U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket/Report Nos.:	50-220/98-02 50-410/98-02
License Nos.:	DPR-63 NPF-69
Licensee:	Niagara Mohawk Power Corporation P. O. Box 63 Lycoming, NY 13093
Facility:	Nine Mile Point, Units 1 and 2
Location:	Scriba, New York
Dates:	February 15 - April 11, 1998
Inspectors:	B. S. Norris, Senior Resident Inspector T. A. Beltz, Resident Inspector R. C. Ragland, Radiation Specialist R. A. Skokowski, Resident Inspector
Approved by:	Lawrence T. Doerflein, Chief Projects Branch 1 Division of Reactor Projects

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ATTACHMENTS

EXECUTIVE SUMMARY

Nine Mile Point Units 1 and 2
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This NRC inspection report includes reviews of licensee activities in the functional areas of operations, engineering, maintenance, and plant support. The report covers a eight-week period of inspections and reviews by the resident staff and a regional specialist in the area of radiation protection.

PLANT OPERATIONS

The Unit 2 operators responded appropriately to the March 28, 1998, partial loss of offsite power.

The Unit 2 residual heat removal system walkdown and performance history reviews indicated that the material condition of the system was good, and that the system demonstrated a high level of reliability. However, two minor discrepancies were identified which differed from the design contained in the UFSAR and were not cited due to their minor safety consequence.

The NRC noted several degraded conditions in the Unit 1 control room which were not formally identified as Control Room Deficiencies. However, the operators and system engineers were aware of the problems and actions were in-place to address them. This minor procedural non-compliance was not cited.

A non-conservative operating philosophy resulted in exceeding the Unit 1 maximum allowable core thermal power during the eight-hour shift-average. The computer program which calculated and reported the shift-average power did not provide a sufficiently accurate readout of reactor power to assist the control room staff. NMPC's investigation identified seven other instances since the beginning of the year where the TS limit of 1850 MW_{th} was exceeded. This licensee identified and corrected TS violation was not cited.

LER 50-410/98-02 appropriately documented the circumstances involving a Unit 2 reactor operator who left the "at-the-controls" area of the control room. The NRC staff's disposition of this apparent TS violation remains under review. **(EEI 50-410/98-02-04).**

MAINTENANCE/SURVEILLANCE

During troubleshooting of the Unit 1 control room ventilation system temperature control valve, an unanticipated repositioning of the control room ventilation system dampers occurred. This resulted in the control room emergency ventilation system being declared inoperable. The inspectors determined that the planning for the troubleshooting should have identified the impact on the dampers. The failure to have identified this plant impact during the work order preparation was a violation of TS 6.8.1. **(VIO 50-220/98-02-05)**

The recent lubrication procedure improvements at both units were good. Program enhancements at Unit 2 have been effective in eliminating component unavailability related to the lubrication program. The inspectors considered that past operator training and lubrication procedures at both units were weak and that some individuals exercised poor judgement when adding grease. Overall, the lubrication programs at both units were acceptable.

ENGINEERING

During their Generic Letter 96-01 review of safety-system logic testing, NMPC identified that portions of the loss of power/degraded voltage circuitry at Unit 2 were not being tested as required by TSs. Prompt and appropriate corrective actions were taken to demonstrate logic system operability. This licensee identified and corrected surveillance testing deficiency was not cited.

NMPC's failure to properly maintain the control room emergency ventilation system design attributes and to properly test the system to demonstrate operability in accordance with the UFSAR is a violation of 10 CFR 50, Appendix B, Criteria III and XI. (VIO 50-220/98-02-08, -09, and -10). The immediate actions taken by the NMPC staff to initiate a detailed design review, implement interim compensatory measures, and to report this problem in accordance with 10 CFR 50.72 and 50.73 were determined to have been appropriate.

The engineering calculations, supporting analyses, temporary modifications, and safety evaluations associated with the operability determination for the degraded condition of the Unit 1 control room emergency ventilation system (CREVS) were generally well prepared. The inspectors identified that 1991 calculations projected, under worst case conditions, that the CREVS may not have been able to maintain the control room temperature below the UFSAR value of 75°F. This minor 10 CFR 50, Appendix B, Criterion XVI violation was not cited.

At Unit 2, probabilistic risk arguments were incorrectly used to justify less restrictive pipe stress limits in seismic qualification analyses for temporary shielding. Based on the analyses, the temporary shielding installed during refueling outages in 1992, 1993, 1995, and 1996, resulted in four systems exceeding allowable pipe stresses. This licensee identified and corrected violation was not cited.

Prior to October 1993, NMPC failed to perform TS logic system functional testing of the reactor vessel high water level main turbine trip at Unit 2 in accordance with an established surveillance test procedure. Fortuitously since October 1993, NMPC has tested this trip function per a repetitive work order. This licensee identified and corrected violation was not cited.

PLANT SUPPORT

Radioactive calibration and check sources were well controlled in that procedural guidance for the control and issuance of radioactive sources was clear, storage cabinets for

radioactive sources were securely locked, sources were stored in a neat and orderly fashion, and source issuance records for 1998 were complete.

Radiological controls for the Unit 1 1998 Fuel Pool clean out project were thorough and sound, and included lessons learned from industry events and close health physics oversight.

REPORT DETAILS

Nine Mile Point Units 1 and 2
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February 15 - April 11, 1998

SUMMARY OF ACTIVITIES

Niagara Mohawk Power Corporation (NMPC) Activities

Unit 1

Nine Mile Point Unit 1 (Unit 1) maintained essentially full (100%) power throughout the inspection period, with minor decreases in power for various maintenance activities. On February 20, 1998, NMPC declared the control room emergency ventilation system (CREVS) inoperable due to uncertainties in the configuration and operation of the system (see Section E7.1 of this inspection report (IR)); the system was returned to service on February 27.

Unit 2

Nine Mile Point Unit 2 (Unit 2) started the inspection period at 95% power, limited to 95% due to the moisture separator reheaters being removed from service. On February 17, 1998, the "B" condensate pump was removed from service due to a bearing failure, Unit 2 was maintained at about 88% until March 2, when power was increased to 92%. NMPC determined that 92% was the maximum achievable power without the "B" condensate pump. NMPC plans to repair the pump during the upcoming refueling outage, scheduled to start May 2, 1998.

Management Reorganization

On February 27, 1998, NMPC announced management changes related to Nine Mile Point, which took effect on March 9:

- John T. Conway, previously the Vice President - Nuclear Engineering, became the Vice President - Nuclear Generation. This position is responsible for the overall operation and maintenance of both units.
- Richard B. Abbott, previously the Unit 1 Plant Manager, replaced Mr. Conway as the Vice President - Nuclear Engineering.
- Robert G. Smith, previously the Unit 1 Operations Manager, replaced Mr. Abbott as the Unit 1 Plant Manager.

In addition, the following changes became effective on April 1:

- James G. Burton, previously Manager - Quality Assurance, became the Manager - Nuclear Training.

- Norman L. Rademacher, previously responsible for oversight of the corrective action program, replaced Mr. Burton as the Manager - Quality Assurance.

Nuclear Regulatory Commission (NRC) Staff Activities

Inspection Activities

The NRC resident inspectors conducted inspection activities during normal, backshift, and deep backshift hours. In addition, a specialist from Region I conducted an inspection in the area of radiation protection. The results of the inspection activities are contained in the applicable sections of this report.

Updated Final Safety Analysis Report Reviews

While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the Updated Final Safety Analysis Report (UFSAR) related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters. Exceptions noted were:

- two minor discrepancies identified with the Unit 2 low pressure coolant injection system (see Section O2.1);
- the Unit 1 control room emergency ventilation system was not being maintained and tested per the UFSAR, resulting in the system being declared inoperable and corrective actions implemented (see Sections E7.1 and E7.2); and,
- the identification that temporary shielding used during the last 4 Unit 2 refueling outages was not analyzed for seismic considerations (see Section E8.10).

I. OPERATIONS

O1 Conduct of Operations (71707)[1]

O1.1 General Comments

Using NRC Inspection Procedure 71707, the resident inspectors conducted frequent reviews of ongoing plant operations to verify that the units were operated safely and in accordance with licensee procedures and regulatory requirements. The reviews included tours of both accessible and normally inaccessible areas of both units, verification of engineered safeguards features (ESF) system operability, verification of adequate control room and shift staffing, verification that the units were operated in conformance with technical specifications, and verification that logs and records accurately identified equipment status or deficiencies. In general,

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[1] Topical headings such as O1, M8, etc., are used in accordance with the NRC standardized reactor inspection report outline. Individual reports are not expected to address all outline topics. The NRC inspection manual procedure or temporary instruction (TI) that was used as inspection guidance is listed for each applicable report section.

the conduct of operations was professional and safety-conscious; specific events and noteworthy observations are detailed in the sections below.

O1.2 Unit 2 - Partial Loss of Offsite Power

a. Inspection Scope

The inspectors assessed the licensee's actions taken in response a Unit 2 partial loss of offsite power. The assessment included a review of the Station Shift Supervisor's (SSS's) logs, discussions with the licensed operators on duty during the event, a review of equipment response to the event, the licensee's actions to address unexpected equipment response, and discussions with system engineers. Also, the inspectors discussed event cause and offsite breaker maintenance history with the operations staff, including the individual responsible for the root cause analysis. During the assessment, the inspectors reviewed applicable Deviation/Event Reports (DERs), the Technical Specifications (TSs), and the applicable UFSAR sections.

b. Observations and Findings

On March 28, 1998, Unit 2 experienced a partial loss of offsite power due to Line 5 becoming deenergized. Line 5 is one of two offsite 115 kilovolt electrical sources that feed the Unit 2 safety-related emergency switchgear through a step-down transformer. At the time of the event, Line 5 was feeding both the Division I and Division III emergency switchgear. Upon the loss of Line 5, Division I and III emergency diesel generators (EDGs) started and powered the respective emergency switchgear, as designed. Based on the SSS's logs and discussions with the operators, the inspectors concluded that the on-shift crew responded appropriately to the event and took the actions required by the procedures, TS, and 10 CFR 50.72. Subsequently, NMPC identified and isolated a fault on the offsite electrical distribution grid. Approximately two hours after the loss of Line 5, it was returned to service and the normal electrical distribution lineup was restored.

During the transient, a few components did not respond as expected. The operators restarted the equipment, as needed, and initiated DERs for further evaluation. Most significantly, the Division I control room special filter train (CRSFT) failed to operate, as expected. Specifically, the deenergization of the control building ventilation radiation monitor initiated the CRSFT start process; the bypass damper went shut, but the CRSFT booster fan did not start. With the bypass damper closed and the booster fan not running, ventilation to the control room envelope was isolated. DER 2-98-0722 was written to address this concern.

During NMPC's investigation of the CRSFT response to the transient, the system engineers determined that although the system did not response as expected, it did respond as designed. This was based on the system engineers' evaluation of the sequence of events impacting the CRSFT starting process during the transient, including the various time delays, and permissive and response time of the sensors in the starting circuitry. The system engineers were able to confirm the sequence

of events by testing the CRSFT start circuitry. The function of the CRSFT, as described in the UFSAR, is to automatically divert the control building ventilation intake through the special filter train during high supply-air radiation level conditions or in the event of a loss of coolant accident (LOCA). The system engineers were able to verify through their testing that the CRSFT design was adequate to perform the design function.

As part of NMPC's actions to disposition the DER, they plan (1) to evaluate the CRSFT starting circuitry design for improvements, and (2) to revise the applicable procedures to alert operators to the CRSFT response during a loss of offsite power. The inspectors reviewed the DER, applicable plant drawings, portions of the UFSAR and TS, and discussed the issue with the system engineers, operators, and training staff, and found the licensee's evaluation and planned actions to be acceptable. However, since the CRSFT performed as designed, the inspectors questioned the fidelity of the simulator; specifically, the operators expected the system to start on a loss of offsite power. Subsequently, NMPC determined that the simulator was incorrect, and a change was completed to correct the logic for the simulator circuitry.

Approximately two hours after the loss of Line 5, the offsite power control center informed the Unit 2 control room that the loss was due to the failure of a 345 kilovolt circuit breaker which feeds Line 5. The breaker experienced a loss of sulfur hexa-fluoride (SF_6) gas, and subsequently developed a fault. This type of circuit breaker uses SF_6 gas to quench arcs that are developed during operation (i.e., opening or closing) of the breaker; the SF_6 gas also provides insulation. Upon loss of the SF_6 gas pressure, the circuit breaker will not open; instead, the breakers downstream of it are designed to open to isolate a fault. Therefore, when the fault occurred, the circuit breakers supplying Line 5 opened as part of the protection scheme to isolate the fault.

During discussions with the NMPC staff member leading the root cause investigation, the inspectors learned that the circuit breaker that failed was an ABB 362 kilovolt circuit breaker, type 362PM 50-30. The breaker had been installed approximately four years ago. Routine preventive maintenance had been completed on the breaker in accordance with the vendor's recommendations, by a non-nuclear division of NMPC. During the licensee's root cause investigation, they determined that one of the SF_6 rupture disks was improperly installed during original assembly, which allowed the disk to degrade. Based on information from the vendor, NMPC informed the inspectors that this was not a generic problem, and it should have no effect on the other five similar circuit breakers within the NMPC system. However, NMPC was investigating means to verify proper installation of the rupture disks on the other circuit breakers.

NMPC learned that the offsite power control center was aware of the loss of SF_6 gas on the breaker for approximately two hours before the breaker failed; but no attempts were made to inform the Unit 2 control room. The power control center had requirements to contact the control room during specific conditions, but the conditions were all associated with the 115 kilovolt distribution system. Since the

loss of SF_6 gas to these type breakers could adversely impact the offsite power to the Nine Mile Station, NMPC was evaluating possible enhancements to the power control center's procedures to allow for possible forewarning of the control rooms.

c. Conclusions

The Unit 2 operators responded appropriately to the March 28, 1998, partial loss of offsite power.

