U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-369, 50-370
License Nos:	NPF-9, NPF-17
Report No:	50-369/98-08, 50-370/98-08
Licensee:	Duke Energy Corporation
Facility:	McGuire Nuclear Station, Units 1 and 2
Location:	12700 Hagers Ferry Road Huntersville, NC 28078
Dates:	July 12, 1998 - August 22, 1998
Inspectors:	S. Shaeffer, Senior Resident Inspector M. Sykes, Resident Inspector M. Franovich, Resident Inspector E. Girard, Regional Inspector (Section E8.1) H. Whitener, Regional Inspector (Section M3.1, M3.2) D. Forbes, Regional Inspector (Section R1.1, R1.2, R2.1, R2.2, R5.1) N. Stinson, Regional Inspector (Section R1.1, R1.2, R2.1, R2.2, R5.1)
Approved by:	C. Ogle, Chief, Projects Branch 1 Division of Reactor Projects

Enclosure 2

EXECUTIVE SUMMARY

McGuire Nuclear Station, Units 1 and 2
NRC Inspection Report 50-369/98-08, 50-370/98-08

This integrated inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covered a six-week period of resident inspection. Additional regional inspections were performed in the areas of inservice testing, radiation controls and chemistry, and motor operated valves.

Operations

- Following the identification of an auxiliary building ventilation design issue, the licensee's immediate corrective actions to address the issue and its associated Technical Specification requirements were adequate. An unresolved item was established pending further review of this issue. (Section O2.2)

- Accessible components of the Unit 1 auxiliary feedwater system were properly aligned. Material condition was adequate with the exception of an NRC identified, malfunctioning condensate drain for the steam supply to the Unit 1 turbine driven auxiliary feedwater pump. One negative observation was identified for the frequency of continuous drain inspections (only once per three refueling outages). (Section O2.3)

- Operators failed to maintain the required minimum reactor coolant system average temperature for criticality during an operator induced primary temperature transient. Operator performance was weak for not adequately controlling secondary (turbine loading) conditions to satisfy Technical Specification required minimum temperature for criticality during routine plant operations. (Section O4.1)

- A violation with two examples was identified for failure to adequately vent emergency core cooling system piping as required by plant procedure and Technical Specifications. The first example of the violation was caused by the licensee's failure to designate the proper vent valves used during system restoration. (Section E2.1)

Maintenance

- A repetitive failure of a Unit 1 main turbine throttle valve occurred. Repairs to correct the failed throttle valve actuator stem were effective and appropriate precautions were taken to minimize adverse impacts during the return to service. (Section M2.1)

- Inspections of the Unit 2 ice condenser intermediate deck doors bolting and upper ice basket flow passages were completed. Intermediate deck doors were free of ice and observed flow passages were clear. No operability concerns or Technical Specification non-conformances were identified. (Section M2.2)

- The program manual for the second ten year inservice testing interval contained the elements of the applicable Americal Society of Mechanical

Engineers/American National Standards Institute Operations and Maintenance Code Standards. (Section M3.1)

Engineering

- A violation with two examples was identified for failure to adequately vent emergency core cooling system piping as required by plant procedure and Technical Specifications. The second example of the violation was caused by the licensee's omission of valves required for venting in the monthly surveillance procedure. (Section E2.1)

- Initial engineering evaluations regarding past operability of the emergency core cooling systems did not consider all credible scenarios until identified by the NRC. (Section E2.1)

- Final evaluations of the problem with inadequate venting of the emergency core cooling system were considered adequate; although a number of assumptions were utilized in establishing past operability of the system. (Section E2.1)

- The overall implementation and conduct of the Engineering Support Program review board was detailed and probing and provided initiatives to improve the overall reliability of the system and the oversight of the system engineering function. This engineering improvement process was considered a strength. (Section E4.1)

- The licensee had completed thorough and technically sound resolutions of weaknesses previously identified during a Generic Letter 89-10 motor-operated valve inspection. (Section E8.1)

Plant Support

- The licensee effectively maintained controls for radioactive material and waste processing. (Section R1.1)

- The licensee's water chemistry control program for monitoring primary and secondary water quality had been effectively implemented, for those parameters reviewed, in accordance with Technical Specifications requirements and the Station Chemistry Manual for water chemistry. The collection of the samples was performed in accordance with the licensee's chemistry sampling procedure. (Section R1.2)

- Radiation and process effluent and environmental monitors were being maintained in an operational condition to comply with Technical Specification requirements and Updated Final Safety Analysis Report commitments. (Section R2.1)

- The meteorological instrumentation had been adequately maintained and the meteorological monitoring program had been effectively implemented. (Section R2.2)

- The chemistry management staff met the qualification requirements of Technical Specification 6.3.1. Also, the chemistry technicians had been properly trained for the duties they had been assigned as required by Technical Specification 6.4. (Section R5.1)

Report Details

Summary of Plant Status

Unit 1

Unit 1 began the inspection period at approximately 95 percent power due to a failed actuator stem on main turbine throttle valve number 1. On July 12, 1998, the unit was returned to approximately 100 percent power with three main turbine throttle valves operable. Unit 1 remained at 100 percent through the end of the inspection period.

