 VDC-Batt12ES	"Battery Sizing Calc - No spare capacity," Revision 0, (July 21, 1988)
125 VDC PB-16 LF/VD	"Power Board 16 Feeder Cable Voltage Drop," Revision 0, (July 21, 1988)
120 VAC-RPS11 Fuse 11	"Reactor Core Spray Instrumentation Circuit Loading," Revision 0, (July 20, 1988)
125 VDC-Train 11 FS	"Battery 11 Fault Current," Revision 0, (September 20, 1988)
DC System Study	"125 VDC Circuit Breaker Coordination Study," (February 28, 1983)
600 V System Study	"600 VAC Circuit Breaker Coordination Study," (July 11, 1969)
4160 V/115kV System Study	"Overcurrent Relay Coordination for Power Boards 11/12 and 101, 102, 103," (July 20, 1969)
Fault Study	"4160 V Power Board Relay Settings," (June 14, 1965)
Relay Setting	"4160 V Power Board Relay Settings," (May/June 87)
Load Study	"Power Distribution Load Study and Test Data," (December 10, 1981)
Specification E-1241	"Technical Requirements for the Rewind and Repair of Motors at NMP 1," (July 1, 1986)
Work Requests	WR 111270, 014032, 010566, 035337,
Maintenance Procedures	N1-EPM-GEN-4Y182, N1-EPM-GEN-R120
Surveillance Procedures	N1-ESP-SB-W276, N1-ESP-SB-R277, N1-ESP-SB-4Y272, N1-ST-R2, N1-ST-R2
Pump Motor Data Sheets	GE 205-61245 #2(FWBP), RT 224657(FWP), RT MSJ 540(CSP), GE 309-90846-2(CSTP)
VTP 17964-67	"Core Spray Pump Performance (BHP vs Flow)," (March 13, 1968)

P-450105	"Core Spray Topping Pump Performance (BHP vs Flow)," (March 7, 1968)
Test Data	"Test of HPCI System at NMP1 with Power From Bennett's Bridge," (June 27, 1974)
C-35843-C	"Reactor Vessel Inst. Level Ranges, Actuation Points, and Water Volumes," Rev. 1, (July 24, 1985)
File Code NMP27205	"Memo, Whitaker to Smith re Core Spray System Pressure Relief Valves," (August 5, 1987)
Pump Curves	VRP-17964-67(CSP), P-450105(CSTP), P-443811(CP) P-443812(FWBP), E-206541(FWP)
BB31005-74-11	"Flexible Ball Joint," Rev. C, (August 3, 1966)
Unnumbered Calc.	"Starting Feedwater Booster Pump from Bennett's Bridge," (Not dated)
Unnumbered Calc.	"Starting Feedwater Pump from Bennett's Bridge," (Not dated)
Unnumbered Calc.	"Calculation of Core Spray System Head Loss," (1/9/67) NMP-1 Core Spray System Response to NRC SSFI Questions (Complete package including references prepared by MPR Associates, Inc.)," (September 29, 1988)
Unnumbered Calc.	"High Pressure Coolant Injection Response to NRC SSFI Questions (Complete package including references prepared by MPR Associates, Inc.)," (October 3, 1988)
Unnumbered Calc.	"MPR Calc., Core Spray Flow Rate vs. Reactor Vessel Pressure," (September 16, 1988)
Unnumbered Calc.	"MPR Calc., Core Spray System-Flow vs. Delivery Pressure," (July 13, 1982)
Unnumbered Calc.	"MPR Calc., Core Spray System Flow Calculations," (November 4, 1982)
Unnumbered Calc.	"MPR ltr., McCurdy to Greene re Core Spray System Characteristics," (November 17, 1982)
Unnumbered Calc.	"GE ltr., Aaugello to Tetley re LOCA Program Phase III," (April 22, 1987)
Unnumbered Calc.	"NMPC ltr., Tetley to Augello, response to above GE ltr.," (May 4, 1988)
NEDC-31446P Class III	"Nine Mile Point Unit One Safer/Corecool/Gestr-LOCA LOCA Analysis (GE)," (June 1987)

Unnumbered Calc.	"Calc. of Cond. & FW System Flow Resistance," (November 10, 1964)
Req. 309-90800	"Feedwater Control System Design Criteria," (July 1, 1964)
22A1350	"Core Spray System Design Specification," Rev. 0, (April 12, 1968)
System Description 20	"Cond. and FW Systems Function Spec. and Design Criteria"

2. Testing Procedures

N1-ISI-FUN-307	"Core Spray Functional Pressure Test," Rev. 0
N1-ISI-HYD-81/81.1/93.1	"Reactor Core Spray System Hydrostatic Pressure Test," Rev. 3
N1-ISI-HYD-424	"Reactor Core Spray System Hydrostatic Pressure Test," Rev. 0 and 1
N1-ISI-INS-203	"Feedwater Inservice Pressure Test," Rev. 0
N1-ISP-R-031-502	"Reactor Containment Isoolation Valve Leak Rate Test," Rev. 0
N1-ISP-R-040-501	"Type 'C' Containment Isolation Leak Rate Test Core Spray High Point Vent Valves," Rev. 0
N1-ISP-R-058-501	"Type "C" Containment Isolation Leak Rate Test Torus Water Makeup Flange," Rev. 0
N1-ISP-R-093-501	"Type 'C' Containment Isolation Leak Rate Test Raw Water Intertie To Core Spray Valves," Rev. 0
N1-ISP-R-201-514	"Type "B" Double Gasketed Seals Leak Rate Test Core Spray Flex Ball Joint Flange"
N1-ISP-24.7	"Core Spray System Check Valves Keep-Fill System Leak Rate Test," Rev. 1 and 2
N1-ST-C3	"Automatic Start-up of High Presseure Coolant Injection System," Rev. 4
N1-ST-IC3	"Core Spray Redundant Component or System Operability Test," Rev. 3
N1-ST-IC5	"High Pressure Coolant Injection Surveillance with Inoperable Component Test," Rev. 4
N1-ST-Q1	"Core Spray Pumps and Motor Operated Valves Operability Test," Rev. 2