O2 Operational Status of Facilities and Equipment (71707)

O2.1 Unit 2 Low Pressure Coolant Injection System Engineered Safety Feature Walkdown

a. Inspection Scope

The inspectors assessed the ability of the low pressure coolant injection (LPCI) mode of the residual heat removal (RHR) system to perform the intended function. This assessment included a visual inspection (walkdown) of accessible portions of the subsystem "C" LPCI. The inspectors observed performance of two surveillance tests and reviewed other completed surveillance tests associated with the LPCI mode of RHR. The inspectors reviewed the RHR "System Health" report, the UFSAR, TSs, inservice inspection and inservice testing programs, and applicable operating procedures. The inspectors also reviewed the RHR system with respect to the Maintenance Rule (10 CFR 50.65). During the assessment, the inspectors discussed the related issues with the system engineer, operators, and the Operations and Technical Support Managers.

b. Observations and Findings

System Description: LPCI is an emergency operating mode of the RHR system. In the event of a LOCA, the LPCI pumps, in conjunction with other emergency systems, are designed to restore and maintain the desired water level in the reactor vessel. Maintaining the proper water level provides adequate cooling capability to prevent fuel overheating. In the LPCI mode, the three RHR pumps take suction from the suppression pool and discharge into the reactor vessel via three separate lines. To prevent over-pressurizing the RHR system piping, the LPCI injection valve will not open until reactor vessel pressure is within 130 pounds per square inch differential (psid) of LPCI injection pressure. The LPCI mode of RHR will automatically initiate on high drywell pressure and/or low reactor vessel water level, or can be manually initiated from the control room.

The inspectors performed a walkdown of accessible portions of the "C" LPCI Loop to compare plant drawings and Procedure N2-VLU-01, "Walkdown Order Valve Lineup & Valve Operations," Attachment 31: N2-OP-31 Walkdown Valve Lineup, with actual valve positions. One minor discrepancy was noted. The valve lineup stated that the inboard vent between the "C" LPCI injection valve and the testable check valve should be closed and capped. However, UFSAR, Figure 5.4.13a does not show the valve as capped. Since this valve is inside the drywell, the inspectors

were unable to verify actual system lineup. The last valve lineup completed by the licensee in October 1996 indicated that the valve was closed and capped. Based on the inspectors' finding, the system engineer initiated a DER to review the discrepancy.

The inspectors also noted that the actual LPCI pump discharge relief valve setpoint of 470 pounds per square inch gauge (psig) differed from the 500 psig stated in UFSAR, Section 6.3.2.2.4. The purpose of the relief valve is to protect the RHR components and piping from inadvertent over-pressure conditions. Discussion with the system engineer indicated that the lower setpoint provided more conservative over-pressure protection without adversely impacting the operation of the system. In addition, NMPC had identified this discrepancy during their UFSAR review.

The failure to maintain the actual plant design in accordance with the design described in the UFSAR regarding the vent line cap and the relief valve setpoint is a violation of 10CFR50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," Criterion III, "Design Control." This failure constitutes a violation of minor significance and is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy.
(NCV 50-410/98-02-01)

In general, the material condition of the equipment appeared to be good. The inspectors identified no valve leakage. Housekeeping and equipment labeling were generally good.

The inspectors reviewed completed surveillance tests associated with the RHR system. The inspectors determined that the tests included the surveillance and testing requirements contained in the TS and UFSAR. The inspectors observed RHR system surveillance tests, N2-OSP-RHS-Q@001, "Residual Heat Removal System Loop A Valve Operability Test and Partial ASME [American Society of Mechanical Engineers] XI Pressure Test," and N2-OSP-RHS-Q@004, "RHR System Loop A Pump & Valve Operability Test and System Integrity Test and ASME XI Pressure Test." The surveillance tests were completed satisfactorily with no concerns identified by the inspectors.

The inspectors reviewed the current RHR "System Health" report and discussed system performance with the system engineer. There was no indication of major corrective maintenance associated with the system. Additionally, the inspectors verified that the RHR system was performing within the Maintenance Rule established acceptance criteria.

c. <u>Conclusions</u>

The Unit 2 residual heat removal system walkdown and performance history reviews indicated that the material condition of the system was good, and that the system demonstrated a high level of reliability. However, two minor discrepancies were identified which differed from the design contained in the UFSAR and were treated as non-cited violations due to their minor safety consequence.

O2.2 Unit 1 Degraded Equipment not Appropriately Identified as Control Room Deficiencies

a. Inspection Scope

The inspectors observed that several Unit 1 control room indicators were degraded, but were not formally identified as control room deficiencies. These deficiencies were discussed with the on-shift supervision, the Unit 1 General Supervisor of Operations (GSO) and the appropriate branch manager. In addition, the inspectors reviewed the licensee's governing procedure for control room deficiencies.

b. Observations and Findings

During various tours of the Unit 1 control room, the inspectors noted that several indicators used by the control room operators were either inoperable or degraded. Specifically, (1) both chart recorders for drywell floor drain (DWFD) leakrate periodically spiked upscale; (2) two of the four radiation monitors for the containment spray raw water (CSRW) system were out of calibration; and (3) the alarm for control room-to-turbine building differential pressure was not properly calibrated (see Section E7.1).

The operators were aware of the problem with the DWFD recorders, and informed the inspectors that the spikes were infrequent, and that the recorders usually returned to a normal indication within a few minutes. This condition had been previously identified, as documented by DER 1-97-1996. The operators also informed the inspector that two CSRW radiation monitors were out-of-calibration and explained that all four of the monitors were scheduled to be "retired-in-place." Operator recognition of the radiation monitors being out-of-calibration per discussions with the inspectors prompted them to issue DER 1-98-0644. During the review of the CREVS issue (see Section E7.1), the system engineer identified that the alarm for low control room-to-turbine building differential pressure (annunciator window L1-4-1) was not functioning properly, and DER 1-98-0169 was issued.

Although the operators and system engineers were aware of the specific hardware problems, the inspectors identified that none of the equipment deficiencies had been properly identified as a "control room deficiency," in accordance with Unit 1 Operating Department Guideline, N1-ODG-06, "Control Room Deficiencies Guideline," Revision 6. The failure to implement the control room deficiency program, as described in N1-ODG-06, constitutes a violation of minor significance and is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy. **(NCV 50-220/98-02-02)**

c. Conclusion

The NRC noted several degraded conditions in the Unit 1 control room which were not formally identified as Control Room Deficiencies. However, the operators and system engineers were aware of the problems and actions were in-place to address them. This minor procedural non-compliance was treated as a non-cited violation.

O5 Operator Training and Qualification (71001, 71707)

O5.1 Observation of Unit 2 Simulator Training

The inspectors observed a licensee critiqued simulator training scenario for Unit 2 licensed operators. The inspectors identified no significant concerns regarding the scenario quality, the operating crew's performance, or the instructors' critique of the crew performance. However, the inspectors addressed the following minor observations with the licensee:

- Due to considerable interaction between the Station Shift Supervisor (SSS) and Assistant Station Shift Supervisor (ASSS) during the implementation of the emergency operating procedures (EOPs), the inspectors were unable to assess the ability of the ASSS to carry out the EOPs.

- Some long-term equipment problems that exist in the plant, such as the longstanding holdout on the 'B' condensate pump, were not reflected into the scenario initial conditions.

- The switch position for several smoke removal dampers in the simulator did not reflect that of the control room.

O8 Miscellaneous Operations Issues (90712, 92700, 92901)

O8.1 (Closed) URI 50-410/96-01-01: Contradiction Between Control Room Blackboard Philosophy and Rosemont Trip Units

In late-1995, the Nine Mile site adopted a philosophy of "blackboard" operations; i.e., normal operating conditions are indicated by having no control room annunciators illuminated (alarming). During a 1996 tour of the Unit 2 control room, the inspectors identified several back-panel Rosemont trip units (RTUs) in the alarming condition. At that time, the inspectors discussed the issue with the Operations Manager.

NMPC concurred that the alarming RTUs were not consistent with the blackboard philosophy. NMPC determined that modifications to the affected RTUs were not appropriate; however, a list of all normally alarming RTUs was generated and included in the Unit 2 Night Order Book. The inspectors reviewed the list, and independently verified that the list was accurate. In addition, the inspectors interviewed several control room operators, and determined that the shift personnel

were cognizant of which RTUs should be in alarm. There was no procedural requirement connected with the blackboard philosophy. This item is closed.

O8.2 (Closed) URI 50-220 & 50-410/96-07-08: Post-Job Critique Information Not Entered Into Work Control Database

During the NRC Integrated Performance Assessment Process (IPAP) inspection in March 1996, the IPAP inspection team reviewed maintenance controls, including post-job critiques. The IPAP team identified that only about 25% of the critique form information was incorporated into the work control (WC MOSSE - work control, maintenance, operations, stores, spares, and engineering) database. The NRC was concerned that work history and lessons learned were not captured into the WC MOSSE database for future work packages. The concern was categorized as an unresolved item pending additional NRC review of the NMPC procedural requirements associated with the post-job evaluation.

As a result of the NRC's concern, NMPC initiated DER C-96-3239. NMPC noted that the procedure which defined the process for the generation of work packages (GAP-PSH-01, "Work Control") did not define the responsibility or requirement for incorporation of post-job critique information. At that time, Procedure GAP-PSH-01 was revised to clearly define the first line supervisor as responsible to ensure that useful information and important history were entered into WC MOSSE. The current revision of the procedure (Revision 18), paragraphs 3.21.3 and 3.21.4, states that planning personnel shall review field completed work order (WO) records for feedback from the field crews and shall preserve information that will improve the quality of future work packages. In addition, training was conducted for planning and maintenance personnel on the changes to GAP-PSH-01.

The inspectors reviewed the completed DER and the training package, and discussed the improvements to GAP-PSH-01 with maintenance planners from both units. The changes appear appropriate. Also, the inspectors routinely review in-process work packages during every inspection period and have noted that most packages do contain "lessons learned." The inspectors noted there was no requirement regarding this issue and they had no further questions. This item is closed.

O8.3 (Closed) LER 50-220/98-03: Power/Flow Relationship Technical Specification Violation (Operation Above Rated Power) Due to Inadequate Managerial Methods

a. Inspection Scope

During a review of the Unit 1 process computer printout, NMPC identified that the shift-average reactor thermal power exceeded the operating license maximum. The inspectors discussed the event with NMPC management, and reviewed the associated DERs and the Licensee Event Report (LER).

b. Observations and Findings

NMPC identified that, on March 4, 1998, Unit 1 exceeded the maximum rated core thermal power allowed by the Operating License and TSs. Specifically, the 4:00 p.m. computer printout for the shift-average power (the last eight hours) indicated 1851 megawatts thermal (MW_{th}); the maximum allowed power is 1850 MW_{th} which equates to 100% full power.

Instantaneous thermal power is continuously displayed in the control room on a large digital readout and the plant process computer records this value every ten minutes (computer point C875). These ten-minute values are then averaged by the process computer to provide the shift-average core thermal power (C873). Both computer points are printed on a control room typer. The shift-average value is printed hourly and is rounded to the nearest whole number. Computer point C873 is then reset every eight hours (i.e., the inputs to C873 reset at midnight, 8:00 a.m., and 4:00 p.m.).

At Unit 1, reactor power oscillates about ± 6 MW_{th} due to flow-related design characteristics. The control room operators historically have maintained the digital display at approximately 1850 MW_{th}, and monitored C873 to ensure that the shift-average did not exceed the rated core thermal power limit of 1850 MW_{th}. On March 4, the hourly printouts for C873 between 8:00 a.m. and 3:00 p.m. were all 1850 MW_{th}, but the printout at 4:00 p.m. was 1851 MW_{th} ($\approx$100.06%). The SSS documented this condition on DER 1-98-0507. As part of the DER follow-up, NMPC identified that since the beginning of the year there were seven other occasions when the TS limit of 1850 MW_{th} was exceeded (each event was recorded as less that 1850.5 MW_{th}, while C873 indicated 1850 MW_{th}).

NMPC concluded that the root cause for this issue was inadequate managerial methods, in that, a non-conservative operating philosophy resulted in expectations that operators would maintain the shift-average power level as close as possible to 1850 MW_{th}. Immediate corrective actions included reducing thermal power and administratively limiting power to 99.5% (1840 MW_{th}). At the conclusion of the inspection period, the licensee was reviewing the feasibility of a new computer program for calculating C873. In addition, training on the lessons learned of this event and the new administrative power limit was conducted with the entire operations staff.

The failure to maintain the shift-average for reactor core thermal power less than 1850 MW_{th} is contrary to the Unit 1 TS, Section 3.1.7.d, which requires the reactor power and recirculation flow relationship be maintained in accordance with the limits identified in the Core Operating Limits Report (COLR). The COLR identifies the upper limit for rated core thermal power as 100%. However, this non-repetitive, licensee identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. (NCV 50-220/98-02-03)

The inspectors verified that the LER was completed in accordance with the requirements of 10CFR50.73. Specifically, the description and analysis of the event, as contained in the LER, were consistent with the inspectors' understanding of the event. The root cause and corrective actions as described in the LER were reasonable. This LER is closed.

c. Conclusion

A non-conservative operating philosophy resulted in exceeding the Unit 1 maximum allowable core thermal power during the eight-hour shift-average. The computer program which calculated and reported the shift-average power did not provide a sufficiently accurate readout of reactor power to assist the control room staff. NMPC's investigation identified seven other instances since the beginning of the year where the TS limit of 1850 MW_{th} was exceeded. This licensee identified and corrected TS violation was not cited.

O8.4 (Closed) LER 50-410/98-02: Violation of TS 6.2.2.b - Licensed Operator Not At-The-Controls

a. Inspection Scope

During an NMPC internal investigation into a personnel related issue, the licensee identified that there was no licensed operator "at-the-controls" of Unit 2, as required by the TSs. The inspectors discussed the event with the Unit 2 Plant Manager, reviewed the TS, UFSAR and associated procedures, and performed a limited independent review of the issue.

b. Observations and Findings

On December 25, 1997, NMPC identified that Operations Department personnel files were missing from the Unit 2 SSS office. During the subsequent internal investigation, NMPC determined that a licensed reactor operator (RO) had removed the files. Unit 2 TS, Section 6.2.2.b, requires at least one RO or senior reactor operator (SRO) to be "at-the-controls" of the unit during power operation. The "at-the-controls" area is defined in the Unit 2 UFSAR, Figure 13.5-1; the SSS office is not part of the "at-the-controls" area. A review of the security logs for the electronic card readers for the Unit 2 control room revealed that the RO could have been away from the "at-the-controls" area for as much as six minutes. There was no other RO or SRO in the "at-the-controls" area during this time. This event and the NRC's disposition of this apparent violation of Technical Specifications is subject to further NRC staff review. (EEI 50-410/98-02-04)

The inspectors verified that the LER was completed in accordance with the requirements of 10CFR50.73. The description and analysis of the event, as contained in the LER, were consistent with the inspectors' preliminary review and understanding of the event. The root cause and corrective actions, as described in the LER, appear to be reasonable. LER 50-410/98-02 is closed.

c. Conclusion

LER 50-410/98-02 appropriately documented the circumstances involving a Unit 2 reactor operator who left the "at-the-controls" area of the control room. The NRC staff's disposition of this apparent TS violation remains under review. (EEI 50-410/98-02-04).