Unit 2

Unit 2 operated at approximately 100 percent power throughout the inspection period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety-conscious. Specific event and noteworthy observations are detailed in the sections which follow.

O1.2 10 CFR 50.72 Notifications

a. Inspection Scope (71707)

During the inspection period, the licensee made the following notification to the NRC. The inspectors reviewed the event for impact on the operational status of the facility and equipment.

b. Observations and Findings

On August 7, 1998, the licensee notified the NRC regarding a loss of Emergency Notification System (ENS) phone line. The ENS line was established a short time later.

c. Conclusions

The inspectors concluded that the licensee reported the event in accordance with the requirements on 10 CFR 50.72.

O2 Operational Status of Facilities and Equipment

O2.1 Ice Condenser Surveillance - Notice of Enforcement Discretion 98-6-014

a. Inspection Scope (71707)

The inspectors reviewed the licensee's compliance with an ice condenser Technical Specification (TS) surveillance.

b. Observations and Findings

TS 4.6.5.1.b.3. requires, in part, that the licensee verify, by visual examination, that the accumulation of frost or ice on ice condenser flow passages is less than or equal to 0.38 inch. Specifically, the TS requires this inspection be performed on flow passages between ice baskets, past lattice frames, through the intermediate and top deck floor grating, or past the lower inlet plenum support structures and turning vanes. On August 7, 1998, the licensee determined that they may not have performed the required surveillance past the lower inlet plenum support structures and turning vanes. Based on this, the ice condensers were declared inoperable on both McGuire units. After reviewing the TS in more detail, the licensee subsequently interpreted that the TS surveillance did not specifically include these areas and was limited to the flow passages located above these components. The licensee then declared the ice condensers operable on August 8, 1998.

On August 12, 1998, during a conference call between the licensee and the NRC on the subject, the licensee was informed that TS 4.6.5.1.b.3 required visual inspections of flow passage areas in the lower plenum of the ice condensers. Based on this discussion, the licensee again declared both ice condensers inoperable on August 12, 1998.

On August 13, 1998, the licensee requested and was granted enforcement discretion regarding the failure to have performed inspection of the lower inlet plenums and turning vanes. Based on the granting of this discretion, the licensee declared both ice condensers operable on August 13, 1998. Additional NRC review of this issue will be performed during the review of LER 50-369/98-06, Non-compliance With Ice Condenser Technical Specification 4.6.5.1.b.3 Requirements. The NOED remains open until the licensee completes the required corrective actions.

c. Conclusions

The licensee identified a potential non-compliance with an ice condenser TS surveillance.

02.2 Unit 1 and Unit 2 Auxiliary Building Filtered Ventilation Exhaust System Inoperability

a. Inspection Scope (90712)

The inspectors evaluated licensee actions following identification of auxiliary building design features that had not been recognized in the licensee's training program and had not been incorporated into operational procedures.

b. Observations and Findings

On July 14, 1998, the licensee determined that past operational practices had resulted in the Unit 1 and Unit 2 auxiliary building filtered exhaust systems being inoperable when electrical power was isolated to one or more system fans. The licensee was unaware that de-energizing a fan resulted in inoperability of both units filtered exhaust systems. The licensee identified several instances where inoperability of the systems exceeded the TS 3.7.7 allowed outage time of 24 hours.

The licensee responded to this discovery by establishing an Operations Special Order directing operations personnel to declare both systems inoperable if a fan on either unit was electrically de-energized. The licensee also began a review of plant procedures to identify necessary procedure revisions to prevent recurrence. These corrective actions were included in Licensee Event Report 50-369/98-05 Revision 0. The inspectors evaluated the Operations Special Order and confirmed that appropriate guidance was available to prevent recurrence and ensure implementation of TS requirements.

Pending additional NRC review of this issue, this is identified as URI 50-369,370/98-08-01: Inoperable Auxiliary Building Ventilation System.

c. Conclusions

Following the identification of an auxiliary building ventilation design issue, the licensee's immediate corrective actions to address the issue and its associated TS requirements were adequate. A URI was established pending further review of this issue.