N1-ST-Q3	"High Pressure Coolant Injection Pump and Valve Operability Test," Rev. 3
N1-ST-R9	"Core Spray System Operability Using Demineralized (C.S.T.) Water," Rev. 6
N1-ST-V10	"Core Spray System Check Valves Leakage Test," Rev. 0

3. Maintenance Procedures and Documentation

N1-MSP-GEN-V353	"Snubber Visual Inspection," Rev. 1
Administrative Procedures	AP-5.0, AP-8.1
Maintenance Instructions	S-MI-GEN-004, S-MI-GEN-003, S-MI-GEN-002
Maintenance Procedures	N1-NMP-81-501, N1-ISP-M-036-005, N1-MPM-29-R126 N1-EMP-81E-201, N1-NMP-31-210, N1-NMP-51-108 N1-NMP-29-209, N1-NMP 29-211.2, N1-NMP-29-211.1 N1-NMP-30-248, N1-NMP-81-112, N1-NMP-81-113
Training Procedures	NTP-9, NTP-3, NTP-7

4. Operations Procedures and Documentation

N1-ICP-C-49	"Condensate Hotwell Level," Rev. 6
S-SUP-Q6	"Control of Operator Aids," Rev. 0
N1-ST-SO	"Shift Checks," Rev. 14
N1-ST-DO	"Daily Checks," Rev. 17
Station Guides	"Operators Rounds Guides"
Station Instructions	"Station Shift Supervisor Instructions"
OJT Manual	"Non-Licensed Reactor Operator Candidate OJT Manual, System 209, Core Spray System," Rev. 0
OJT Manual	"Non-Licensed Reactor Operator Candidate OJT Manual, System 206, High Pressure Coolant Injection System," Rev. 0
Administrative Procedures	AP-3.4.2, AP-4.0, AP-3.3.1, AP-4.1,
Maintenance Procedures	N1-IMP-209-J, N1-PM-Q3, N1-PM-Q5

Operating Procedures	N1-OP-2, N1-SOP-5, N1-OP-15A, N1-OP-15b, N1-OP-16, N1-OP-20, N1-OP-30, N1-OP-33A, N1-OP-43, N1-OP-45, N1-OP-46, N1-OP-47A, N1-SOP-6
EOP-1 thru EOP-10	"Emergency Operating Procedures," (5/12/88)

5. Quality Assurance Procedures and Documents

QAP 15.01	"Control of Nonconforming Items," Rev. 5
Work Requests	WR 127355, WR 131849

QA Surveillance Reports:

SK-88-20270, SK-88-20308, SK-88-20238, SK-88-20271, SK-88-20351, SK-88-20296, SK-88-20297, SK-88-20247, SK-88-20381, SK-88-20366, SK-88-20259

QA Audit Reports:

#87025-RG/IN, #SY-RG-IN-86012, NM-RG-IN-86021, NM-RG-IN-87006, SY-RG-IN-86015, SY-RG--86012, RG-IN-87025, SY-RG-IN-87007, SY-RG-IN-87025, SY-RG-IN-88003

Nonconformance Reports:

NCR 1-87-0027, NCR 1-87-0061, NCR 1-88-0004, NCR 1-88-0003, NCR 1-88-0005, NCR 1-88-0006, NCR 1-88-0008

Corrective Action Requests	88-2030, 88-2033
Occurrence Report 87-326	"Core Spray System Loop 12 Inoperability Due to Weld Reapir of Valve 40-03"

6. Safety Evaluations

Evaluation Number	Title	Modification
86-005	Diesel Generator Upgrade	N1-82-92
86-013	Fixes from Detailed Control Room Design Review	83-58-2
86-016 Rev 1	Rerouting of the Core Spray System Control Cables	85-108
86-059	Local Leak Rate Testing of Feedwater Isolation Check Valves Use of 100 psi Air to Simulate Reverse FLow	NA
87-016	DCRDR Phase II	86-43

87-029 Rev 1	ATWS - Increased Liquid Poison Injection Capability	
88-003 Rev 1	Emergency Generators' Diesel Fuel Storage Tank Replacement	87-066
88-009 Rev	Analysis of Lost Part in Feedwater System	NA
88-013	Reflect the Nuclear Division Organization as of May 31, 1988	NA

APPENDIX C

Unresolved Items

Number	Description	Report Section
01	10 CFR 50.46 Technical Specification Amendment	3.1.1
02	Core Spray System Design Deficiencies	
	(a) System Performance Curves	3.1.2
	(b) Net Positive Suction Head Analysis	3.1.3
	(c) Succeptibility to Water Hammer	3.1.5
	(d) Adequacy of Alarm Setpoints	3.1.6
	(e) Control Room Flow Indication	3.1.7
03	HPCI/FW System Design Deficiencies	3.2.1
04	Design Documentation Deficiencies	3.4.2
05	EOP Deficiencies	3.5.1
06	Operator Aids and Procedures Deficiencies	3.5.5
07	Core Spray System Testing	3.7.1
08	HPCI/FW System Testing	3.7.2
09	Corrective Actions and NRC Reportability	3.8.1 and 3.8.2
10	Operational Experience Assessment Program	3.8.3

07-616.91

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

NRC INSPECTION MANUAL

SPLB

INSPECTION PROCEDURE 71500

BALANCE OF PLANT INSPECTION

PROGRAM APPLICABILITY: 2515, 2525

71500-01 INSPECTION OBJECTIVES

01.01 To verify the effectiveness of the preventive and corrective maintenance programs for BOP systems.

01.02 To determine the adequacy of modifications made to the BOP systems.

01.03 To determine the adequacy of BOP operating procedures.

01.04 To determine the effectiveness of management attention to the correction of BOP problems.

01.05 To determine the adequacy of the licensee's root cause analysis.

71500-02 INSPECTION REQUIREMENTS

Perform all or portions of these inspection requirements as appropriate to the specific inspection(s).