II. MAINTENANCE [2]

M1 Conduct of Maintenance (60705, 61726, 62707)

M1.1 General Comments

Using NRC Inspection Procedures 61726 and 62707, the resident inspectors periodically observed plant maintenance activities and the performance of various surveillance tests. As part of the observations, the inspectors evaluated the activities with respect to the requirements of the Maintenance Rule, as detailed in 10CFR50.65. In general, maintenance and surveillance activities were conducted professionally, with the work orders (WOs) and necessary procedures in use at the work site, and with the appropriate focus on safety. Specific activities and noteworthy observations are detailed in the inspection report. The inspectors reviewed procedures and observed all or portions of the following maintenance/surveillance activities:

- N1-ISP-036-006 — Emergency Cooling System - High Steam Flow Instrument Trip Channel Test/Calibration
- N1-ST-C9 — Control Room Emergency Ventilation Operability Test
- N1-OP-49 — Control Room Ventilation System
- N1-ISP-0360006 — Emergency Cooling System - High Steam Flow Instrument Trip Channel Test/Calibration
- N2-OSP-ICS-Q@002 — RCIC [reactor core isolation cooling] Pump and Valve Operability Test and System Integrity Test and ASME XI Functional Test
- N2-MMP-FHP-099 — Receiving, Inspection, and Storage of New Fuel
- N2-OSP-RHS-Q@001 — Residual Heat Removal System Loop A Valve Operability Test and Partial ASME XI Pressure Test
- N2-OSP-RHS-Q@004 — RHR System Loop A Pump & Valve Operability Test and System Integrity Test and ASME XI Pressure Test
- N2-OSP-RHS-R001 — Division 2 ECCS [emergency core cooling system] Functional Test
- N2-EPM-GEN-V520 — Limitorque Actuator (Type SMB, SB and SMC) P.M.
- N2-ISP-CSH-Q005 — Quarterly Functional Test and Trip Unit Calibration of Condensate Storage Tank Level Low Instrumentation for HPCS [high pressure core spray] Suction Transfer

[2] Surveillance activities are included under "Maintenance." For example, a section involving surveillance observations might be included as a separate sub-topic under M1, "Conduct of Maintenance."

• N2-OSP-RHS-CS002	Residual Heat Removal System B/C Cold Shutdown Valve Operability Test
• N2-OSP-RHS-Q@002	Residual Heat Removal System Loop B Valve Operability and Partial ASME XI Pressure Test
• N2-OSP-RHS-Q003	Residual Heat Removal System Loop C Valve Operability Test
• N2-OSP-RHS-Q@006	RHR System Loop C Pump & Valve Operability Test and System Integrity Test
• N2-OSP-RHS-M001	RHR Discharge Piping Fill (LPCI) and Valve Lineup Verification
• N2-OSP-ENS-R@001T	Functional Test of Emergency Diesel Generator Load Sequencing Circuit
• RHO 2-98-H087	SWP*MOV90A, Repack Valve and Change out Gland Follower Bolts (Unit 2)
• RMU 2-98-00380	SWP*MOV90A, Repack Valve and Change out Gland Follower Bolts (Unit 2)
• WO 97-14531-05,6,7	New Fuel Receipt (Unit 2)
• WO 98-01042-00	Replace High Pressure Head Gasket on EDG-103 Air Compressor (Unit 1)
• WO 98-01319-03	Inspect Contacts on Channel 11 Emergency Cooling Isolation Relay (Unit 1)
• WO 98-01863-00	Repair Seal Weld on Bonnet to Body of Valve RHS*V69 (Unit 2)
• WO 98-00883-01	Support Troubleshooting of VLV-210.1-56, Check Operation of Controller TC-210-90 (Unit 1)
• WO 98-01319-03	Inspect Relay Contacts for the Channel 11 Emergency Cooling Isolation Relay (Unit 1)

M1.2 Unanticipated Repositioning of the Unit 1 Control Room Ventilation System Dampers during Troubleshooting

a. Inspection Scope

The inspectors reviewed the details associated with an unanticipated repositioning of the Unit 1 control room ventilation system dampers during troubleshooting of the control room temperature control valve (TCV). The inspectors reviewed the applicable WO, procedures, DER and plant drawings. The inspectors discussed the issue with the Unit 1 Work Control Manager and the Instrumentation and Controls (I&C) General Supervisor. Also, the inspectors reviewed the event with the respective I&C Supervisor; included in this review was a visual inspection of the jobsite and applicable equipment.

b. Observations and Findings

On March 11, 1998, I&C technicians were troubleshooting the Unit 1 control room TCV in accordance with WO 98-00883-01. The WO required the controller leads to be lifted so that the controller could be removed for bench testing, this caused an unanticipated repositioning of the control room dampers. This resulted in the SSS

declaring the control room emergency ventilation system inoperable. NMPC's investigation found that the neutral for the TCV and the control room damper control circuits were common at a connection on the TCV controller. When these leads were lifted, the damper control circuitry deenergized causing the dampers to reposition.

The plant impact for WO 98-0083-01 made no mention that lifting the TCV controller leads would affect the dampers. The inspectors assessed the adequacy of the WO plant impact statement by reviewing the applicable plant drawings and discussing the event with the I&C job supervisor, including a visual inspection of the jobsite and pertinent plant equipment. The inspectors concluded that the planning for the troubleshooting should have identified the effect on the control room ventilation system dampers. The failure to identify the plant impact during the preparation of WO 98-00883-01, as required by GAP-PSH-01 "Work Control," Revision 17, is a violation of Unit 1 Technical Specifications, Section 6.8.1. **(VIO 50-220/98-02-05)**

c. Conclusion

During troubleshooting of the Unit 1 control room ventilation system temperature control valve, an unanticipated repositioning of the control room ventilation system dampers occurred. This resulted in the control room emergency ventilation system being declared inoperable. The inspectors determined that the planning for the troubleshooting should have identified the impact on the dampers. The failure to have identified this plant impact during the work order preparation was a violation of TS 6.8.1. **(VIO 50-220/98-02-05)**

M1.3 Unit 2 New Fuel Receipt Activities

Throughout the inspection period, the inspectors observed Unit 2 new fuel receipt activities; such that, by the end of the inspection period, all portions of the new fuel receipt process were observed at least once. The inspectors noted that the activities were completed in accordance with the applicable procedures. Appropriate supervisory oversight and Quality Assurance (QA) observation were noted. Radiological protection surveys of the new fuel shipment and the oversight of the radiological work-practices were satisfactory.

M2 Maintenance and Material Condition of Facilities and Equipment (61726)

M2.1 Unit 2 RCIC Post-Maintenance Testing

The inspectors reviewed the post-maintenance testing (PMT) associated with the restoration of the Unit 2 reactor core isolation cooling (RCIC) system following adjustment to the RCIC pump controller. The PMT was performed several times and consisted of operating the RCIC system per surveillance procedure N2-OSP-ICS-Q@002, "RCIC Pump and Valve Operability Test and System Integrity Test and ASME XI Functional Test." Following completion of the PMT and NMPC review of the documentation, the RCIC system was returned to an operable

condition. The inspectors reviewed the surveillance procedure and determined that the PMT was completed appropriately, including the performance of support functions such as Chemistry Department staff sampling of the turbine lubricating oil. The inspectors had no questions or concerns regarding the testing.

M8 Miscellaneous Maintenance Issues (90712, 92700, 92902)

M8.1 (Closed) URI 50-220/96-07-05: Revised Post-Maintenance Testing Requirements Not Incorporated into an Existing Work Package

a. Inspection Scope

During the NRC IPAP inspection in March 1996, the IPAP inspection team reviewed DER 1-95-1945, which documented a licensee identified failure to incorporate revised PMT requirements into an existing work package. The IPAP inspection team categorized this concern as an unresolved item pending the NRC's review of the licensee's evaluation of the adequacy of the PMT performed on the Unit 1 reactor building track bay door containment seal, and the licensee's review of the work control process to ensure that the appropriate barriers were in place to prevent recurrence. The inspectors reviewed the associated DER and discussed the issue with operations department planning personnel.

b. Observations, Findings, and Conclusion

In March 1995, NMPC Procedure GAP-SAT-02, "Pre/Post-Maintenance Test Requirements," was revised to eliminate the use of a local leak rate test (LLRT) as a PMT for work on containment airlocks and penetrations. A training memorandum was issued to plant personnel to inform them of the revision; however, a delay in notifying the operations department planning personnel resulted in a failure to promptly update any applicable work packages. Licensee corrective actions for this oversight included assigning a training coordinator for the operations planning group. The training coordinator was to be responsible for ensuring that procedure revisions were promptly disseminated to the operations planning group, and the group would then consider the impact on current and proposed work.

The specific event which triggered DER 1-95-1945 was the result of an operator questioning the use of a LLRT as an adequate PMT for the track bay door containment seal, which affected secondary containment integrity. The questioning attitude subsequently identified the failure to incorporate the LLRT revision into the work package PMT. The inspector verified that the appropriate PMT was completed satisfactorily. Secondary containment integrity had not been violated, nor was secondary containment required at the time of the PMT. Consequently, there was no violation of regulatory requirements. This unresolved item is closed.

M8.2 <u>(Closed) URI 50-220 & 50-410/96-07-09: Lubrication Program Problems</u>

a. <u>Inspection Scope</u>

During the NRC IPAP inspection in March 1996, the NRC noted that lubrication program problems continued to occur at both units. The concerns were categorized as an unresolved item pending the NRC review of: (1) the adequacy of NMPC's lubrication programs, (2) the adequacy of corrective actions to address previously identified lubrication concerns, and (3) if the specific issues have been corrected. The inspectors reviewed the associated DERs and discussed the issues with plant personnel responsible for the lubrication programs at both units.

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

The IPAP inspection team noted that lubrication program problems continued to occur at both units. Particularly, the concerns were: (1) incorrect oil added to a Unit 1 control rod drive (CRD) pump bearing, (2) incorrect oil added to the Unit 1 shutdown cooling (SDC) pumps, and (3) several instances of delays in lubrication preventive maintenance at Unit 2 that resulted in increased equipment unavailability.

The inspectors reviewed the DERs and considered that the immediate corrective actions were adequate. At Unit 1, the licensee contacted the lubricant vendor and confirmed that the incorrect oils added to the CRD and SDC pumps were compatible, and that mixing them would not lead to phase separation or additive precipitation. Therefore, NMPC determined that the CRD and SDC pump operability was unaffected by the mixing of oils. In addition, oil samples were subsequently drawn and analyzed from twenty-eight other Unit 1 components; two additional motor bearings appeared to have mixed oils. Again, the licensee determined that component operability was unaffected, but the oil in the affected pumps was changed.

NMPC determined the failure to add the recommended oil to be a result of inadequate procedures and training. The inspectors considered operator inattention-to-detail to also be a contributor, in that, incorrect oil added to the SDC pumps was a different color from the original oil (visible through the sight glass). The lubrication program coordinators at both units informed the inspectors that procedure enhancements had been completed in response to these issues. The inspectors reviewed Unit 1 Procedure N1-PM-Q9, "Procedure for Operations Lubrication," and Unit 2 Procedure N2-PM-W001, "Lubrication of Equipment," and considered the procedures to be adequate.

In 1995, to address Unit 2 component unavailability, NMPC performed a DER database review and identified ten lubrication-related issues occurring between 1991 and 1995. In response, enhancements were made to Procedure N2-PM-W001, including: (1) delineating lubrication program responsibilities, (2) scheduling component lubrications using the preventive maintenance/surveillance testing data base, and (3) improving lubrication program implementation. Also, component lubrication was integrated into the 12-week rolling maintenance schedule and work

orders were utilized to facilitate the evolutions. A Unit 2 lubrication matrix was developed to identify plant equipment, lubricants and preventive maintenance frequencies, similar to the Unit 1 Lubrication Schedule. Overall, the inspectors observed that the implementation of lubrication preventive maintenance program enhancements at Unit 2 has been effective in eliminating component unavailability directly related to the lubrication program.

During discussions with the lubrication program coordinators, the inspectors noted that most of the problems were associated with over-greasing. The licensee attributed the following failures, in part, to component over-greasing: (1) a Unit 1 reactor building supply fan bearing (1996); (2) Unit 2 closed-loop cooling water pump motor bearings (1996); (3) Unit 2 low pressure core spray pump motor bearing seals (1996); (4) high vibration and excessive bearing wear on a Unit 2 reactor coolant pump motor generator set (1998); and (5) a Unit 2 condensate pump motor bearing (1998). The inspectors reviewed the associated DERs and discussed the issues with the lubrication program coordinators. When lubricating the Unit 1 reactor building supply fan bearings and the Unit 2 low pressure core spray pump motors, the amount of grease added was well in excess of that required. However, the bearings were greased in accordance with the then current lubrication procedures, which instructed personnel to add grease until grease exited the vents. The inspectors considered that these individuals exercised poor judgement, in that, they did not question the amount of grease added relative to the size of the component. Procedure N1-PM-Q9 was subsequently revised, consistent with industry standards, to limit the volume of grease added based upon shaft diameter, and revisions to Procedure N2-PM-W001 were in process.