02.3 Unit 1 Auxiliary Feed Water (AFW) System Walkdown

a. Inspection Scope (71707)

The inspectors completed detailed inspections of selected portions of the Unit 1 AFW system to assess material conditions and verify proper system alignment. Field verification of valve position, electrical breaker alignment, and main control room indication were performed. Selected industry operating experience for AFW turbine driven pumps was also reviewed. Discussion with operations and engineering personnel was also performed.

b. Observations and Findings

Material condition of equipment was adequate with the exception of steam drains from the Unit 1 steam supply line for the turbine driven AFW (TDAFW) pump. During the system walkdown on August 3, 1998, NRC inspectors identified a normally warm drain line that was at approximately room temperature. The inspectors were concerned that improperly functioning drains may allow for excess accumulation of condensate in the steam line. Excess condensate could potentially water slug the TDAFW and trip the pump on overspeed when called upon to perform its safety function. Each McGuire TDAFW pump (one per unit) has three continuous one-inch drain lines off the steam supply line to the TDAFW pump. Each continuous drain line contains a 0.185 inch diameter orifice plate and a pair of isolation valves that allow drainage of condensate from steam that warms the line while the pump is in its normal standby condition. Engineering personnel used thermography on the line which indicated that the suspect line was at approximately 80 degrees Fahrenheit (°F). The remaining two continuous drains (downstream) were reading approximately 200 °F which was normal. On August 5, 1998, maintenance personnel disassembled the clogged line under work order number 98072203 and discovered a substantial amount of rust particles and foreign material (metal shavings). The metal shavings clogged the orifice. The line was placed back in service; however, the licensee expected the orifice to clog again since maintenance could not perform a high pressure flush of the line. The source of the metal shavings was not determined because maintenance personnel discarded the material. To flush the line, the licensee needed to develop a procedure for a high pressure blowdown (e.g. with the admit valves open). On August 12, 1998, following a TDAFW pump run, the orifice clogged again. Procedure development was in progress at the conclusion of the inspection period to clean the drain line.

The inspectors reviewed a sample of maintenance procedures to determine foreign material exclusion (FME) control on steam supply components such as admit valves and stop valve for the TDAFW. The licensee's Nuclear Site Directive (NSD) on housekeeping was reflected numerous times in these procedures. The inspector also questioned the system engineer on recent performance tests for indication of TDAFW turbine degradation. No adverse trend was noted and turbine performance was within the PT/1/A/4252/001, Number 1 TDAFW Pump Performance Test, limits for turbine speed.

The inspectors reviewed the licensee's corrective actions to Information Notice (IN) 93-51 regarding clogging of a steam trap and subsequent inoperability of a TDAFW pump at the South Texas Project plant. The licensee noted no corrective actions for this operating experience since the continuous drains are inspected once every three refueling outages and operators blow down other drains near the stop valve and turbine casing. The inspectors considered this as a weak response to the IN since (1) these small orifices can be clogged with minute debris as noted above, and (2) a mispositioned orifice isolation valve could also render a drain ineffective. Further, the inspectors noted the practice of shiftly blow down of the stop valve drains for approximately 30 seconds does not provide assurance that accumulated condensate in the steam line due to a clogged continuous drain (one closest to the stop valve) would be entirely removed. Additionally, if the last continuous drain was clogged, there is no visible method of verifying that water has been removed through the stop valve drain lines since the drain lines are hard piped and discharge beneath the waterline of the ground water sump. Engineering personnel have increased their inspection of these continuous drains; however, long-term corrective actions were under review at the end of the inspection period.

No system misalignments or other deficiencies were identified.

c. Conclusions

Accessible components of the Unit 1 auxiliary feed water system were properly aligned. Material condition was adequate with the exception of an NRC identified, malfunctioning condensate drain for the steam supply to the Unit 1 turbine driven AFW pump. One negative observation was identified for the frequency of continuous drain inspections (only once per three refueling outages).

O4 Operator Knowledge and Performance

O4.1 Unit 1 Startup - Minimum Temperature for Criticality Not Maintained

a. Inspection Scope (71707)

The inspectors reviewed the facts and circumstances related to Unit 1 operation below the minimum temperature for criticality. Reactor power and coolant reactor system (RCS) temperature plots from the plant computer were reviewed and discussions were held with operations personnel on this event.

b. Observations and Findings

On July 1, 1998, the Unit 1 RCS average temperature (T_{avg}) fell below the Technical Specifications 3.1.1.4 required minimum temperature of 551°F for approximately five minutes with reactor power at approximately 9 percent. Operators were loading the turbine generator and did not adequately control load to maintain T_{avg}, thereby resulting in the temperature transient. The lowest indicated T_{avg} reached during this period was approximately 548 °F. The transient duration was approximately 20 minutes. Reactor coolant temperature was restored to expected temperatures following operator response to RCS low temperature alarms and immediate corrective action to cut turbine load. The inspectors verified that the associated TS action statement time limit (i.e. restore T_{avg} within its limits within 15 minutes) was not exceeded.

The inspectors discussed this event with operations management and reviewed portions of station records for recent previous occurrences. A review of station records indicated that no similar events had occurred.