02.01 Maintenance. Review the maintenance program and related documents such as completed work requests, for the BOP system to verify that:

a. Equipment failures in the BOP system are evaluated for input into the preventive and corrective maintenance programs.

b. The preventive maintenance (PM) program for the BOP system is adequate for ensuring system or component reliability, and that

1. PM recommendations from vendor or manufacturer equipment manuals for the installed equipment are included in the program, are correctly reflected in the maintenance procedures, and are based on vendor or manufacturer documents. If recommendations were not included or were not implemented by the licensee, determine whether justifications for deviating from the recommendations were documented and technically sound.

2. Vendor service trip reports that were published as a followup to

04

equipment failures or servicing are reviewed and considered for action by the licensee. If recommendations were not implemented or were modified by the licensee, determine whether justification for deviating from the recommendations was documented and technically sound.

3. Corrective maintenance is documented in maintenance history records, appropriately trended, and analyzed.

4. PM program includes appropriate periodic calibration and testing of protective instruments and controllers.

c. Approved procedures were used for all nonroutine work activities, including, as a minimum, those which are sufficiently difficult as to require craft skills training.

d. Replacement parts and materials are procured to at least the same quality as the original parts.

e. Post-maintenance testing or inspection is specified, is correct for the maintenance being performed, and is completed before returning the system or component to service. Testing should demonstrate that the system or component is operable and that it meets the design baseline requirements.

f. Measuring and test equipment used to conduct maintenance is within its calibration cycle.

g. Personnel who perform maintenance activities are appropriately trained and qualified for the work, are familiar with and use the applicable procedures, and coordinate work with operations personnel.

02.02 Modifications. Review system or component modifications (inspector should obtain a listing of past and ongoing modifications in order to select a sample of modifications for a more detailed review.) and verify that:

a. The modified systems and components are designed, constructed, and tested in accordance with appropriate portions of codes and standards that are equal to those used for the original systems or components.

b. Post-modification testing is adequate to demonstrate that the modified system or component meets its functional requirements.

c. Operating procedures, preventive maintenance programs, operator training programs, and as-built drawings are revised before the modification is declared operable.

d. System or component designs are considered for modification if the licensee is experiencing repeated failures of the component or part. Additionally, the system, component or part should be considered for modification if its lack of redundancy is such that a single spurious signal will cause a plant trip (e.g., one-out-of-one trip logic for the feed pump or main turbine).

e. The interfaces among engineering, QA, and plant organizations are well

defined and functional, and communications flow easily among the organizations.

f. Design changes are reviewed and approved in accordance with technical specifications and established QA/QC controls, and are consistent with the original design bases.

g. Safety evaluations pursuant to 10 CFR 50.59 are performed for those modifications that require a change to the system or component description in the FSAR and that these evaluations are technically adequate.

02.03 Operations. Review various plant procedures and technical documents to ensure that:

a. Operating and abnormal operating procedures for the system are:

1. consistent with the as-built drawings for the system and, if appropriate, reflect recent modifications to the system and

2. located in the control room and other applicable plant areas and are controlled, current, and approved for use.

b. Component operating positions as noted during a walkdown of the system are consistent with the "as left" positions documented in the most recently performed system lineup.

c. Operators are knowledgeable in the implementation of system operating and emergency procedures, especially with respect to recent modifications that changed the operating characteristics of the system.

d. General condition of equipment (e.g., no excess corrosion, no evidence of steam, water, oil leaks, no other significant deficiencies) is adequate to assure its operability.

e. A BOP system corrosion detection and control program is being implemented when used by the licensee.

02.04 Management Support. Review various licensee programs and management responses to various inspection reports and industry initiatives to ensure that:

a. Management is responsive to self-identified BOP problems, those identified by NRC inspectors, and those identified in IE Notices, inspection reports, SALP reports, etc.

b. Management is successful in reducing the number and frequency of plant trips initiated or complicated by BOP problems.

c. The licensee is participating in industry initiatives (NUMARC, EPRI, owners groups, etc.) that address BOP problems and solutions.

d. Adequate resources are allocated for identifying and solving BOP component or system problems.

02.05 Root Cause. Review plant operating and maintenance history for the past 2-years and interview key plant personnel to determine BOP system components that have a history of unreliability or that have caused or complicated recovery from plant trips and transients. If possible, select at least four components or events for further analysis and:

a. Determine the root cause for each component failure or event selected above by reviewing the licensee's root cause analysis, if performed. The root cause analysis should implicate broad programmatic areas such as maintenance, operator training, etc. that are contributors to the component failure or event, and that are in need of upgrade.

b. Assess the adequacy and timeliness of the corrective action taken by the licensee relative to preventing recurrence of the events or component failures selected in section 02.01a for review.

71500-03 INSPECTION GUIDANCE

The balance of plant inspection procedure is written for a detailed in-depth team inspection approach examining licensee's programs such as maintenance, modifications and design, operations, and corrective actions. The inspection should be prefaced with a "bagman" trip during which the team leader gathers inspection material for review and as part of a preparation effort prior to actually beginning the inspection. Although this IP is written for a team inspection approach, portions of the IP can be selected to focus on particular BOP issues that may affect a particular plant. Such reduced-scope inspections can be accomplished by a smaller team, or an individual inspector as appropriate.