Recently, DER 1-98-0297 was issued to address increased vibration on Unit 1 EDG 102 raw water pump. Subsequent licensee investigation identified that the lower motor bearings for EDG 102 and EDG 103 raw water pumps were not included in the operations lubrication schedule. The bearings on EDG 102 raw water pump were replaced, EDG 103 raw water pump motor bearings were subsequently greased, and the pump motor bearings were added to the lubrication schedule. The inspectors discussed the issue with the inservice testing (IST) supervisor and a mechanical maintenance supervisor. Both individuals stated that the bearings removed from EDG 102 would still have performed properly, even if the EDG was called upon for extended service. The inspectors observed the bearings which had been removed, and agreed with the licensee's conclusion. Additionally, IST informed the inspectors that an increased trend in vibration on EDG 102 raw water pump had been noted since 1995, and the vibration monitoring would have predicted any significant bearing degradation prior to failure. The inspectors considered the failure to include this safety-related component in the lubrication program to be a significant weakness which had the potential for a common cause failure of both EDG raw water pumps. The inspectors questioned whether any other safety-related components were excluded from the schedule. Upon disposition of the DER, the IST supervisor stated that a review of all components would be conducted to ensure that no other equipment was excluded from the lubrication schedule.

The inspectors reviewed NMPC's current lubrication program for both units and concluded that the past problems were adequately addressed and corrected. The lubrication programs for both units appeared adequately managed. Program improvements were continuing based on industry standards and in response to plant problems. Overall, the inspectors considered the lubrication program improvements at both units to be acceptable. No violations of regulatory requirements were noted. The inspectors had no further questions, and this URI is closed.

c. Conclusions

The recent lubrication procedure improvements at both units were good. Program enhancements at Unit 2 have been effective in eliminating component unavailability related to the lubrication program. The inspectors considered that past operator training and lubrication procedures at both units were weak and that some individuals exercised poor judgement when adding grease. Overall, the lubrication programs at both units were acceptable.

M8.3 (Closed) URI 50-410/96-07-10: Unit 2 Feedwater Pump Mechanical Seal Replaced Without a Procedure

a. Inspection Scope

During the NRC IPAP inspection in March 1996, the IPAP inspection team reviewed maintenance program and procedure controls. The review included an examination of completed work order packages for preventive and corrective maintenance. The team noted that one complex task, the mechanical seal replacement for the feedwater pumps at Unit 2, was completed without a procedure. The WO package provide did not contain instructions for how the work was to be performed, nor was there a reference to the vendor manual. The concern was categorized as an unresolved item pending NRC review of the NMPC procedural requirements. The inspectors reviewed the associated DER and procedures, the Unit 2 TSs, and applicable industry standards.

b. Observations and Findings

During the NRC IPAP inspection in March 1996, the IPAP inspection team identified that the mechanical seals were replaced on the Unit 2 feedwater pumps without a specific procedure; however, the work was done by a specially trained and qualified maintenance crew. The WO package provided general instructions for completion of the work, but did not contain detailed steps for how the task was to be performed.

NMPC initiated DER 2-96-0858 to resolve the NRC's concern. The root cause for not having a specific procedure was the failure to follow the governing procedure for generation of work instructions. At the time, GAP-PSH-01, "Work Control," Revision 13, Paragraph 3.7.1, would have classified this task as a Level I activity ("Task complexity requires that a task qualified individual needs a procedure to perform the activity"), which would have required an approved procedure. The

failure to have an approved procedure for a complex task constitutes a violation of minor significance and is being treated as a Non-Cited Violation consistent with Section IV of the NRC Enforcement Policy. (NCV 50-410/98-02-06)

The corrective actions included: (1) development of a procedure for replacement of the feedwater pump mechanical seals, and (2) a review of other system maintenance activities that should be considered for specific work procedures. The inspectors reviewed the DER, the new maintenance procedures, and discussed the issue with the Unit 2 work control planners. In addition, the inspectors reviewed the current revision of GAP-PSH-01 to ensure the above requirement is still present. The inspectors had no further questions. This item is closed.

c. Conclusion

During the NRC IPAP inspection in March 1996, the NRC identified that the Unit 2 feedwater pump mechanical seals were replaced without a specific maintenance procedure. The performance of this maintenance activity without detailed procedural guidance was contrary to station administrative procedures, but was of minor safety consequence and not cited.

M8.4 (Closed) LER 50-220/97-14-01: Vent and Purge System Isolation During Troubleshooting Due to Insufficient Precaution Applied

a. Inspection Scope

The inspectors reviewed the details associated with the LER Supplement, and discussed the revised root cause and corrective actions with the Unit 1 Maintenance and Technical Support Managers, and the Unit 2 I&C and Radiological Protection Calibration Supervisors.

b. Observations, Findings, and Conclusion

The inspectors reviewed the event associated with the original LER in NRC Inspection Report (IR) 50-220/97-12, Section M8.1. Originally NMPC determined the root cause to be equipment failure, specifically, an intermittent short circuit to ground in stack gas radiation monitor RAM-112-08A. The event occurred during troubleshooting, when a technician attached a test probe to the high voltage source and an arc occurred between the high voltage source and the low voltage power supply. The arc traveled through the previously undetected short circuit in the low voltage power supply to the station ground. The subsequent high voltage potential on the ground was detected in RAM-RN10A and 10B, which caused the trip relays to actuate and resulted in the system isolation.

In the LER supplement, NMPC revised the root cause to place the emphasis on insufficient precautions applied during the troubleshooting activities. Accordingly, NMPC adjusted their corrective actions to address the troubleshooting activities. These new corrective actions included a lessons-learned briefing with plant personnel that perform similar troubleshooting activities. Also, information

associated with this event was incorporated in the radiation monitor work history to help ensure that adequate precautions would be taken during future troubleshooting efforts.

The inspectors discussed the details of the lessons learned briefing with the Unit 1 Maintenance Manager and considered the information provided to be appropriate. The inspectors also discussed with the Maintenance Manager the fact that the lessons learned briefings were not provided to the technicians at Unit 2. Subsequently, the lessons learned information was provided to the appropriate Unit 2 technicians. This LER is closed.

III. ENGINEERING

E1 Conduct of Engineering (37551)

E1.1 General Comments

Using NRC Inspection Procedure 37551, the resident inspectors frequently reviewed design and system engineering activities, including justifications for operability determinations, and the support by the engineering organizations to plant activities.

E3 Engineering Procedures and Documentation (37551)

E3.1 Unit 2 Missed TS Required Logic System Functional Test of Loss of Power/Degraded Voltage Circuitry

a. Inspection Scope

NMPC identified that portions of the loss of power/degraded voltage circuitry associated with all three safety-related electrical divisions had not been tested as required by TS. The inspectors assessed the licensee's actions taken to address the missed TS surveillance requirement (TSSR). This assessment included a review of the SSS's logs and discussions with the on-watch SSS; observations of testing and discussions with the technicians performing the tests; and a review of applicable plant drawings and discussions with the system engineers.

b. Observations and Findings

On April 2, 1998, during the licensee's GL 96-01 review, NMPC identified that portions of the loss of power/degraded voltage circuitry associated with all three safety-related electrical divisions had not been tested, as required by TS. Specifically, TSSR 4.3.3.2 requires logic system functional test (LSFT) on the loss of voltage circuits for all three safety-related electrical divisions. Previous testing methodology failed to test the Division I and II function that changes the degraded voltage time delay during a LOCA. Specifically, without a LOCA, the degraded voltage circuit transfers the safety-related 4160 volt emergency switchgear from the off-site power supply to the EDG after a 30-second time delay; with a LOCA,

the time delay is only eight seconds. In addition, the past tests failed to verify proper operation of all contacts within the safety-related 4160 volt emergency switchgear supply breaker transfer sequencing circuitry used during a loss of voltage/degraded voltage condition.

Upon identification of the missed TSSR, Unit 2 system engineers documented the concern in a DER and provided the information to the control room. The SSS reviewed the DER and concluded that all three safety-related electrical divisions were inoperable. Since this was beyond the conditions covered by TS 3.3.3.b, Action 39, which addresses one channel being inoperable, the SSS entered TS 3.0.3, which requires a plant shutdown to be initiated within one hour. However, the SSS was able to delay the shutdown by implementing TS 4.0.3, which allows 24 hours to complete the missed surveillance test. The inspectors reviewed the SSS's logs and the applicable TS, and discussed the situation with the SSS, and concluded that the actions taken were appropriate.

NMPC revised their procedures and verified proper operation of the Division I and II degraded voltage time delay. In addition, NMPC developed a temporary test procedure and verified proper operation of all contacts within the safety-related 4160 volt emergency switchgear normal and alternate supply breakers loss of voltage/degraded voltage transfer sequencing circuitry. However, since the alternate offsite supply breakers to the emergency switchgear are not usually installed, NMPC could not test the portion of the circuitry associated with these breakers. Instead, NMPC used their tagging process to control installation of these breakers to ensure that they are tested before operation.

The inspectors observed a portion of the testing performed on the Division I transfer sequencing circuitry, and discussed the testing with the technicians and the system engineer. The testing was completed satisfactorily and the inspectors identified no concerns during the performance of the test. Additionally, through a review of the applicable plant drawings and test procedures, and a discussion with the system engineer, the inspectors verified that the completed testing was adequate to test the portions of the circuit in question. Furthermore, based on the discussion with the system engineer, the DER would be used to determine the root cause of this event and to track the corrective actions, including permanent changes to the loss of voltage testing procedures.

The failure to properly conduct LSFT for the Division I, II, and III 4.16 kV emergency buses loss of power/degraded voltage circuits was contrary to TS 4.3.3.2 and 10 CFR 50, Appendix B, Criterion XI, "Test Control". When tested on April 2, 1998, the circuit performed as designed, thus demonstrating logic system operability. This non-repetitive, licensee identified and corrected violation is being treated as a Non-Cited Violation consistent with Section VII.B.1 of the NRC Enforcement Policy. **(NCV 50-410/98-02-07)**

c. Conclusions

During the Generic Letter 96-01 review of safety-system logic testing, NMPC identified that portions of the loss of power/degraded voltage circuitry at Unit 2 were not being tested as required by TSs. Prompt and appropriate corrective actions were taken to demonstrate logic system operability. This licensee identified and corrected surveillance testing deficiency was not cited.

E7 Quality Assurance in Engineering Activities (37551)

E7.1 Unit 1 Control Room Emergency Ventilation System Operated Outside of the UFSAR Design Basis

a. Inspection Scope

On February 19, 1998, NMPC declared the Unit 1 control room emergency ventilation system (CREVS) inoperable upon discovering that the inlet damper was in an intermediate position, although the UFSAR stated the damper was to be set at 100 percent (%) open. Subsequent surveillance testing identified that the as-found CREVS fan flowrates, and the differential pressure (d/p) between the control room and adjacent spaces, were not within design specifications. As such, the CREVS was in a condition outside the design basis and under certain conditions potentially incapable of maintaining control room habitability specifications.

The inspectors observed licensee actions to evaluate and resolve issues related to the CREVS. The inspectors held discussions with Unit 1 management and system engineering, and observed licensee meetings to evaluate CREVS test results, establish system performance criteria, and determine system operability. The inspectors reviewed the details of the LER, the applicable DERs, and associated procedures.

b. Observations and Findings

System Description: The Unit 1 CREVS is designed to filter outside air before it is supplied to the control room. Upon receipt of a high radiation signal from one of the two radiation monitors on the ventilation intake, the system will realign from the normal unfiltered system to the emergency system, which filters the intake air through high-efficiency particulate air (HEPA) filters and charcoal adsorbers. Additionally, the CREVS is designed to maintain the control room atmosphere at a positive pressure relative to the surrounding spaces, such that potentially contaminated air will not leak into the control room.

Differential Pressure Between the Control Room and Adjacent Spaces

On January 9, 1998, the NRC observed that the normal control room ventilation system did not appear to maintain a positive d/p relative to the Unit 1 administration building. The inspectors questioned Unit 1 operations and system engineering

staffs on the requirements for maintaining a positive d/p between the control room and surrounding environment with normal control room ventilation in-service.

The Unit 1 UFSAR states that in order to prevent infiltration of potentially contaminated air, doors to the control room envelope are weatherstripped and penetrations are sealed to maintain a positive pressure of approximately one-sixteenth inch water gage. The system engineers informed the inspectors that, during normal plant operation, the positive d/p need only be maintained between the control room and the turbine building, since the turbine building was the only source of potentially contaminated air. However, during an event requiring actuation of the CREVS, the positive d/p would be required between the control room and all surrounding areas, including the outside atmosphere and the administration building. The inspectors considered the system engineering explanation to be appropriate.

Control Room-to-Turbine Building Differential Pressure Switch

During a subsequent review of the control room ventilation system, the system engineer identified that the pressure switch (DPIS-210-12), which provides an alarm in the control room upon a lowering control room-to-turbine building d/p, had not been incorporated into the routine calibration program, nor was the set point identified in Engineering Specification E-133. The system engineer initiated DER 1-98-0169. The failure to test the functionality of pressure switch DPIS-210-12 is a violation of 10 CFR 50, Appendix B, Criterion XI, "Test Control." (VIO 50-220/98-02-08).

The control room-to-turbine building low d/p alarm set point was established as a decreasing d/p. The system engineer noted that the current d/p was beyond the set point and the alarm was not in, indicating that the switch was out-of-calibration. The out-of-calibration switch was entered into the equipment status log (ESL). During the DER disposition, a procedure change was developed to require readings be taken on the control room-to-turbine building d/p gage (DPI-210-55) during routine shift checks. The DER corrective actions also required design engineering to determine if the current pressure switch was appropriate for the application and to establish a valid set point and tolerance. This is scheduled to be completed by October 1998. Although the out-of-calibration pressure switch was in the equipment status log (ESL), the inspectors questioned the ASSS as to the functionality of the associated control room annunciator. The annunciator was subsequently determined to be a control room deficiency and formally tracked as such. (see Section O2.2)

CREVS Operation and Testing Inconsistent with the UFSAR Description

During disposition of DER 1-98-0169, the licensee reviewed the UFSAR and applicable operating procedures. On February 17, the licensee discovered that the CREVS inlet damper was in an intermediate position which conflicts with the UFSAR stated damper position of 100% open. The CREVS was declared inoperable due to concerns associated with this damper position. On February 20, NMPC performed Procedure N1-ST-C9, "Control Room Emergency Ventilation Operability

Test;" to obtain CREVS as-found data. The surveillance test results were unsatisfactory. The flowrates for the CREVS fans were below design and the d/p's between the control room and adjacent spaces were also low.