A root cause evaluation of the event was in progress at the end of the inspection period to determine what long-term corrective actions would be necessary to prevent recurrence.

c. Conclusions

Operator performance was weak for not adequately controlling secondary (turbine loading) conditions to satisfy TS required minimum temperature for criticality during a Unit 1 startup; however, the associated TS action statement time limit was not exceeded.

O8 Miscellaneous Operations Issues

O8.1 (Closed) LER 50-369/98-01: Inadvertent Removal of a FWST (Refueling Water Storange Tank) Channel From Tripped Condition and a Containment Pressure Control System (CPCS) From Start Permissive Condition.

On February 27, 1998, the licensee submitted LER 50-369/98-01, Revision 0, concerning inadvertent removal of an inoperable FWST level channel from the tripped condition and inadvertent removal of a CPCS channel from the start permissive condition. The NRC technical concerns for these events were identified in Inspection Report 50-369,370/98-02 as a URI. The URI was closed in Inspection Report 50-369,370/98-03 as NCV 50-369,370/98-03-03: Inadequate Procedures Results in Non-compliance With Technical Specifications for Inoperable Engineered Safety Feature Instrumentation for Refueling Water Storage Tank Level and Containment Pressure Control System. The inspectors reviewed the remaining outstanding procedures that were under technical hold and verified that appropriate changes were made to prevent recurrence of the events. This LER is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (61726, 62707)

The inspectors reviewed the following maintenance and/or surveillance activities:

Procedure/Work Order	Title
IP/0/B/3150/002	Peak Shock Recorder and Annunciator Calibration
IP/0/B/3150/003	TS-3A Triaxial Seismic Switch Calibration
PT/1/A/4600/008	Surveillance Requirements for Unit Heatup
PT/2/A/4200/014A&B	Ice Condenser Intermediate Deck Door

	Inspection
98030445	2VPVA12A Re-Route Isolation Valve
98075607	Inspect Unit 2 Ice Condenser Deck Door Bolts
98075608	Ice Condenser Walk-Thru Surveillance
98075609	Ice Condenser Weekly Surveillance PM

b. Observations and Findings

The inspectors witnessed selected surveillance tests to verify that approved procedures were available and in use; test equipment was calibrated; test prerequisites were met; system restoration was completed; and acceptance criteria were met. In addition, the inspectors reviewed or witnessed routine maintenance activities to verify, where applicable, that approved procedures were available and in use, prerequisites were met, equipment restoration was completed, and maintenance results were adequate.

c. Conclusions

Observed routine maintenance and surveillance activities were completed satisfactorily.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Unit 1 Throttle Valve Stem Failure

a. Inspection Scope (62707)

The inspectors evaluated licensee actions in response to a second main steam throttle valve actuator stem failure within approximately 12 months.

b. Observations and Findings

On July 11, 1998, control room operators received indications of a closed number 1 throttle valve and a Tavg/reference temperature (Tref) mismatch, to which control rods responded in automatic to maintain reactor power below rated thermal power limits. Operators were dispatched to the Unit 1 main turbine and confirmed that the number 1 throttle valve was closed. The actuator stem had failed, resulting in a fast closure of the valve from spring force. The closure of one throttle valve is not a turbine trip signal; therefore, no reactor trip signal was generated.

This was the second Unit 1 throttle valve actuator stem failure in approximately 12 months. Both failures have been attributed by the licensee to high cycle/low amplitude fatigue.

The licensee previously developed repair plans to perform online repairs. The licensee completed the repair and reduced reactor power prior to returning the stop valve to its normal position. The power reduction provided adequate margin in the event the valve went to the full open position once energized. This minimized the potential for exceeding the licensed rated thermal power output. The valve was returned to service without difficulties.

The licensee, aware of the potentially degraded condition, had instituted a program to replace the actuator stems on a rotating basis during upcoming refueling outages. The licensee is evaluating the current replacement schedule for the remaining actuator stems.

c. <u>Conclusion</u>

A repetitive failure of a Unit 1 main turbine throttle valve occurred. Repairs to correct the failed throttle valve actuator stem were effective and appropriate precautions were taken to minimize adverse impacts during the return to service.

M2.2 <u>Unit 2 Ice Condenser Inspection</u>

a. <u>Inspection Scope (71707)</u>

Following the identification of potential operability concerns at a similar nuclear station, the inspectors performed inspections of the ice condenser intermediate deck door assemblies and upper ice basket sections.

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

On August 19, 1998, the inspectors performed at power inspections of the ice condenser intermediate deck door assemblies and upper ice basket areas to verify no flow path blockage and proper installation of intermediate deck door assemblies. The inspectors inspected ice baskets from several bays. No flow passage blockage was noted and no damage was noted to call into question the operability of the ice condenser. The inspectors verified that no accumulation was present at the doors to prevent full opening during a design basis event.

c. <u>Conclusions</u>

No operability concerns or TS non-conformances were identified during inspections of ice condenser intermediate deck doors bolting and upper ice basket flow passages.