Recent NRC and industry reports analyzing unplanned reactor shutdowns (plant trips) have demonstrated that many plant trips were caused by failures of BOP systems and components. The safety significance of BOP failures can be related to two aspects of challenges to reactor safety. The first concerns challenges to reactor safety systems caused by a BOP failure, such as failure of a feedwater regulating valve or a loss of a main feedwater pump. The second concerns BOP failures that hinder the ability of operators and safety systems to control the reactor, given that a challenge to a safety system has already occurred. An example of this would be the failure of turbine bypass valves which could complicate recovery during a plant transient. Therefore, increased challenges to safety systems from the BOP systems, cause unnecessary challenges to the safety related systems which, if they were to fail, could cause reactor core damage.

The importance of increased attention to BOP equipment was emphasized in a November 1985 memorandum from the EDO concerning lessons learned from the June 9, 1985 loss of feedwater event at Davis-Besse. The growing emphasis on BOP systems is also highlighted by SECY-86-164, wherein the staff made recommendations to the Commission for clarifying the scope of structures, systems, and components that should be classified as "important to safety."

The feedwater system has been the focus of some recent studies because it has been the system most responsible for unplanned reactor trips from above 15% power during 1984 and 1985. Additionally, this system also has been a significant contributor to plant risk in many plants' PRAs.

Although this IP does not have a specific regulatory basis, it does have a safety orientation because of the challenges BOP systems can have on safety-related systems and the safe operations of the plant. Therefore consistent with the objective of the operating reactor inspection program, the purpose of this inspection is to focus on safety. The intent of this IP is to justify to the licensee concerns about design, modification, maintenance, operations, and testing practices for BOP systems and components. If the inspection team considers that a particular plant is experiencing BOP system problems that are contributing to plant trips or complicating plant recovery, the inspection team should research licensee system documentation and interview key plant personnel to determine specific system components that display a history of unreliability or have caused plant trips and transients.

03.01 Inspection Requirement 02.01.a. The licensee should have a program which will identify repeated component or equipment problems so that appropriate reviews will be performed to investigate the root cause of repeated maintenance. The resolution to these maintenance problems could involve design changes, increased preventive maintenance on the equipment, or improved maintenance procedures. The overall intent of such programs is to be able to identify equipment or component problems that are causing the system to be less reliable so that appropriate corrective actions can be taken as soon as possible.

03.02 Inspection Requirement 02.01.b1. Typically, not all vendor recommended preventive maintenance items will be incorporated into the licensee's program nor it that necessary in order to have a good preventive maintenance program. However, the licensee should be able to justify why recommended vendor maintenance items were not incorporated into the program for those items which have a high failure rate.

03.03 Inspection Requirement 02.01.c. Procedures should be written by personnel familiar with the equipment or system. In any event, the inspector should ensure that the maintenance performed is adequate by reviewing vendor recommended procedures or other technical documents.

03.04 Inspection Requirement 02.01.e. Post-maintenance testing should ensure that not only does the component or equipment operate as originally designed but that its interaction within the system is satisfactory. For example, if a feedwater regulating valve was replaced, then the licensee must ensure that, not only does it operate satisfactorily mechanically, but also that its control features, as required by the feedwater control system, are satisfactory.

03.05 Inspection Requirement 02.02. The number of BOP system modifications selected should be large enough such that the inspector is able to select a modification which involves system hardware change or system hardware reconfiguration. If appropriate, the inspector should also review the adequacy of the 50.59 review performed by the licensee.

03.06 Inspection Requirement 02.02.a. Codes and standards to which licensees are committed for the design, construction, and testing of the BOP systems are stated in appropriate sections of the FSAR and system design documents. In Code states, licensees must meet the ASME Code rules for design, construction, and testing of BOP systems. The utility also may elect

to adopt or utilize appropriate portions of other non-nuclear codes and standards; the extent to which this is the case should be determined.

03.07 Inspection Requirement 02.02.f. This area should be reviewed by an inspector with design experience. The review may necessitate that the inspector be at a location other than the site in order to review the design documents for the original design requirements. The level of review should be detailed if preliminary calculations cause the inspector to doubt the validity of the licensee's calculations based on his knowledge of the system or his own experience. If the licensee's calculations are in doubt, the inspector should reevaluate the calculations and determine the safety significance of the calculation error to the system and the plant.

03.08 Inspection Requirement 02.02g. Modifications made to the BOP system or components, or to related support systems, could possibly decrease reliability and increase the frequency of unplanned trips. If the modifications reviewed are implicated as contributing to or causing problems that resulted in challenges to safety systems, the impact should have been considered by the licensee in the 10 CFR 50.59 safety evaluation.

03.09 Inspection Requirement 02.03b. Walkdowns should not only verify that the actual system configuration is consistent with the latest valve line-up, but also that the actual system configuration will function as designed with all the system modifications in effect. To this end, the inspection team needs to verify that the system configurations are consistent with the latest system designs.

03.10 Inspection Requirement 02.04a. Developing issues with respect to BOP and presenting these to the licensee requires a different approach than for safety-related systems because of a shortage of prescriptive requirements. The basis for addressing BOP issues with licensees is that an aggressive, safety-conscious management approach will not be limited solely to safety-related hardware but will be reasonably applied to BOP systems that may cause challenges to safety systems at a relatively high frequency. When the licensee's programs do not conform to reasonable practices the inspection team should inform the licensee that implementation of these practices has the potential for increasing BOP system or component reliability and decreasing safety system challenges.