On February 22, further test data was obtained with the inlet damper at 100% open. The CREVS fan flowrates and all d/p's were acceptable; however, the total ventilation system air flow was less than that described in the UFSAR. The UFSAR states that the ventilation system provides approximately 16,300 cubic feet per minute (cfm), but the test data indicated a system flow of approximately 12,000 cfm. Based upon the test results, NMPC concluded that the CREVS may have been unable to fulfill the safety function of mitigating the consequences of an accident by providing a habitable control room environment and subsequently notified the NRC in accordance with 10 CFR 50.72 (reference Event Number 33760).

The inspectors reviewed NMPC's 1989 safety evaluation (SE) No. 89-050, which had lowered the CREVS fan flowrate from the original design 3550 $\pm$10% cfm per fan to the current 2875 $\pm$10% cfm per fan. The flowrates were lowered due to the sealing of openings between the control room and adjoining spaces. The SE stated that with a lower fan flowrate, the required differential pressures would still be maintained. This change also established the inlet damper position at 100% open, to ensure that the control room ambient temperature and required differential pressures were maintained. The SE did not address that the sealing of the opening also reduced the total ventilation system air flowrate and the recirculation air flowrate to below the UFSAR design flow requirements.

The requirement for maintaining the inlet damper in the 100% open position, to ensure the CREVS would perform its design function, was not translated into plant operating and surveillance test procedures. Procedure N1-OP-49, "Control Room Ventilation System," allowed the operators to adjust the inlet and recirculation dampers to maintain control room ambient temperature. Procedure N1-ST-C9 directed the inlet and recirculation dampers to be repositioned during the surveillance test to achieve desired results. The inspectors determined that NMPC: (1) failed to ensure that the inlet damper was set at 100% open during normal system operation and surveillance testing; (2) did not understand the significance of the damper adjustment during and subsequent to conducting the surveillance test; and (3) failed to periodically verify total system flowrate and recirculation flowrate, as discussed in the UFSAR. The failure to properly maintain and test the CREVS is contrary to 10 CFR 50, Appendix B, Criterion III, "Design Control," and Criterion XI, "Test Control," and is a violation **(VIO 50-220/98-02-09)**.

NMPC concluded that this procedural inadequacy was a major contributor to the inoperability of the CREVS. Based upon their review, NMPC incorporated precautions into both the operating and surveillance test procedures to reflect the importance of maintaining damper position. Also, operator aids were posted at the dampers in the turbine building and at the remote switch controls in the control room to inform operators that following any CREVS damper adjustment, differential pressure verifications would have to be performed. The inspectors considered these actions appropriate.

Charcoal Filter Housing Heater

On March 5, the licensee identified that the 575-watt heaters surrounding the CREVS charcoal filter housing were electrically disconnected, and documented this concern on DER 1-98-0508. The heaters are discussed in the UFSAR and are depicted on the piping and instrumentation diagram. Th engineering staff informed the inspectors that the heaters provided conservatism in the design for moisture removal, that the heaters were not safety-related, and that the heaters had no direct system operability impact.

Engineering personnel performed a system walkdown and identified that the breaker feeding the heaters was closed. However, a disconnect box supplying power to a breaker for each of the four 575-watt heaters had the disconnect switch in the OPEN position with a label stating that previously installed 2-kilowatt heaters had been "retired-in-place." The inspectors learned that the 575-watt heaters were installed in the mid-1980's as replacements for the 2-kilowatt heaters. The failure to adequately maintain system design, in that the CREVS charcoal filter housing 575-watt heaters were not energized, is a violation of 10 CFR 50, Appendix B, Criterion III, "Design Control" **(VIO 50-220/98-02-10).**

c. Conclusions

NMPC's failure to properly maintain the control room emergency ventilation system design attributes and to properly test the system to demonstrate operability in accordance with the UFSAR is a violation of 10 CFR 50, Appendix B, Criteria III and XI. **(VIO 50-220/98-02-08,-09, and -10).** The immediate actions taken by the NMPC staff to initiate a detailed design review, implement interim compensatory measures, and to report this problem in accordance with 10 CFR 50.72 and 50.73 were determined to have been appropriate.

E7.2 Engineering Calculations in Support of Unit 1 CREVS Operability Determinations

a. Inspection Scope

As a follow-up to the degraded conditions of the Unit 1 CREVS, the inspectors reviewed the Engineering Support Analysis (ESA) and other engineering documents. The inspectors also discussed the issues with the Unit 1 Engineering and Plant Managers, and with the associated design and system engineers.

b. Observations and Findings

The inspectors reviewed the engineering documentation which defined the maximum allowable outside air temperature while the CREVS was in the degraded condition. This included the ESA, the Applicability Review (AR), and the associated calculations. Calculation #S10-210HV08, Revision 2B, concluded that the CREVS could be considered operable provided the outside air temperature was less than or equal to 60 degrees Fahrenheit ($\leq 60°F$). Due to the reduced ventilation flow rate, the calculation showed that the worst case control room temperature would be

79°F (UFSAR maximum value is 75°F). To provide additional operating margin, NMPC implemented a design change (DDC 1F00461A) and associated 10 CFR 50.59 safety evaluation (SE 98-005) to de-energize the ventilation intake ducting 15 kilowatt heater. Removal of the intake duct heater allowed maximum outside air temperature to be as high as 86°F, without exceeding the newly established inside air temperature of 79°F. The inspectors determined from discussions with station management that the UFSAR would be revised to reflect this calculated maximum control room temperature. NMPC analysis also confirmed that the control room temperature would need to exceed 104°F before equipment was affected. The inspectors confirmed that this was consistent with the station blackout and Appendix R analyses.

Further inspector review, and subsequent confirmation with the licensee's engineering staff, identified that a 1991 engineering calculation projected that, under worst case conditions (with design ventilation system air flow of 16,300 cfm), the control room ambient air temperature could reach 77°F. The failure to recognize that this 1991 calculation resulted in a condition that could potentially have exceeded the UFSAR maximum projected control room temperature value is a violation of 10CFR50, Appendix B, Criterion XVI, "Corrective Action." However, this violation of Appendix B is of minor safety consequence and is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy. **(NCV 50-220/98-02-11)** The Engineering Manager stated that NMPC was planning to re-baseline the control room heat load, determine the correct maximum control room temperature under worst case conditions, and then update the UFSAR.

c. <u>Conclusion</u>

The engineering calculations, supporting analyses, temporary modifications, and safety evaluations associated with the operability determination for the degraded condition of the Unit 1 control room emergency ventilation system (CREVS) were generally well prepared. The inspectors identified that 1991 calculations projected, under worst case conditions, that the CREVS may not have been able to maintain the control room temperature below the UFSAR value of 75°F.

E8 Miscellaneous Engineering Issues (90712, 92700, 92903)

E8.1 <u>(Closed) VIO 50-220/EA96-079-1023: Failure to Perform 10CFR50.59 Safety Evaluation in 1993 for the Unit 1 Blowout Panels</u>

In October 1993, NMPC identified a degraded condition associated with the Unit 1 reactor and turbine building blowout panels. Although this condition placed the plant outside the design bases, as described in the UFSAR, NMPC determined that the condition did not require a 10CFR50.59 safety evaluation. The details associated with this issue are contained in NRC IR 50-220/96-05, and were later discussed at a pre-decisional enforcement conference. As a result, a violation of 10CFR50.59 was issued via NRC letter to NMPC, dated June 18, 1996. NMPC provided their response to the violation in their July 16, 1996, letter to the NRC.

The inspectors considered the licensee's root cause analysis and corrective and preventive actions to be appropriate. NMPC revised procedure NIP-ECA-01, "Deviation/Event Report," to include improved procedural controls for 10CFR50.59 reviews of nonconformance or degraded conditions. The inspectors reviewed the applicable portions of NIP-ECA-01, Revision 13, and considered these controls to be adequate. This violation is closed.

E8.2 (Closed) VIO 50-220/EA96-079-2014: Failure to Address Human Performance Aspects of Blowout Panel Calculation Error through the DER Process

In October 1993, NMPC identified a degraded condition associated with the Unit 1 reactor and turbine building blowout panels. During a review of this issue in March 1995, NMPC identified a calculational error in the 1993 analysis. The subsequent re-analysis determined that the degraded condition was more severe than originally concluded. Based on the re-analysis, the licensee used the DER process to address the technical concerns associated with the degraded condition. However, the licensee failed to address the human performance aspect of the calculational error, as required by procedure NIP-ECA-01, "Deviation/Event Report." The details associated with this issue are contained in NRC IR 50-220/96-05, and were later discussed at a pre-decisional enforcement conference. As a result, a violation of TS 6.8.1, regarding procedure adherence, was issued via NRC letter to NMPC, dated June 18, 1996. NMPC provided their response to the violation in their July 16 and August 15, 1996, letters to the NRC.

The inspectors considered the licensee's root cause analysis and the corrective and preventive actions to be appropriate. Since the event in 1993, NMPC has revised procedure NIP-ECA-01, "Deviation/Event Report," to include enhanced procedural controls addressing human performance issues. The inspectors reviewed the applicable portions of NIP-ECA-01, Revision 13, and considered the controls in place to be adequate. Additionally, during the monitoring of day-to-day activities, the inspectors have observed an increased station management focus in addressing human performance issues during the resolution of DERs. This violation is closed.

E8.3 (Closed) URI 50-410/97-03-03: Inadequate Contingency in the Unit 2 Remote Shutdown Procedure to Ensure RHR Pump Minimum Flow Protection in the Event of a Control Room Fire

In May 1997, NMPC identified that the Unit 2 remote shutdown procedure did not provide adequate contingencies to ensure RHR pump minimum flow protection in the event of a control room fire. The licensee had identified this concern as a result of corrective actions associated with similar concerns described in NRC IR 50-410/97-05. Therefore, the inspectors assigned another unresolved item for this issue, pending the completion of the NRC staff's review.

By letter dated March 13, 1998, the NRC staff documented their review of these issues. Consequently, the failure to have adequate contingencies for a loss of RHR minimum flow valve position indication at the remote shutdown panel is a violation

of TS 6.8.1, regarding procedural adequacy. However, this licensee identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. **(NCV 50-410/98-02-12)**

E8.4 <u>(Closed) URI 50-410/97-04-03: Inadequate Procedure for the Remote Shutdown of Unit 2 During a Control Room Fire Coincident with a Loss of Off-Site Power</u>

In June 1997, NMPC identified that the Unit 2 Procedure N2-OP-78, "Remote Shutdown System," Revision 10, was inadequate to establish shutdown cooling during a control room fire coincident with a loss of offsite power (LOOP). In particular, Procedure N2-OP-78 required the operators to close the recirculation system pump discharge blocking valves at the respective circuit breakers. However, the licensee determined that these valves were powered from non-emergency power supplies, that would not be available during a LOOP unless damage repair actions were taken to restore power.

The licensee identified this concern as a result of corrective actions associated with similar concerns described in IR 50-410/97-05. Consequently, the inspectors assigned another unresolved item for this issue, pending the completion of the NRC staff's review.

In a letter to NMPC dated March 13, 1998, the NRC documented their review of these issues. As a result of this review, the inspectors concluded that the failure to have adequate contingency actions during a control room fire coincident with a LOOP is a violation of TS 6.8.1, regarding procedure adequacy. However, this licensee identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.
(NCV 50-410/98-02-13)

E8.5 <u>(Closed) IFI 50-410/97-06-02: Review of the Root Cause and Corrective Actions Associated with a Failed Flex-Hose at Unit 2</u>

In August 1997, the Unit 2 reactor was manually scrammed, and an Unusual Event was declared, due to an increasing drywell floor drain leak rate. Subsequently, NMPC identified that the leak was due to a failed flex-hose. At that time, the root cause evaluation was not complete. An inspector follow item (IFI) was opened to review the root cause analysis and any supplementary corrective actions.

An independent consultant was contracted by NMPC to conduct a destructive analysis of the failed flex-hose. The consultant determined that the most likely failure mechanism was low-cycle fatigue combined with stress corrosion cracking. This was consistent with NMPC's initial determination of intergranular stress corrosion cracking (IGSCC). Unit 2 engineering identified 26 flex-hoses in the drywell which are potentially susceptible to IGSCC. NMPC plans to replace all 26 hoses during the next refueling outage, scheduled to start May 2, 1998.

The inspectors reviewed the consultant's final report (MPM-1097406), and discussed the report with the consultant and Unit 2 engineering personnel. The

inspectors considered the root cause to be reasonable and the corrective actions to be appropriate. This item is closed.

E8.6 (Closed) LER 50-220/98-01: Violation of Secondary Containment During Maintenance

The event associated with this LER was described in NRC IR 50-220/98-01, Section E2.1. The inspectors conducted an in-office review and verified that the LER was completed in accordance with the requirements of 10CFR50.73. Specifically, the description and analysis of the event, as contained in the LER, were consistent with the inspectors' understanding of the event. The root cause, and corrective and preventive actions as described in the LER were reasonable. This LER is closed.

E8.7 (Closed) LER 50-220/98-02: Failure of Control Room Emergency Ventilation to Meet the Differential Pressure Requirements

The event associated with this LER was described in Section E7.1 of this IR. The inspectors verified that the LER was completed in accordance with the requirements of 10CFR50.73. Specifically, the description and analysis of the event, as contained in the LER, were consistent with the inspectors' understanding of the event. The root cause, and corrective and preventive actions as described in the LER were reasonable. This LER is closed.

E8.8 (Closed) LER 50-410/97-06-01: Plant Shutdown due to Rising Unidentified Leakage

The event associated with this LER was described in NRC IR 50-410/97-06, Section O2.1; the LER was initially reviewed in NRC IR 50-410/97-07. The supplement to the LER included the final root cause of the flex-hose failure, and additional corrective actions to prevent future failures (see Section E8.5 above). The inspectors conducted an in-office review and verified that the LER supplement was completed in accordance with the requirements of 10 CFR 50.73. This LER is closed.