M3 Maintenance Procedures and Documentation

M3.1 Inservice Testing Program

a. Inspection Scope (73756)

The inspectors performed an overview inspection of portions of the inservice testing (IST) program and reviewed portions of the second ten year interval Program Manual to verify that components in the program were identified and that the required testing, frequency of testing, test parameters and justification for deferrals were specified. A limited scope review was performed for the auxiliary feedwater system.

b. Observations and Findings

The inspectors determined that the program manual was referenced to the American Society of Mechanical Engineers (ASME) Section XI Boiler and Pressure Vessel applicable codes. The licensee has implemented the ASME/American National Standards Institute (ANSI) Operations and Maintenance (OM) Standards endorsed by 10CFR50.55a and ASME Section XI Boiler and Pressure Vessel Code, Subsections IWP and IWV. 10CFR 50.55a(b) references the ASME/ANSI OM standards 1987 edition and OMa 1988 addenda as the applicable standards for the current ten year interval IST program at McGuire. Elements of the Code OM standards were incorporated into the Manual and in plant procedures. The systems included in the program were identified. Pump and valve tables identified the components in the IST program, type of tests to be performed, test frequencies, test procedures and test deferrals.

c. Conclusions

The Program Manual for the second ten year IST interval contained the elements of the applicable ASME/ANSI Operations and Maintenance (OM) Code Standards.

M3.2 Limited System Scope Review

a. Inspection Scope (73756)

The inspectors performed a limited review of the auxiliary feedwater system to verify that the licensee had established appropriate procedures and was following an acceptable program.

b. Observations and Findings

The inspectors reviewed the auxiliary feedwater system program and plant drawings and verified that all valves affecting the flow path of this system were tested in the IST program. The inspectors verified that the licensee had developed procedures for the performance of the required quarterly pump, valve stroke time, valve exercise tests, full flow exercising, and backflow testing of the check valves.

The inspectors found the test procedures generally adequate. Adequate instructions, acceptance criteria and actions to be taken if the component does not meet the acceptance criteria were specified and were consistent with the Code OM Standards.

c. Conclusions

The inspectors concluded that the procedures reviewed contained adequate instructions and acceptance criteria.

III. Engineering

E2 Status of Engineering Facilities and Equipment

E2.1 Gas Void Discovered in Unit 2 Emergency Core Cooling System (ECCS) Piping

a. Inspection Scope (71707, 37551)

The inspectors reviewed circumstances regarding gas identified in the Unit 2 ECCS piping with the unit at 100 percent power. The inspectors reviewed the potential effect of the gas on current and past ECCS operability, the method of discovery, the licensee's root cause evaluation, and the regulatory and safety significance.

b. Observations and Findings

On May 27, 1998, the licensee revised PT/2/A/4200/019, Unit 2 ECCS Pumps and Piping Vent, Revision 13, to include several high point vents that were previously omitted. Valve 2ND-77 and five additional high point vents were identified by engineering, as having been previously omitted from the surveillance. On June 5, 1998, during performance of PT/2/A/4200/019, Unit 2 ECCS Pumps and Piping Vent, Revision 13, gas was detected at high point vent valve 2ND-77. During the evolution, operators observed 45 seconds of gas venting with this valve one quarter turn open. Subsequent licensee analysis concluded that the void was approximately 6.57 cubic feet under RWST static head conditions. Vent valve 2ND-77 is located in a loop seal piping configuration upstream of check valve 2ND-71 and valve 2NI-136B.

The gas was located in a section of ECCS piping that is required to be full of water in order to ensure that there are two independent and redundant ECCS subsystems. The ECCS subsystems are designed to ensure sufficient emergency core cooling to limit peak cladding temperatures within acceptable limits for all postulated Loss of Coolant Accident (LOCA) scenarios. Each subsystem consists of a centrifugal charging pump, safety injection pump, residual heat removal (RHR) pump, RHR heat exchanger and a suction flow path from the RWST. During a LOCA, these subsystems take a suction from the RWST. Upon depletion of the RWST inventory, the residual heat removal pumps automatically realign to the containment sump during the recirculation phase of operation. The intermediate and high head safety injection pump suctions are manually realigned to the discharge of the RHR pumps. This evolution is referred to as the "piggyback" mode of operation and is described in the plant emergency operating procedures (EP/2/A/5000/ES-1.3, Transfer to Cold Leg Recirculation). During the piggyback mode, two normally closed motor operated valves, 2ND-58A and 2NI-136B (A and B train, respectively) are manually opened from the control room to allow either RHR pump to provide a suction to both intermediate and high head safety injection pumps.