03.11 Inspection Requirement 02.05b. Responsiveness to the team's findings, the adequacy of the planned corrective actions indicate the licensee's commitment to safety in a non-safety system. The inspection team should review the licensee's plans for addressing identified BOP problems in terms of analyzing, defining, planning, scheduling, implementing, tracking, and reporting problems and their solutions. The licensee should have considered the generic applicability of the problem in determining corrective actions.

END

07-616-91

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

NRC INSPECTION MANUAL

SPLB

INSPECTION PROCEDURE 71500

BALANCE OF PLANT INSPECTION

PROGRAM APPLICABILITY: 2515, 2525

71500-01 INSPECTION OBJECTIVES

01.01 To verify the effectiveness of the preventive and corrective maintenance programs for BOP systems.

01.02 To determine the adequacy of modifications made to the BOP systems.

01.03 To determine the adequacy of BOP operating procedures.

01.04 To determine the effectiveness of management attention to the correction of BOP problems.

01.05 To determine the adequacy of the licensee's root cause analysis.

71500-02 INSPECTION REQUIREMENTS

Perform all or portions of these inspection requirements as appropriate to the specific inspection(s).

02.01 Maintenance. Review the maintenance program and related documents such as completed work requests, for the BOP system to verify that:

a. Equipment failures in the BOP system are evaluated for input into the preventive and corrective maintenance programs.

b. The preventive maintenance (PM) program for the BOP system is adequate for ensuring system or component reliability, and that

1. PM recommendations from vendor or manufacturer equipment manuals for the installed equipment are included in the program, are correctly reflected in the maintenance procedures, and are based on vendor or manufacturer documents. If recommendations were not included or were not implemented by the licensee, determine whether justifications for deviating from the recommendations were documented and technically sound.

2. Vendor service trip reports that were published as a followup to

equipment failures or servicing are reviewed and considered for action by the licensee. If recommendations were not implemented or were modified by the licensee, determine whether justification for deviating from the recommendations was documented and technically sound.

3. Corrective maintenance is documented in maintenance history records, appropriately trended, and analyzed.

4. PM program includes appropriate periodic calibration and testing of protective instruments and controllers.

c. Approved procedures were used for all nonroutine work activities, including, as a minimum, those which are sufficiently difficult as to require craft skills training.

d. Replacement parts and materials are procured to at least the same quality as the original parts.

e. Post-maintenance testing or inspection is specified, is correct for the maintenance being performed, and is completed before returning the system or component to service. Testing should demonstrate that the system or component is operable and that it meets the design baseline requirements.

f. Measuring and test equipment used to conduct maintenance is within its calibration cycle.

g. Personnel who perform maintenance activities are appropriately trained and qualified for the work, are familiar with and use the applicable procedures, and coordinate work with operations personnel.

02.02 Modifications. Review system or component modifications (inspector should obtain a listing of past and ongoing modifications in order to select a sample of modifications for a more detailed review.) and verify that:

a. The modified systems and components are designed, constructed, and tested in accordance with appropriate portions of codes and standards that are equal to those used for the original systems or components.

b. Post-modification testing is adequate to demonstrate that the modified system or component meets its functional requirements.

c. Operating procedures, preventive maintenance programs, operator training programs, and as-built drawings are revised before the modification is declared operable.

d. System or component designs are considered for modification if the licensee is experiencing repeated failures of the component or part. Additionally, the system, component or part should be considered for modification if its lack of redundancy is such that a single spurious signal will cause a plant trip (e.g., one-out-of-one trip logic for the feed pump or main turbine).

e. The interfaces among engineering, QA, and plant organizations are well

defined and functional, and communications flow easily among the organizations.

f. Design changes are reviewed and approved in accordance with technical specifications and established QA/QC controls, and are consistent with the original design bases.

g. Safety evaluations pursuant to 10 CFR 50.59 are performed for those modifications that require a change to the system or component description in the FSAR and that these evaluations are technically adequate.

02.03 Operations. Review various plant procedures and technical documents to ensure that:

a. Operating and abnormal operating procedures for the system are:

1. consistent with the as-built drawings for the system and, if appropriate, reflect recent modifications to the system and

2. located in the control room and other applicable plant areas and are controlled, current, and approved for use.

b. Component operating positions as noted during a walkdown of the system are consistent with the "as left" positions documented in the most recently performed system lineup.

c. Operators are knowledgeable in the implementation of system operating and emergency procedures, especially with respect to recent modifications that changed the operating characteristics of the system.

d. General condition of equipment (e.g., no excess corrosion, no evidence of steam, water, oil leaks, no other significant deficiencies) is adequate to assure its operability.

e. A BOP system corrosion detection and control program is being implemented when used by the licensee.

02.04 Management Support. Review various licensee programs and management responses to various inspection reports and industry initiatives to ensure that:

a. Management is responsive to self-identified BOP problems, those identified by NRC inspectors, and those identified in IE Notices, inspection reports, SALP reports, etc.

b. Management is successful in reducing the number and frequency of plant trips initiated or complicated by BOP problems.

c. The licensee is participating in industry initiatives (NUMARC, EPRI, owners groups, etc.) that address BOP problems and solutions.

d. Adequate resources are allocated for identifying and solving BOP component or system problems.

02.05 Root Cause. Review plant operating and maintenance history for the past 2-years and interview key plant personnel to determine BOP system components that have a history of unreliability or that have caused or complicated recovery from plant trips and transients. If possible, select at least four components or events for further analysis and:

a. Determine the root cause for each component failure or event selected above by reviewing the licensee's root cause analysis, if performed. The root cause analysis should implicate broad programmatic areas such as maintenance, operator training, etc. that are contributors to the component failure or event, and that are in need of upgrade.

b. Assess the adequacy and timeliness of the corrective action taken by the licensee relative to preventing recurrence of the events or component failures selected in section 02.01a for review.