E8.9 (Closed) LER 50-410/97-15-01: Opening Between Reactor Building and Reactor Building Auxiliary Bay

During the review of LER 50-410/97-15, as documented in NRC IR 50-410/97-12, the inspectors noted that the licensee described the opening as between secondary containment and the reactor building auxiliary bay. The inspectors considered the licensee's characterization of this opening to be misleading, since the auxiliary bay is inside secondary containment. The inspectors discussed this with the Unit 2 Engineering and Operations Managers, who acknowledged the misleading description. The licensee clarified the characterization in Supplement 1, describing the opening as between the reactor building and the reactor building auxiliary bay. The inspectors completed an in-office review of LER 50-410/97-15 Supplement 1, and found it acceptable. This LER is closed.

E8.10 (Closed) LER 50-410/98-03: Systems Outside the Design Basis Due to Inappropriate Seismic Criteria

a. Inspection Scope

The inspectors reviewed the LER, the related DER, and applicable portions of the UFSAR. Additionally, the inspectors observed a Station Operations Review Committee (SORC) meeting associated with the LER and discussed the event with the Unit 2 Engineering Manager.

b. Observations and Findings

On January 29, 1998, during a review of NRC Information Notice (IN) 97-71, "Inappropriate Use of 10 CFR 50.59 Regarding Reduced Seismic Criteria for Temporary Conditions," NMPC discovered that temporary lead shielding installed at Unit 2 during previous plant outages had placed the plant in a condition outside the design basis. The temporary shielding installed during refueling outages (RFOs) in 1992, 1993, 1995, and 1996, was incorrectly analyzed due to the engineering staff improperly using a probalistic risk analysis (PRA) argument. Specifically, the engineering staff used PRA to justify only analyzing the lead shielding with respect to the operating basis earthquake and did not include the more restrictive seismic stresses for a safe shutdown earthquake (SSE) as required by the UFSAR. Accordingly, when the SSE stresses were used in the analysis, the total stresses exceeded the maximum allowable stresses.

Upon identification of this problem, NMPC verified that they had properly analyzed the currently installed temporary shielding for seismic considerations. In addition, NMPC verified that the temporary shielding installed during the previous power operating cycle was acceptable. However, with respect to the previous outages, the licensee identified that the allowable stresses were exceeded for the following systems: residual heat removal system, high pressure core spray system, reactor recirculation system, and reactor water cleanup system. Preliminary reviews of the affected systems indicate that the systems, although outside the design basis, would have performed their safety functions had the design basis earthquake occurred while the temporary shielding was installed. Also, as described in the LER, NMPC intends to review other engineering programs to ensure that probabilistic risk arguments were being correctly applied.

Licensee assessment of this issue identified that, in 1991, during the analysis for the temporary shielding, the calculation preparers incorrectly used probabilistic arguments to justify less restrictive loading requirements. Furthermore, during the development of the associated 10CFR50.59 evaluations, the preparers and reviewers did not understand the basis of the calculations, and therefore inadequately reviewed the licensing basis documents. The failure to maintain the seismic qualification of plant systems is a violation of 10CFR50, Appendix B, Criterion III, "Design Control." However, this non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. **(NCV 50-410/98-02-14)**

The inspectors discussed the 10 CFR 50.59 evaluation process with the Unit 2 Engineering Manager and was informed that NMPC performed a sample review of other evaluations, with no additional discrepancies identified. Also, the inspectors learned that the evaluations of temporary shielding installed during outages at Unit 1 were properly completed in accordance with the licensing basis.

The inspectors verified that the LER was completed in accordance with the requirements of 10CFR50.73. Specifically, the description and analysis of the event, as contained in the LER, were consistent with the inspectors' understanding of the event. The root cause and corrective and preventive actions as described in the LER were reasonable. This LER is closed.

c. Conclusion

At Unit 2, probabilistic risk arguments were incorrectly used to justify less restrictive pipe stress limits in seismic qualification analyses for temporary shielding. Based on the analyses, the temporary shielding installed during refueling outages in 1992, 1993, 1995, and 1996, resulted in four systems exceeding allowable pipe stresses. This licensee identified and corrected violation was not cited.

E8.11 (Closed) LER 50-410/98-04: Missed TS Required Logic System Functional Test of Level 8 Trip of the Main Turbine

a. Inspection Scope

The inspectors reviewed the LER and related DER. Additionally, the inspectors observed an associated SORC meeting.

b. Observations and Findings

On March 2, 1998, while researching a question from another licensee, the Unit 2 staff identified that the current procedure for logic system functional testing (LSFT) of the main turbine trip on high reactor vessel water level (Level 8) failed to verify proper operation of the entire circuit. In particular, the once per 18 months TSSR 4.3.9.2 testing of the circuitry within the main turbine electro-hydraulic control (EHC) system was not tested per a test procedure. However, NMPC determined that during refueling outages, since October 1993, they had fortuitously and successfully tested the EHC circuitry, as part of a repetitive work order. Accordingly, the licensee identified that prior to October 1993, Unit 2 had not properly tested the EHC portion of the high reactor vessel water level main turbine trip circuitry. The failure to have performed a logic system functional test of the main turbine Level 8 trip function, in accordance with an established surveillance test procedure, is contrary to 10 CFR 50, Appendix B, Criterion XI, "Test Control." This licensee identified and corrected violation is being treated as a Non-Cited Violation consistent with Section VII.B.1 of the NRC Enforcement Policy. (NCV 50-410/98-02-15)

The inspectors noted that NMPC determined they had performed two previous LSFT reviews, but had missed this discrepancy. The first of the two NMPC reviews was in response to NRC Generic Letter (GL) 96-01, "Testing of Safety-Related Logic Circuits." NMPC determined the cause of these missed opportunities was poor work practices and a knowledge deficiency regarding the EHC system. Specifically, the previous LSFT reviews of this TSSR incorrectly characterized the EHC system as the "actuated device". Notwithstanding, as part of the GL96-01 review process NMPC required an independent senior engineer verification review of an initial reviewer's work, and believes this verification would have identified this deficiency.

The inspectors reviewed the associated DER and observed a SORC meeting pertaining to this issue with no concerns noted. The inspectors verified that the LER was completed in accordance with the requirements of 10CFR50.73. Specifically, the description and analysis of the event, as contained in the LER, were consistent with the inspectors' understanding of the event. The root cause and corrective and preventive actions as described in the LER were reasonable. This LER is closed.

c. Conclusions

Prior to October 1993, NMPC failed to perform TS logic system functional testing of the reactor vessel high water level main turbine trip at Unit 2. Fortuitously since October 1993, NMPC has tested this trip function per a repetitive work order. This licensee identified and corrected surveillance testing deficiency was not cited.

E8.12 Administrative Closure of Escalated Enforcement Items

The escalated enforcement items (EEIs) listed below are being administratively closed, due to the issuance of enforcement action (EA 97-229) via letter, dated March 13, 1998. All of the EEIs were classified as Non-Cited Violations, in accordance with the NRC Enforcement Policy, NUREG 1600, Section VII.B.3:

• EEI 50-220/97-05-01	NCV 50-220/98-02-16
• EEI 50-410/97-05-03	NCV 50-410/98-02-17
• EEI 50-410/97-05-05	NCV 50-410/98-02-18
• EEI 50-410/97-05-06	NCV 50-410/98-02-19
• EEI 50-220/97-05-02 & EEI 50-410/97-05-04	NCV 50-220 & 50-410/98-02-20
• EEI 50-410/97-09-01	NCV 50-410/98-02-21

IV. PLANT SUPPORT

Using NRC Inspection Procedure 71750, the resident inspectors routinely monitored the performance of activities related to the areas of radiological controls, chemistry, emergency preparedness, security, and fire protection. Minor deficiencies were discussed with the responsible management, and significant observations are detailed below.

R1 Radiological Protection and Chemistry (RP&C) Controls (71750, 83750)

R1.1 Radioactive Source Control at Unit 2

a. Inspection Scope

A review was performed of the control and issuance of radioactive calibration and check sources. Information was gathered by a review of procedural guidance, inspection of radioactive source storage facilities, and a review of source issuance records for 1998.

b. Observations and Findings

Procedures N2-RSP-10, "Accountability of Calibration and Check Sources," and N2-RSP-1SA, "Sealed Source Leakage/Contamination Test at Nine Mile Point Unit 2," contained clear guidance with respect to control, issuance, and leak testing of radioactive calibration and check sources. Storage cabinets for radioactive sources were securely locked and sources were stored in a neat and orderly fashion. Source issuance records for 1998 were reviewed and found to be up-to-date and complete. No deficiencies were identified.

c. Conclusion

Radioactive calibration and check sources were well controlled in that procedural guidance for the control and issuance of radioactive sources was clear, storage cabinets for radioactive sources were securely locked, sources were stored in a neat and orderly fashion, and source issuance records for 1998 were complete.

R1.2 Unit 1 Spent Fuel Pool Clean Out Project

a. Inspection Scope

A review was performed of radiological controls implemented for the Unit 1 1998 fuel pool clean out project. The project involved processing and packaging 32 control rod blades including stellite rollers and velocity limiters, five low power range monitors, vacuum cleaner filters, and irradiated hardware. Information was gathered by a review of controls to maintain radiation exposures as-low-as-is-reasonably-achievable (ALARA), by direct observations, and through discussions with cognizant personnel.

b. Observations and Findings

Radiological controls for the project were outlined in ALARA review 98-08, "Spent Fuel Pool (SFP) Clean-up Activities," and included a description of work scope, requirements for briefing/meeting, use of special tools/equipment, training and mockups, communications, contamination controls, and special dose reduction requirements and considerations. Industry events were effectively included throughout the review to emphasize potential radiological concerns and regulatory issues, a need for good communications, and strict adherence to radiological controls. A total of 2.5 person-rem was estimated for the project based on previous history. The ALARA review was thorough and included sound radiological controls.

The inspectors observed underwater loading of control rod blade parts into a cask liner. Health physics personnel maintained close and direct oversight of all fuel pool clean out activities. Underwater activities were monitored remotely with a camera and fuel pool water and video images had exceptional clarity.

c. Conclusion

Radiological controls for the Unit 1 1998 Fuel Pool clean out project were thorough and sound, and included lessons learned from industry events and close health physics oversight.

V. MANAGEMENT MEETINGS

X1 Exit Meeting Summary

At periodic intervals, and at the conclusion of the inspection period, meetings were held with senior station management to discuss the scope and findings of this inspection. The final exit meeting occurred on April 29, 1998, during this meeting, the resident inspector findings were presented. Based on the NRC Region I review of this report, and discussions with NMPC representatives, it was determined that this report does not contain safeguards or proprietary information.

X3 Management Meeting Summary

On March 27, 1998, the NRC met with representatives of Niagara Mohawk Power Corporation to discuss the new leadership training program being implemented at the Nine Mile Point site. The handouts from that meeting are included as Attachment 2 to this inspection report.

ATTACHMENT 1

PARTIAL LIST OF NMPC PERSONS CONTACTED

R. Abbott	Vice President, Nuclear Engineering
D. Barcomb	Manager, Unit 2 Radiation Protection
D. Bosnic	Manager, Unit 2 Operations
J. Burton	Manager, Training
H. Christensen	Manager, Security
J. Conway	Vice President, Nuclear Generation
G. Correll	Manager, Unit 1 Chemistry
R. Dean	Manager, Unit 2 Engineering
A. DeGracia	Manager, Unit 1 Work Control
S. Doty	Manager, Unit 1 Maintenance
K. Dahlberg	Plant Manager, Unit 2 (Acting)
G. Helker	Manager, Unit 2 Work Control
A. Julka	Director, ISEG
P. Mezzafero	Manager, Unit 1 Technical Support
B. Murtha	Manager, Unit1 Operations (Acting)
L. Pisano	Manager, Unit 2 Maintenance
N. Rademacher	Manager, Quality Assurance
R. Randall	Manager, Unit 1 Engineering
V. Schuman	Manager, Unit 1 Radiation Protection
R. Smith	Plant Manager, Unit 1
C. Terry	Vice President, Nuclear Safety Assessment & Support
C. Merritt	Manager, Unit 2 Chemistry
K. Ward	Manager, Unit 2 Technical Support
D. Wolniak	Manager, Licensing

INSPECTION PROCEDURES USED

IP 37551	On-Site Engineering
IP 60705	Refueling Preparations
IP 61726	Surveillance Observations
IP 62707	Maintenance Observations
IP 71001	Licensed Operator Requalification Program Evaluation
IP 71707	Plant Operations
IP 71750	Plant Support
IP 83750	Occupational Radiation Exposure
IP 90712	In-Office Review of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92700	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92901	Followup - Plant Operations
IP 92902	Followup - Maintenance
IP 92903	Followup - Engineering

Attachment 1 (cont.)

ITEMS OPENED, CLOSED, AND UPDATED

OPENED

50-410/98-02-01	NCV	LPCI configuration different from UFSAR
50-220/98-02-02	NCV	Failure to identify degraded conditions as control room discrepancies
50-220/98-02-03	NCV	Exceeded TS maximum allowed core thermal power
50-410/98-02-04	EEI	No licensed operator at-the-controls
50-220/98-02-05	VIO	Inadequate plant impact in work order package
50-410/98-02-06	NCV	Feedwater pump mechanical seal replaced without a procedure
50-410/98-02-07	NCV	Failure to perform LSFT for loss of power/degraded voltage circuits
50-220/98-02-08	VIO	Failure to calibrate and test d/p alarm for control room ventilation
50-220/98-09-09	VIO	Failure to maintain and test the CREVS per design
50-220/98-02-10	VIO	Failure to energize CREVS charcoal filter heaters
50-220/98-02-11	NCV	Calculated worst-case control room temperature greater than UFSAR limit, not updated
50-410/98-02-12	NCV	Failure to have adequate continency actions for remote shutdown procedure
50-410/98-02-13	NCV	Failure to have contingency actions for a control room fire coincident with a loss of offsite power
50-410/98-02-14	NCV	Failure to analyze temporary lead shielding for seismic qualifications
50-410/98-02-15	NCV	Failure to test main turbine EHC portion of Level 8 trip
50-220/98-02-16	NCV	Administrative closure of EEI 50-220/97-05-01
50-410/98-02-17	NCV	Administrative closure of EEI 50-410/97-05-03
50-410/98-02-18	NCV	Administrative closure of EEI 50-410/97-05-05
50-410/98-02-19	NCV	Administrative closure of EEI 50-410/97-05-06
50-220/ & 50-410/98-02-20	NCV	Administrative closure of EEI 50-220/97-05-02 & EEI 50-410/97-05-04
50-410/98-02-21	NCV	Administrative closure of EEI 50-410/97-09-01

CLOSED

50-410/96-01-01	URI	Contradiction between control room blackboard philosophy and Rosemont trip units

Attachment 1 (cont.)