Apparent Causes and Regulatory Significance

The inspectors reviewed the adequacy of the licensee's periodic performance of TS required ECCS piping venting per TSSR 4.5.2.b.1. This surveillance requires, in part, that each ECCS subsystem shall be demonstrated operable, at least once per 31 days by verifying that the ECCS piping is full of water by venting the ECCS pump casings and accessible discharge piping high points, unless the pumps and associated piping are in service or have been in service within 31 days. The inspectors considered implementation of TSSR 4.5.2.b.1 per McGuire procedure PT/2/A/4200/019, Revision 12, Unit 2 ECCS Pumps and Piping Vent, was inadequate to ensure that the ECCS piping was full of water during monthly system venting performed since December 17, 1997 through June 5, 1998. Specifically, accessible discharge piping high point vent 2ND-77 was not included in the venting process. As a result, the gas void in the vicinity of 2ND-77 was not detected during performance of this surveillance. The failure to include the accessible high point vent valves in procedures as require by TS is one example of a violation of NRC requirements. This is identified as Violation 50-370/98-08-02: Failure to Adequately Vent ECCS Piping - Two Examples.

The licensee determined that the gas, that was detected on June 5, 1998, was introduced into the ECCS piping during modification work per MGMT-7858 to install a bonnet equalization line on valve 2NI-136B. This work was performed during the Unit 2 End of Cycle 11 steam generator replacement project (SGRP)/refueling outage, which was completed on December 17, 1997. During the work activities, several drill bits broke off in the valve bonnet which later required the associated piping to be drained for foreign material retrieval. The licensee concluded that the affected piping was not properly filled and vented following this outage modification. During restoration of this portion of piping, operations personnel failed to identify the appropriate high point vents to ensure adequate refill of the system in as required by OMP 7-1, Removal and Restoration (R&R) Requirements. The failure to adequately identify the appropriated high point vents is a second example of Violation 50-370/98-08-02, Failure to Adequately Vent ECCS Piping - Two Examples.

Corrective Actions

Once the licensee determined that certain high point vent valves had not been included in PT/2/A/4200/019, the procedure was revised and performed on June 5, 1998. Following initial discovery of gas at 2ND-

77, licensee engineering also instructed operators to perform an additional check for gas at the upstream high point vent valve, 2ND-83. A negligible amount of gas was detected. Based on this, the licensee concluded that the ECCS piping was water solid. The licensee documented the discovery of gas at 2ND-77 via PIP 2-M98-1767, generated on June 5, 1998. This condition was initially screened as a less significant event (LSE). LSEs do not require an operability evaluation.

On June 8, 1998, the inspectors reviewed the PIP and requested a meeting with engineering personnel to discuss specific concerns regarding: 1) the past operability of the ECCS; 2) the appropriateness of the initial evaluation of the condition as an LSE; and 3) the scope of corrective actions. The licensee acknowledged the inspectors' concerns and upgraded the PIP to a more significant event (MSE) to include an operability determination.

Based on discussions with the inspectors, the licensee also performed ultrasonic testing (UT) of the piping near 2NI-136B and determined that a 0.215 cubic foot void existed downstream of valve 2NI-136B. This gas could not be vented during power operations. The licensee evaluated the potential impact of the gas accumulation and determined that this small void would not affect system operability. Specifically, the 0.215 cubic foot void would remain intact to the pump suction and the pump performance would not be significantly affected.

The licensee stated that no voids were detected during the performance of the expanded Unit 1 ECCS venting surveillance which was performed in May 1998.

Past Operability

The McGuire intermediate and high head pumps are horizontal, multi-staged rotating impeller pumps. Based on system and pump design, the inspectors questioned the licensee concerning past operability. The inspectors had specific concerns regarding the effect the entrained gas would have on the ECCS system during certain design basis accidents. By letter dated June 10, 1998, the vendor (Ingersoll-Dresser) provided the licensee an initial evaluation of the capability of these multi-stage pumps. The vendor summarized the capability of the pumps for operating with: 1) entrained flow; and 2) a single bubble or slug flow. For a homogeneous mixture of gas bubbles in a liquid stream, the vendor stated that degradation could begin at 2 percent gas by volume. The vendor did not recommend pump operation with more than 5 percent gas by volume. For slug flow, the vendor did not identify an acceptable quantity of gas for continued operation.

On July 9, 1998, the licensee completed the past operability review of the ECCS with the 6.57 cubic feet of gas found at 2ND-77. The evaluation was documented in calculation MCC-1223.11-00-0032. Small break LOCA and large break LOCA scenarios were evaluated. The licensee concluded that the 6.57 cubic feet of gas would not have had an adverse affect on system operability. This conclusion was based on evaluation of the estimated volume and a Duke Energy ECCS flow modeling program known as the Woods model. The model provided ECCS flow rates and pump suction conditions for various alignments. Using engineering judgement, the licensee assumed that the void would initially be compressed under RHR pump discharge pressure and subsequently split in direct proportion to the suction piping flow rates. The evaluation concluded that the volume of gas to any ECCS pump would not cause air binding.