71500-03 INSPECTION GUIDANCE

The balance of plant inspection procedure is written for a detailed in-depth team inspection approach examining licensee's programs such as maintenance, modifications and design, operations, and corrective actions. The inspection should be prefaced with a "bagman" trip during which the team leader gathers inspection material for review and as part of a preparation effort prior to actually beginning the inspection. Although this IP is written for a team inspection approach, portions of the IP can be selected to focus on particular BOP issues that may affect a particular plant. Such reduced-scope inspections can be accomplished by a smaller team, or an individual inspector as appropriate.

Recent NRC and industry reports analyzing unplanned reactor shutdowns (plant trips) have demonstrated that many plant trips were caused by failures of BOP systems and components. The safety significance of BOP failures can be related to two aspects of challenges to reactor safety. The first concerns challenges to reactor safety systems caused by a BOP failure, such as failure of a feedwater regulating valve or a loss of a main feedwater pump. The second concerns BOP failures that hinder the ability of operators and safety systems to control the reactor, given that a challenge to a safety system has already occurred. An example of this would be the failure of turbine bypass valves which could complicate recovery during a plant transient. Therefore, increased challenges to safety systems from the BOP systems, cause unnecessary challenges to the safety related systems which, if they were to fail, could cause reactor core damage.

The importance of increased attention to BOP equipment was emphasized in a November 1985 memorandum from the EDO concerning lessons learned from the June 9, 1985 loss of feedwater event at Davis-Besse. The growing emphasis on BOP systems is also highlighted by SECY-86-164, wherein the staff made recommendations to the Commission for clarifying the scope of structures, systems, and components that should be classified as "important to safety."

The feedwater system has been the focus of some recent studies because it has been the system most responsible for unplanned reactor trips from above 15% power during 1984 and 1985. Additionally, this system also has been a significant contributor to plant risk in many plants' PRAs.

Although this IP does not have a specific regulatory basis, it does have a safety orientation because of the challenges BOP systems can have on safety-related systems and the safe operations of the plant. Therefore consistent with the objective of the operating reactor inspection program, the purpose of this inspection is to focus on safety. The intent of this IP is to justify to the licensee concerns about design, modification, maintenance, operations, and testing practices for BOP systems and components. If the inspection team considers that a particular plant is experiencing BOP system problems that are contributing to plant trips or complicating plant recovery, the inspection team should research licensee system documentation and interview key plant personnel to determine specific system components that display a history of unreliability or have caused plant trips and transients.

03.01 Inspection Requirement 02.01.a. The licensee should have a program which will identify repeated component or equipment problems so that appropriate reviews will be performed to investigate the root cause of repeated maintenance. The resolution to these maintenance problems could involve design changes, increased preventive maintenance on the equipment, or improved maintenance procedures. The overall intent of such programs is to be able to identify equipment or component problems that are causing the system to be less reliable so that appropriate corrective actions can be taken as soon as possible.

03.02 Inspection Requirement 02.01.b1. Typically, not all vendor recommended preventive maintenance items will be incorporated into the licensee's program nor it that necessary in order to have a good preventive maintenance program. However, the licensee should be able to justify why recommended vendor maintenance items were not incorporated into the program for those items which have a high failure rate.

03.03 Inspection Requirement 02.01.c. Procedures should be written by personnel familiar with the equipment or system. In any event, the inspector should ensure that the maintenance performed is adequate by reviewing vendor recommended procedures or other technical documents.

03.04 Inspection Requirement 02.01.e. Post-maintenance testing should ensure that not only does the component or equipment operate as originally designed but that its interaction within the system is satisfactory. For example, if a feedwater regulating valve was replaced, then the licensee must ensure that, not only does it operate satisfactorily mechanically, but also that its control features, as required by the feedwater control system, are satisfactory.

03.05 Inspection Requirement 02.02. The number of BOP system modifications selected should be large enough such that the inspector is able to select a modification which involves system hardware change or system hardware reconfiguration. If appropriate, the inspector should also review the adequacy of the 50.59 review performed by the licensee.

03.06 Inspection Requirement 02.02.a. Codes and standards to which licensees are committed for the design, construction, and testing of the BOP systems are stated in appropriate sections of the FSAR and system design documents. In Code states, licensees must meet the ASME Code rules for design, construction, and testing of BOP systems. The utility also may elect

to adopt or utilize appropriate portions of other non-nuclear codes and standards; the extent to which this is the case should be determined.

03.07 Inspection Requirement 02.02.f. This area should be reviewed by an inspector with design experience. The review may necessitate that the inspector be at a location other than the site in order to review the design documents for the original design requirements. The level of review should be detailed if preliminary calculations cause the inspector to doubt the validity of the licensee's calculations based on his knowledge of the system or his own experience. If the licensee's calculations are in doubt, the inspector should reevaluate the calculations and determine the safety significance of the calculation error to the system and the plant.

03.08 Inspection Requirement 02.02g. Modifications made to the BOP system or components, or to related support systems, could possibly decrease reliability and increase the frequency of unplanned trips. If the modifications reviewed are implicated as contributing to or causing problems that resulted in challenges to safety systems, the impact should have been considered by the licensee in the 10 CFR 50.59 safety evaluation.

03.09 Inspection Requirement 02.03b. Walkdowns should not only verify that the actual system configuration is consistent with the latest valve line-up, but also that the actual system configuration will function as designed with all the system modifications in effect. To this end, the inspection team needs to verify that the system configurations are consistent with the latest system designs.