CLOSED

50-220/96-07-05	URI	Revised post-maintenance-testing requirements not incorporated into an existing Unit 1 work package
50-220/96-07-08	URI	Post-job critique information not entered into work control database
50-220/ & 50-410/96-07-09	URI	Lubrication program problems
50-410/96-07-10	URI	Unit 2 feedwater pump mechanical seal replaced without a procedure
50-220/ EA 96-079-1023	VIO	Failure to perform 10CFR50.59 safety evaluation in 1993 for the Unit 1 blowout panels
50-220/ EA 96-079-2014	VIO	Failure to address human performance aspects of blowout panel calculation error through the DER process
50-410/97-03-03	URI	Inadequate contingency in the unit 2 remote shutdown procedure to ensure RHR pump minimum flow protection in the event of a control room fire
50-410/97-04-03	URI	Inadequate procedure for the remote shutdown of Unit 2 during a control room fire coincident with a loss of off-site power
50-410/97-06-02	IFI	Review of the root cause and corrective actions associated with a failed flex-hose
50-220/97-14-01	LER	Vent and purge system isolation during troubleshooting due to insufficient precaution applied
50-220/98-01	LER	Violation of secondary containment during maintenance
50-220/98-02	LER	Failure of Control Room Emergency Ventilation to Meet the Differential Pressure Requirements
50-220/98-03	LER	Power/Flow relationship technical specification violation (operation above rated power) due to inadequate managerial methods
50-410/97-06-01	LER	Plant shutdown due to rising unidentified leakage
50-410/97-15-01	LER	Opening between reactor building and reactor building auxiliary bay
50-410/98-02	LER	Violation of TS 6.2.2.b - No licensed operator at-the-controls
50-410/98-03	LER	Systems outside the design basis due to inappropriate seismic criteria
50-410/98-04	LER	Missed technical specification required logic system functional test of level 8 trip of the main turbine
50-410/98-02-01	NCV	LPCI configuration different from UFSAR

Attachment 1 (cont.)

CLOSED

50-220/98-02-02	NCV	Failure to identify degraded conditions as control room discrepancies
50-220/98-02-03	NCV	Exceeded TS maximum allowed core thermal power
50-410/98-02-06	NCV	Feedwater pump mechanical seal replaced without a procedure
50-410/98-02-07	NCV	Failure to perform LSFT for loss of power/degraded voltage circuits
50-220/98-02-11	NCV	Calculated worst-case control room temperature greater than UFSAR limit
50-410/98-02-12	NCV	Failure to have adequate continency actions for remote shutdown procedure
50-410/98-02-13	NCV	Failure to have contingency actions for a control room fire coincident with a loss of offsite power
50-410/98-02-14	NCV	Failure to analyze temporary lead shielding for seismic qualifications
50-410/98-02-15	NCV	Failure to test main turbine EHC portion of Level 8 trip
50-220/98-02-16	NCV	Administrative closure of EEI 50-220/97-05-01
50-410/98-02-17	NCV	Administrative closure of EEI 50-410/97-05-03
50-410/98-02-18	NCV	Administrative closure of EEI 50-410/97-05-05
50-410/98-02-19	NCV	Administrative closure of EEI 50-410/97-05-06
50-220/ & 50-410/98-02-20	NCV	Administrative closure of EEI 50-220/97-05-02 & EEI 50-410/97-05-04
50-410/98-02-21	NCV	Administrative closure of EEI 50-410/97-09-01

UPDATED

Attachment 1 (cont.)

LIST OF ACRONYMS USED

ALARA	As Low As Is Reasonably Achievable
ASME	American Society of Mechanical Engineers
ASSS	Assistant Station Shift Supervisor
cfm	cubic feet per minute
CFR	Code of Federal Regulations
COLR	Core Operating Limits Report
CRD	Control Rod Drive
CREVS	Control Room Emergency Ventilation System
CRSFT	Control Room Emergency Ventilation System
CSRW	Containment Spray Raw Water
DER	Deviation/Event Report
DWFD	Drywell Floor Drain
EA	Enforcement Action
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EEI	Escalated Enforcement Item
EHC	Electro-Hydraulic Control
EOPs	Emergency Operating Procedures
ESA	Engineering Supporting Analysis
ESF	Engineered Safeguards Feature
ESL	Equipment Status Log
GSO	General Supervisor of Operations
HEPA	High Efficiency Particulate Air
HPCS	High Pressure Core Spray
I&C	Instrumentation & Control
IFI	Inspector Follow Item
IGSCC	Inter-Granular Stress Cracking Corrosion
IN	Information Notice
IPAP	Integrated Performance Assessment Process
IR	Inspection Report
IST	Inservice Testing
LER	Licensee Event Report
LLRT	Local Leak Rate Test
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
LPCI	Low Pressure Coolant Injection
LSFT	Logic System Functional Testing
MW_{th}	Mega-Watts Thermal
NCV	Non-Cited Violation
NMPC	Niagara Mohawk Power Corporation
NRC	Nuclear Regulatory Commission
PMT	Post-Maintenance Test
psid	pounds per square inch differential
psig	pounds per square inch gage

Attachment 1 (cont.)

QA	Quality Assurance
RCIC	Reactor Core Isolation Cooling
RFO	Refueling Outage
RHR	Residual Heat Removal
RO	Reactor Operator
SDC	Shutdown Cooling
SE	Safety Evaluation
SF_6	Sulfur Hexa-Fluoride
SFP	Spent Fuel Pool
SORC	Station Operating Review Committee
SRO	Senior Reactor Operator
SSS	Station Shift Supervisor
TCV	Temperature Control Valve
TS	Technical Specification
TSSR	Technical Specification Surveillance Requirement
UFSAR	Updated Final Safety Analysis Report
Unit 2	Nine Mile Point Unit 2
Unit 1	Nine Mile Point Unit 1
URI	Unresolved Item
VIO	Violation
WO	Work Order
≤	Less than or Equal to
°F	Degrees Fahrenheit

ATTACHMENT 2

MANAGEMENT MEETING WITH

NIAGARA MOHAWK POWER CORPORATION

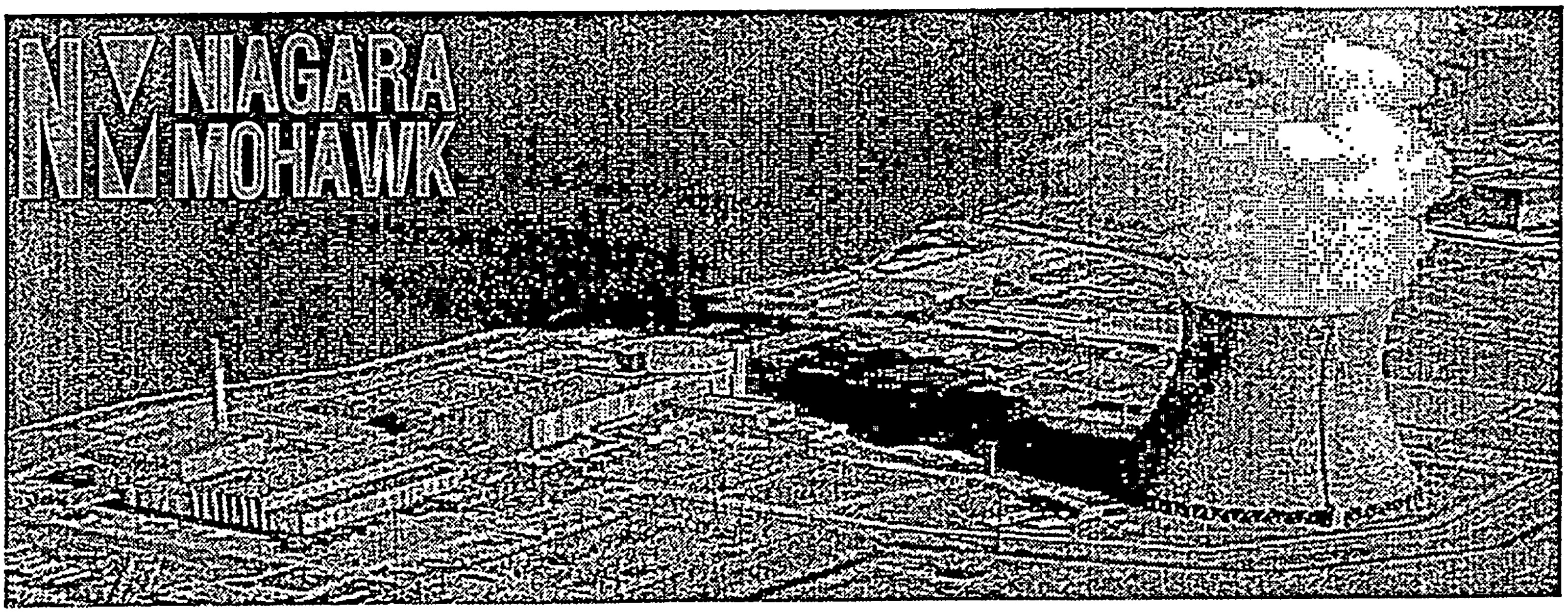
TO DISCUSS LEADERSHIP TRAINING

AT NINE MILE POINT

ATTACHMENT 2

NMPC-NRC
SENIOR MANAGEMENT MEETING

March 27, 1998

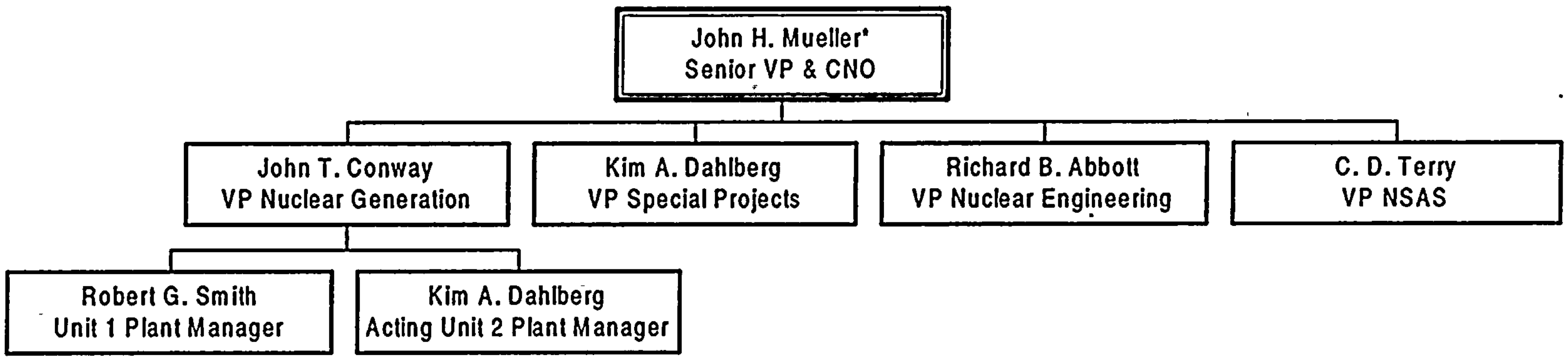


AGENDA

Introductory Remarks/ Organization Changes	J. H. Mueller
Human Performance Discussion	C. D. Terry/ R. B. Abbott
Leadership	J. T. Conway

ORGANIZATION CHART

NUCLEAR SENIOR MANAGEMENT TEAM



*Sr. VP & CNO is acting as VP & Gen. Mgr.
until Tech Specs approved

HUMAN PERFORMANCE

NIAGARA MOHAWK POWER CORPORATION

NINE MILE POINT NUCLEAR STATION

PROGRESS IN HUMAN PERFORMANCE

- Improved procedural compliance
- Thinking compliance
- Greater sense of accountability for actions
- More knowledgeable workforce
- Reduced operational events

WHY INCREASED FOCUS ON HUMAN BEHAVIOR?