On July 10, 1998, the inspectors reviewed the completed calculation and identified other design basis accident scenarios not evaluated by MCC-1223.11-00-0032. The inspectors questioned the licensee on several additional small break LOCA (SBLOCA) scenarios. These SBLOCA scenarios involved RCS pressures greater than 1600 pounds per square inch gauge (psig). Under these conditions emergency procedures instruct operators to secure the intermediate pumps prior to initiating cold leg recirculation. The following table details the cases not initially evaluated by the licensee.

SBLOCA with RCS Pressure Greater Than 1600 psig
(i.e. no SI pumps running)

Case #	Single failure	High Head Injection pump status	status of gas void upstream of 2NI-136B
1	2ND58A fails to open	2A running 2B running	100 percent of gas to both CCP pumps
2	1 high head injection pump fails or unavailable	2A(2B) idle 2B(2A) running	100 percent to one pump, mixed with flow from 2ND58A (assuming 2ND58A is opened before 2NI136B)
3 (LOOP/LOCA)	2A EDG does not provide emergency power	2A idle 2B running	100 percent of gas to 2B high head injection pump (no mixing from A RHR)

The licensee subsequently reviewed the above cases and on July 14, 1998, revised calculation MCC-1223.11-00-0032 to include an evaluation of these SBLOCA cases. For these cases, the licensee concluded that the 6.57 cubic feet gas void would not adversely impact the ECCS pumps. These conclusions were based on the assessment of system flow rates and the buoyancy effects. The licensee also concluded that the amount of gas to a single high head pump would be reduced due to compression from RHR pump discharge pressure and stripping effects from idle branch lines and other piping interferences. The inspectors noted that the licensee did not specifically analyze for the percentage of potential gas entrainment or the length of time the pump may operate with entrained gas. However, the NRC did not dispute the final assessment provided by the licensee regarding past ECCS system operability.

c. Conclusions

A violation with two examples was identified for failure to adequately vent ECCS piping as required by plant procedure and TS. The violation was caused by the licensee's omission of valves required for venting in the monthly surveillance procedure and the licensee's failure to designate the proper vent valves used during system restoration.

Initial engineering evaluations regarding past operability of the emergency core cooling systems did not consider all credible scenarios until identified by the NRC.

Final evaluations of the identified problem were considered adequate; although a number of assumptions were utilized in establishing past operability of the system.

E4 Engineering Staff Knowledge and Performance

E4.1 Engineering Support Program (ESP) Review Board

a. Inspection Scope (37551)

During the inspection period, the inspectors reviewed a licensee initiative to improve the effectiveness of safety system performance and reliability through the use of ESP review boards. The inspectors attended a review board for the ice condenser system, reviewed standard agenda format and objectives for the review boards, and discussed the process with engineering management.

b. Observations and Findings

The ESP review board objectives were established, in part, to 1) provide constructive input to the system engineers for improving management in the areas of generation risk, 2) evaluate methods presented by the system engineer to improve system reliability, and 3) to assess the results of a structured generation risk review for the subject system. The licensee began these types of reviews in early 1998 and have accomplished a number of complete reviews since inception. In general, the ESP review board meets every six weeks to review an additional system with followup reviews scheduled on six month intervals. Methodology training was conducted in January 1998 for the system engineers to acquaint them with management's expectations of the review process.

On August 4, 1998, the inspectors attended an ESP review board for the ice condenser system. The ESP board was comprised of a multi-disciplined team from operations, maintenance, engineering and other personnel, including management. Prior to the meeting, the system engineer and other support personnel prepared an ice condenser system health report and a risk analysis report, which were reviewed by the ESP board participants prior to the meeting. During the meeting, the system engineer presented the performed reviews focusing on risk management and received candid feedback on both positive attributes as well as areas targeted for improvement. During this specific ESP board, the inspectors noted that the board encouraged increased walkdowns of the support systems, requested development of an action plan to review a long-term degraded component, and recommended several improvements in the maintenance training area. Throughout the meeting, the inspectors considered that the participants performed in-depth reviews of the subject system and asked challenging questions of the system engineer to facilitate future improvements in risk reduction and system oversight.

c. Conclusions

The overall implementation and conduct of the Engineering Support Program review board was detailed and probing, and provided initiatives to improve the overall reliability of the system and the oversight of the system engineering function. This engineering improvement process was considered a strength.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) Inspector Followup Item (IFI) 50-369,370/96-11-01: Actions to Address Motor Operated Valve (MOV) Weaknesses.