03.10 Inspection Requirement 02.04a. Developing issues with respect to BOP and presenting these to the licensee requires a different approach than for safety-related systems because of a shortage of prescriptive requirements. The basis for addressing BOP issues with licensees is that an aggressive, safety-conscious management approach will not be limited solely to safety-related hardware but will be reasonably applied to BOP systems that may cause challenges to safety systems at a relatively high frequency. When the licensee's programs do not conform to reasonable practices the inspection team should inform the licensee that implementation of these practices has the potential for increasing BOP system or component reliability and decreasing safety system challenges.

03.11 Inspection Requirement 02.05b. Responsiveness to the team's findings, the adequacy of the planned corrective actions indicate the licensee's commitment to safety in a non-safety system. The inspection team should review the licensee's plans for addressing identified BOP problems in terms of analyzing, defining, planning, scheduling, implementing, tracking, and reporting problems and their solutions. The licensee should have considered the generic applicability of the problem in determining corrective actions.

END

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NRC INSPECTION MANUAL

SPLB

INSPECTION PROCEDURE 71500

BALANCE OF PLANT INSPECTION

PROGRAM APPLICABILITY: 2515, 2525

71500-01 INSPECTION OBJECTIVES

01.01 To verify the effectiveness of the preventive and corrective maintenance programs for BOP systems.

01.02 To determine the adequacy of modifications made to the BOP systems.

01.03 To determine the adequacy of BOP operating procedures.

01.04 To determine the effectiveness of management attention to the correction of BOP problems.

01.05 To determine the adequacy of the licensee's root cause analysis.

71500-02 INSPECTION REQUIREMENTS

Perform all or portions of these inspection requirements as appropriate to the specific inspection(s).

02.01 Maintenance. Review the maintenance program and related documents such as completed work requests, for the BOP system to verify that:

a. Equipment failures in the BOP system are evaluated for input into the preventive and corrective maintenance programs.

b. The preventive maintenance (PM) program for the BOP system is adequate for ensuring system or component reliability, and that

1. PM recommendations from vendor or manufacturer equipment manuals for the installed equipment are included in the program, are correctly reflected in the maintenance procedures, and are based on vendor or manufacturer documents. If recommendations were not included or were not implemented by the licensee, determine whether justifications for deviating from the recommendations were documented and technically sound.

2. Vendor service trip reports that were published as a followup to

equipment failures or servicing are reviewed and considered for action by the licensee. If recommendations were not implemented or were modified by the licensee, determine whether justification for deviating from the recommendations was documented and technically sound.

3. Corrective maintenance is documented in maintenance history records, appropriately trended, and analyzed.

4. PM program includes appropriate periodic calibration and testing of protective instruments and controllers.

c. Approved procedures were used for all nonroutine work activities, including, as a minimum, those which are sufficiently difficult as to require craft skills training.

d. Replacement parts and materials are procured to at least the same quality as the original parts.

e. Post-maintenance testing or inspection is specified, is correct for the maintenance being performed, and is completed before returning the system or component to service. Testing should demonstrate that the system or component is operable and that it meets the design baseline requirements.

f. Measuring and test equipment used to conduct maintenance is within its calibration cycle.

g. Personnel who perform maintenance activities are appropriately trained and qualified for the work, are familiar with and use the applicable procedures, and coordinate work with operations personnel.

02.02 Modifications. Review system or component modifications (inspector should obtain a listing of past and ongoing modifications in order to select a sample of modifications for a more detailed review.) and verify that:

a. The modified systems and components are designed, constructed, and tested in accordance with appropriate portions of codes and standards that are equal to those used for the original systems or components.

b. Post-modification testing is adequate to demonstrate that the modified system or component meets its functional requirements.

c. Operating procedures, preventive maintenance programs, operator training programs, and as-built drawings are revised before the modification is declared operable.

d. System or component designs are considered for modification if the licensee is experiencing repeated failures of the component or part. Additionally, the system, component or part should be considered for modification if its lack of redundancy is such that a single spurious signal will cause a plant trip (e.g., one-out-of-one trip logic for the feed pump or main turbine).

e. The interfaces among engineering, QA, and plant organizations are well

defined and functional, and communications flow easily among the organizations.

f. Design changes are reviewed and approved in accordance with technical specifications and established QA/QC controls, and are consistent with the original design bases.

g. Safety evaluations pursuant to 10 CFR 50.59 are performed for those modifications that require a change to the system or component description in the FSAR and that these evaluations are technically adequate.

02.03 Operations. Review various plant procedures and technical documents to ensure that:

a. Operating and abnormal operating procedures for the system are:

1. consistent with the as-built drawings for the system and, if appropriate, reflect recent modifications to the system and

2. located in the control room and other applicable plant areas and are controlled, current, and approved for use.

b. Component operating positions as noted during a walkdown of the system are consistent with the "as left" positions documented in the most recently performed system lineup.

c. Operators are knowledgeable in the implementation of system operating and emergency procedures, especially with respect to recent modifications that changed the operating characteristics of the system.

d. General condition of equipment (e.g., no excess corrosion, no evidence of steam, water, oil leaks, no other significant deficiencies) is adequate to assure its operability.

e. A BOP system corrosion detection and control program is being implemented when used by the licensee.

02.04 Management Support. Review various licensee programs and management responses to various inspection reports and industry initiatives to ensure that:

a. Management is responsive to self-identified BOP problems, those identified by NRC inspectors, and those identified in IE Notices, inspection reports, SALP reports, etc.

b. Management is successful in reducing the number and frequency of plant trips initiated or complicated by BOP problems.

c. The licensee is participating in industry initiatives (NUMARC, EPRI, owners groups, etc.) that address BOP problems and solutions.

d. Adequate resources are allocated for identifying and solving BOP component or system problems.