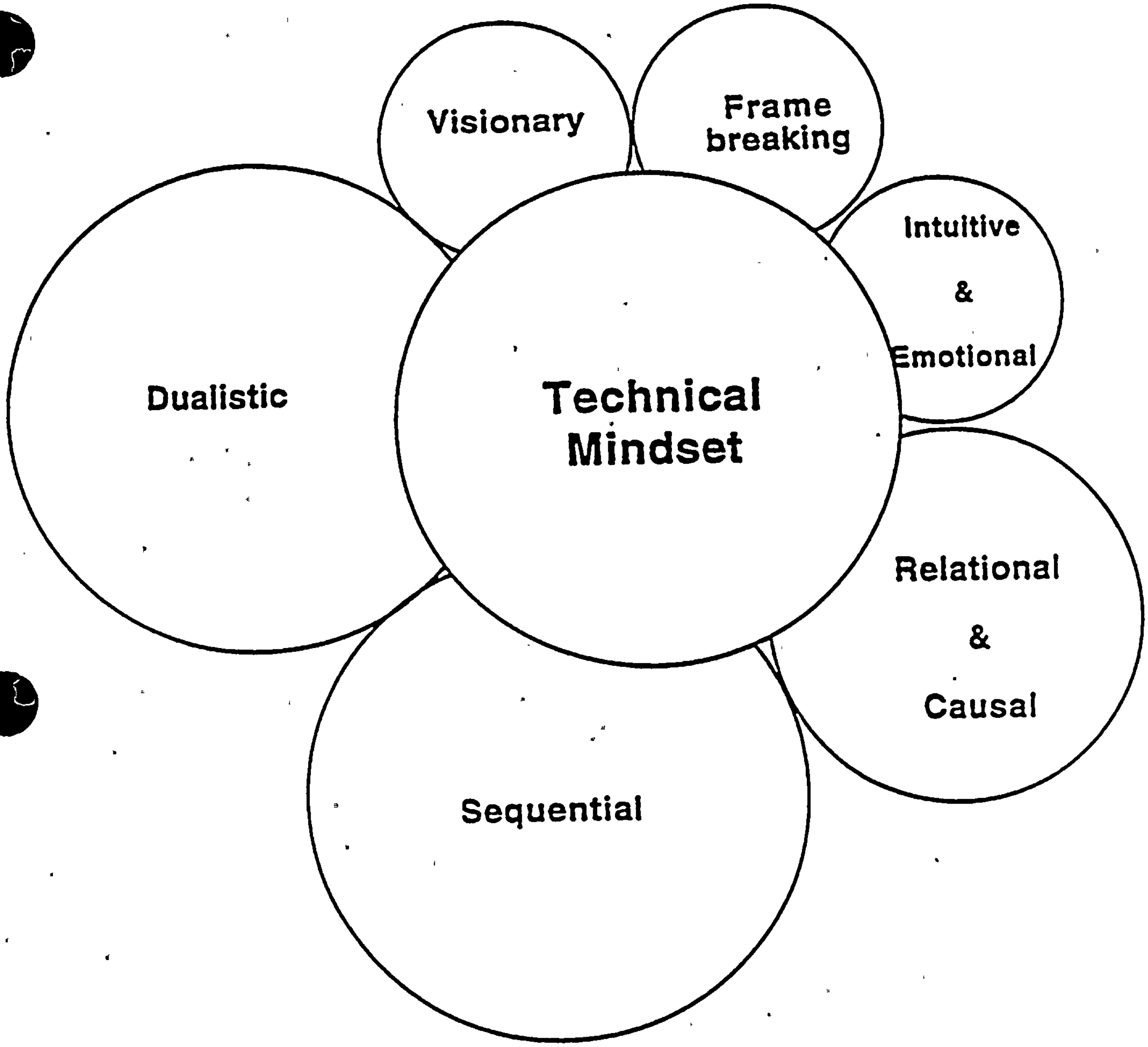
- Employee feedback
- Corrective action program issues
- Business planning offsite

NUCLEAR VISION

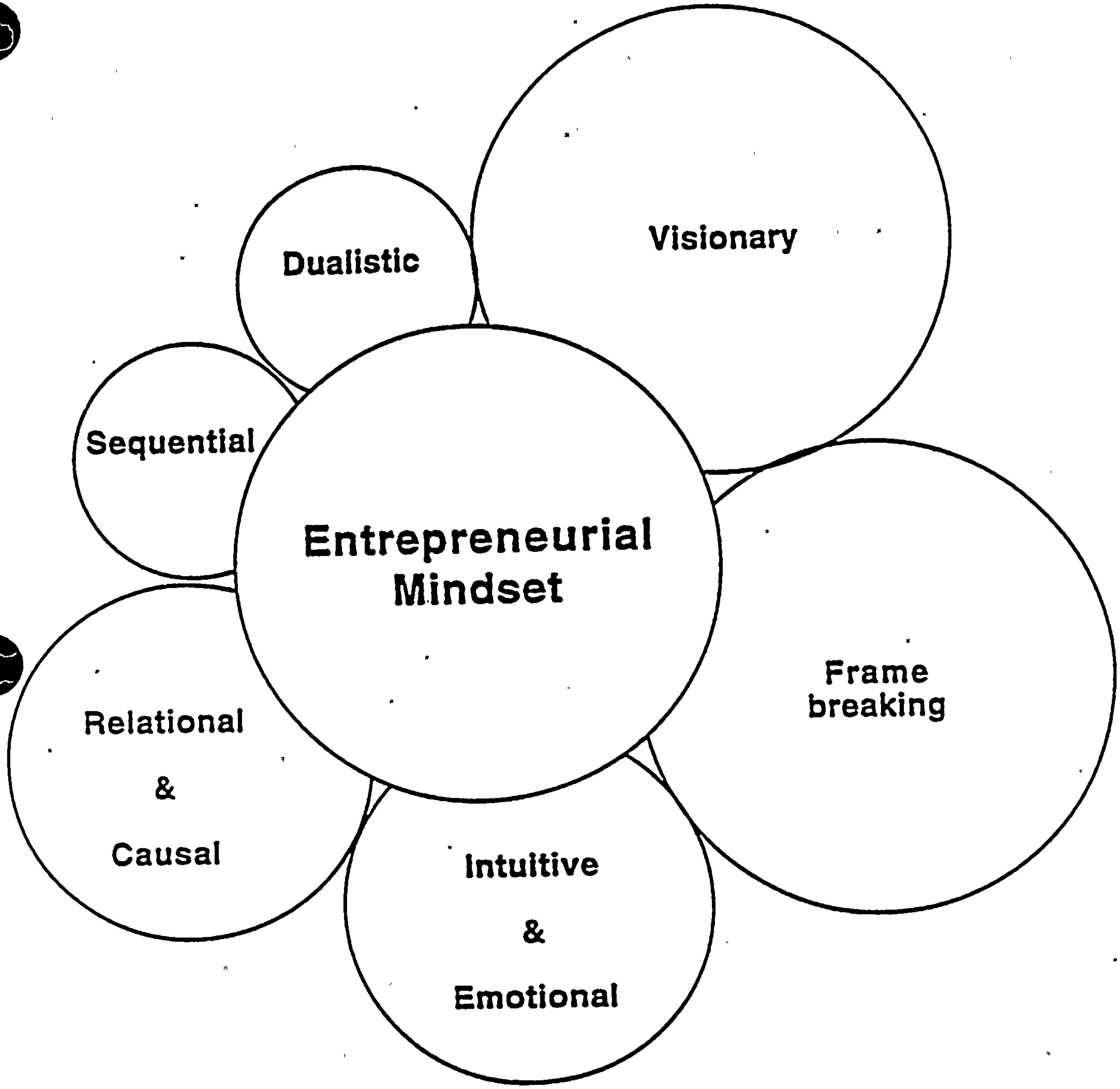
Foster a safety-conscious work environment where people create a highly valued generating station through superior work practices and ownership.

LEADERSHIP TRAINING

- Leadership mindsets



Dennis J. Gillen
Associate Dean
School of Management
Syracuse University
April 18, 1997



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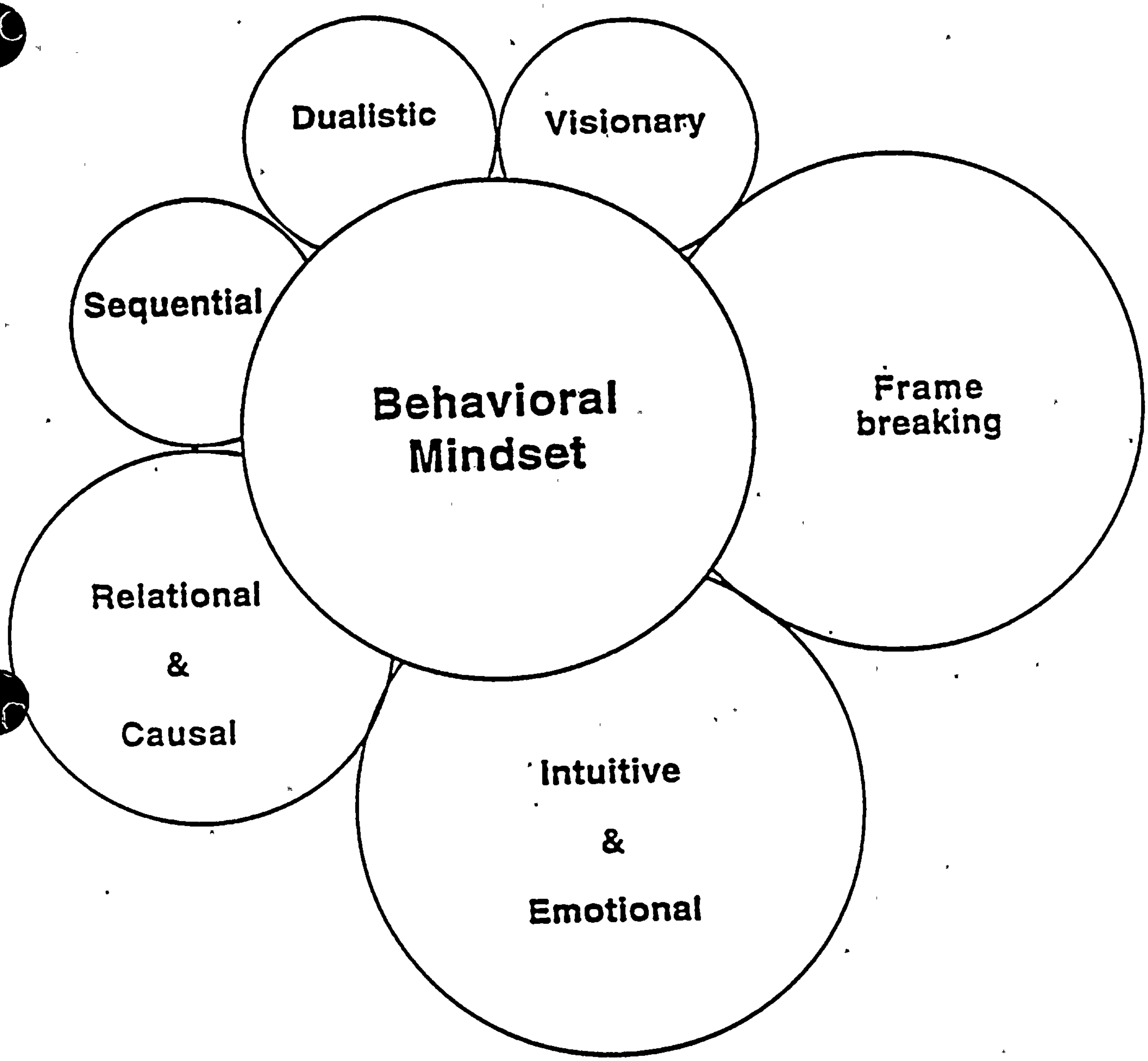

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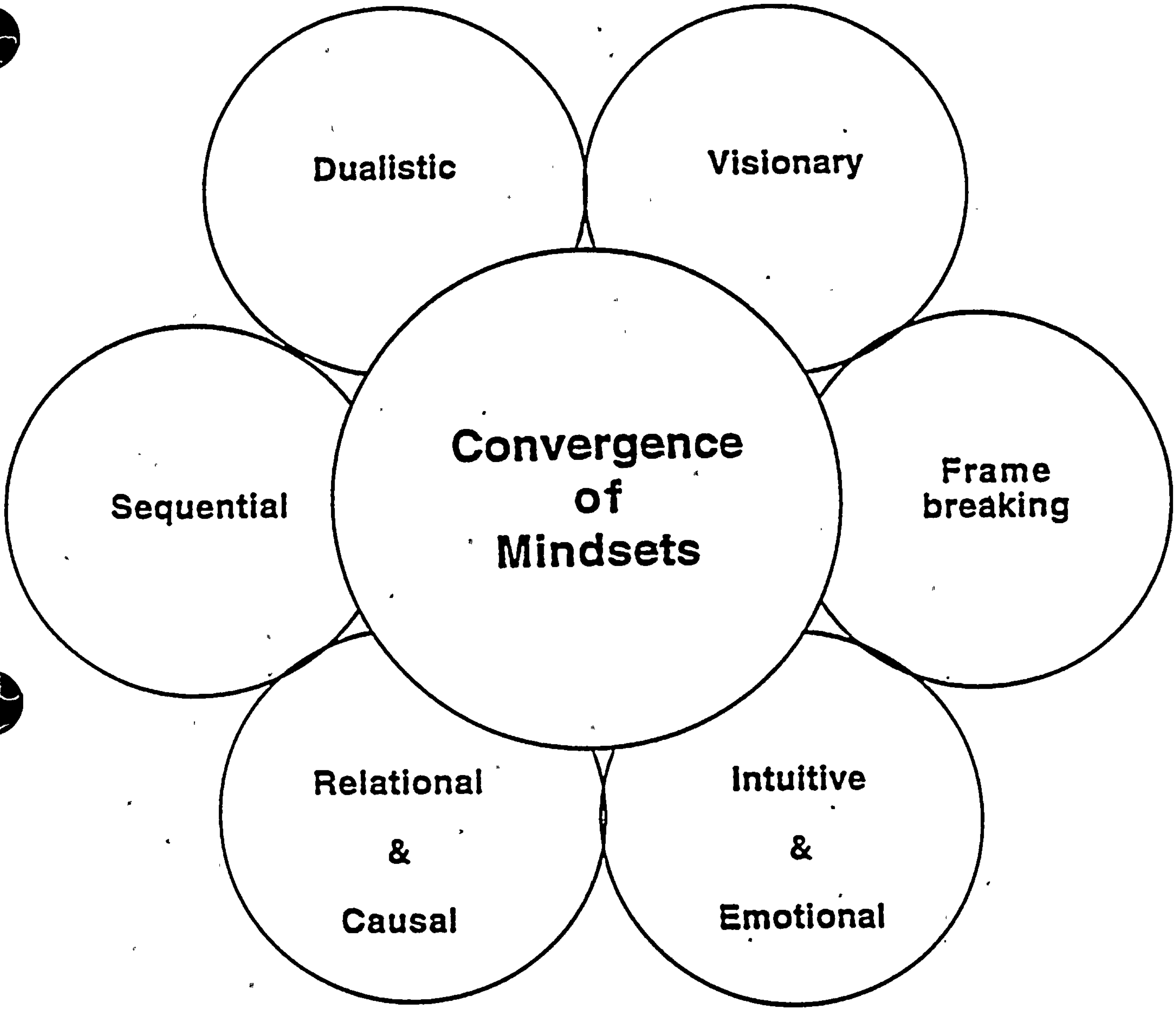

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LEADERSHIP TRAINING

- Leadership mindsets
- Transformational leadership

MANAGERS VERSUS LEADERS

Managers

~Processes

~Procedures

~Policies

~Plans and Budgets

~Controls and Solves Problems

Leaders

~Vision

~Values

~Mission

~Build Trust

~Motivates and Inspires

~Establishes Direction

~Produces Change

LEADERSHIP TRAINING

- Leadership mindsets
- Transformational leadership
- Senior Manager discussion

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