02.05 Root Cause. Review plant operating and maintenance history for the past 2-years and interview key plant personnel to determine BOP system components that have a history of unreliability or that have caused or complicated recovery from plant trips and transients. If possible, select at least four components or events for further analysis and:

a. Determine the root cause for each component failure or event selected above by reviewing the licensee's root cause analysis, if performed. The root cause analysis should implicate broad programmatic areas such as maintenance, operator training, etc. that are contributors to the component failure or event, and that are in need of upgrade.

b. Assess the adequacy and timeliness of the corrective action taken by the licensee relative to preventing recurrence of the events or component failures selected in section 02.01a for review.

71500-03 INSPECTION GUIDANCE

The balance of plant inspection procedure is written for a detailed in-depth team inspection approach examining licensee's programs such as maintenance, modifications and design, operations, and corrective actions. The inspection should be prefaced with a "bagman" trip during which the team leader gathers inspection material for review and as part of a preparation effort prior to actually beginning the inspection. Although this IP is written for a team inspection approach, portions of the IP can be selected to focus on particular BOP issues that may affect a particular plant. Such reduced-scope inspections can be accomplished by a smaller team, or an individual inspector as appropriate.

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Although this IP does not have a specific regulatory basis, it does have a safety orientation because of the challenges BOP systems can have on safety-related systems and the safe operations of the plant. Therefore consistent with the objective of the operating reactor inspection program, the purpose of this inspection is to focus on safety. The intent of this IP is to justify to the licensee concerns about design, modification, maintenance, operations, and testing practices for BOP systems and components. If the inspection team considers that a particular plant is experiencing BOP system problems that are contributing to plant trips or complicating plant recovery, the inspection team should research licensee system documentation and interview key plant personnel to determine specific system components that display a history of unreliability or have caused plant trips and transients.

03.01 Inspection Requirement 02.01.a. The licensee should have a program which will identify repeated component or equipment problems so that appropriate reviews will be performed to investigate the root cause of repeated maintenance. The resolution to these maintenance problems could involve design changes, increased preventive maintenance on the equipment, or improved maintenance procedures. The overall intent of such programs is to be able to identify equipment or component problems that are causing the system to be less reliable so that appropriate corrective actions can be taken as soon as possible.

03.02 Inspection Requirement 02.01.b1. Typically, not all vendor recommended preventive maintenance items will be incorporated into the licensee's program nor it that necessary in order to have a good preventive maintenance program. However, the licensee should be able to justify why recommended vendor maintenance items were not incorporated into the program for those items which have a high failure rate.

03.03 Inspection Requirement 02.01.c. Procedures should be written by personnel familiar with the equipment or system. In any event, the inspector should ensure that the maintenance performed is adequate by reviewing vendor recommended procedures or other technical documents.

03.04 Inspection Requirement 02.01.e. Post-maintenance testing should ensure that not only does the component or equipment operate as originally designed but that its interaction within the system is satisfactory. For example, if a feedwater regulating valve was replaced, then the licensee must ensure that, not only does it operate satisfactorily mechanically, but also that its control features, as required by the feedwater control system, are satisfactory.

03.05 Inspection Requirement 02.02. The number of BOP system modifications selected should be large enough such that the inspector is able to select a modification which involves system hardware change or system hardware reconfiguration. If appropriate, the inspector should also review the adequacy of the 50.59 review performed by the licensee.

03.06 Inspection Requirement 02.02.a. Codes and standards to which licensees are committed for the design, construction, and testing of the BOP systems are stated in appropriate sections of the FSAR and system design documents. In Code states, licensees must meet the ASME Code rules for design, construction, and testing of BOP systems. The utility also may elect

to adopt or utilize appropriate portions of other non-nuclear codes and standards; the extent to which this is the case should be determined.

03.07 Inspection Requirement 02.02.f. This area should be reviewed by an inspector with design experience. The review may necessitate that the inspector be at a location other than the site in order to review the design documents for the original design requirements. The level of review should be detailed if preliminary calculations cause the inspector to doubt the validity of the licensee's calculations based on his knowledge of the system or his own experience. If the licensee's calculations are in doubt, the inspector should reevaluate the calculations and determine the safety significance of the calculation error to the system and the plant.

03.08 Inspection Requirement 02.02g. Modifications made to the BOP system or components, or to related support systems, could possibly decrease reliability and increase the frequency of unplanned trips. If the modifications reviewed are implicated as contributing to or causing problems that resulted in challenges to safety systems, the impact should have been considered by the licensee in the 10 CFR 50.59 safety evaluation.

03.09 Inspection Requirement 02.03b. Walkdowns should not only verify that the actual system configuration is consistent with the latest valve line-up, but also that the actual system configuration will function as designed with all the system modifications in effect. To this end, the inspection team needs to verify that the system configurations are consistent with the latest system designs.

03.10 Inspection Requirement 02.04a. Developing issues with respect to BOP and presenting these to the licensee requires a different approach than for safety-related systems because of a shortage of prescriptive requirements. The basis for addressing BOP issues with licensees is that an aggressive, safety-conscious management approach will not be limited solely to safety-related hardware but will be reasonably applied to BOP systems that may cause challenges to safety systems at a relatively high frequency. When the licensee's programs do not conform to reasonable practices the inspection team should inform the licensee that implementation of these practices has the potential for increasing BOP system or component reliability and decreasing safety system challenges.

03.11 Inspection Requirement 02.05b. Responsiveness to the team's findings, the adequacy of the planned corrective actions indicate the licensee's commitment to safety in a non-safety system. The inspection team should review the licensee's plans for addressing identified BOP problems in terms of analyzing, defining, planning, scheduling, implementing, tracking, and reporting problems and their solutions. The licensee should have considered the generic applicability of the problem in determining corrective actions.

END