This followup item was opened pending completion of actions to resolve issues identified during an NRC inspection of the licensee's implementation of Generic Letter 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance." The issues and their proposed resolution actions were documented in McGuire PIP 0-M96-3542. The proposed actions were acceptable to the NRC. During the current inspection, NRC inspectors reviewed the status of PIP 0-M96-3542 and found that the resolution actions were reported to be complete. To verify completion, the inspectors reviewed associated specification and calculation changes, work orders (WOs) for hardware changes, and other licensee documents. These documents involved many improvements to hardware, analyses, and requirements. Overall, the inspectors found that the licensee had completed thorough and technically sound resolutions of the issues identified. All of the issues were considered sufficiently resolved for NRC closure, though weaknesses were noted in portions of the actions completed for three issues. The issues, resolution actions, documents reviewed by the inspectors, and the inspectors' findings are discussed in the following paragraphs. The weaknesses are described under the headings for Issue 5 (lack of data for Nitronic 60 body guide friction), Issue 12 (marginal thrust capability of valve 2RN0042), and Issue 13 (lack data on use of motor power monitor to assess packing loads).

Issue 1: Inspectors were concerned that the licensee only applied an 84 percent (1-sigma) statistical confidence level in calculating thrust requirements for low risk motor-operated gate valves. In addition, the inspectors were concerned that the thrust requirements contained no margin for aging/degradation. PIP 0-M96-3542 proposed the following corrective actions to resolve this issue:

- Revise Duke Power Specification DPS 1205.19-00-0002 to require use of a 95 percent (2-sigma) confidence level in place of 84 percent.

- Revise the motor-operated gate valve thrust calculations to apply a 95 percent confidence level.

- Include guidance in specification DPS 1205.19-00-0002 on consideration of potential motor-operated valve (MOV) aging/degradation effects.

- Review work documents for the Unit 1 outage to ensure they reflect the appropriate MOV setup requirements for the revised (95percent) confidence level.

The NRC inspectors verified completion of the above actions as follows:

- The inspectors reviewed DPS 1205.19-00-0002, "Guidelines for Performing Motor Operated Valve Reviews and Calculations," Revision 6, and verified that the 95 percent confidence level had been specified.

- The inspectors reviewed the following examples of calculations and Minor Modifications and verified that the 95 percent confidence level had been applied:

  For low margin valve 2CA0009 - Calculation MCC 1205.19-00-0016, "GL 89-10 Verification for MOV Group A Walworth 150 lb. Gate Valves," Revision 2; and Minor Modification 9891.

  For low margin valve 1NV0245 - Calculation MCC 1205.19-00-0049, "GL 89-10 Verification for MOV Group Q Walworth 3" 1500 lb. Gate Valves," Revision 1; and Minor Modification 9795.

  For low margin valve 1ND0001 - Calculation MCC 1205.19-00-0050, "GL 89-10 Verification for MOV Group R Walworth 14" 1500 lbs. Gate Valves," Revision 1; and Minor Modification 9887.

- The inspectors verified that DPS 1205.19-00-0002, Revision 6, now provided guidance for consideration of potential MOV aging and degradation effects. It specified that 5 percent margin should be added to account for degradation uncertainties, with adjustments to this value as test data was obtained. The inspectors also verified that this guidance was implemented in McGuire MOV Setup Calculation MCC 1205.19-00-0003, "Electric Motor Operator Sizing Guidelines per GL 89-10 for Gate Valves," Revision 5.

- Licensee personnel informed the inspectors that they had been unable to issue revised thrust requirements for the Unit 1 outage, as it had occurred only a month after NRC inspectors identified the confidence level issue. Instead, they determined where the old and new thrust requirements overlapped and requested the craft to set the valves for the region of overlapping requirements. The inspectors verified the sheets that had been prepared to depict the overlapping thrust requirement windows for two of the valves - 1NC0056 and 1NI0020.

The inspectors considered this issue closed.

<u>Issue 2</u>: Inspectors found that the licensee sometimes included multiple test data points from a given valve in the valve factor data analyzed from a group of valves. This had not significantly impacted the current analyses but might bias a future analysis. PIP 0-M96-3542 proposed to revise Duke Power Specification DPS-1205.19-00-0002, to require the number of data points per valve to be equalized to avoid biasing the group valve factor in favor of valves with more data points.

The NRC inspectors verified that the requirement to equalize the number of data points for analysis had been subsequently incorporated into DPS-1205.19-00-0002, Revision 6. The inspectors considered this issue closed.

<u>Issue 3</u>: Calculation DPC-1205.19-00-0002, "Evaluation of Rate-of-Loading Effects," Revision 0, evaluated the rate of loading data obtained in the licensee's MOV tests. At the time of the NRC inspection of the licensee's implementation of Generic Letter 89-10, this evaluation did not include the most current data, which was provided separately for NRC review. PIP 0-M96-3542 stated that DPC-1205.19-00-0002 would be updated to include the more recent test data.

The NRC inspectors reviewed DPC-1205.19-00-0002 and found that the revision sheet indicated that this calculation had been subsequently updated twice (revisions 1 and 2) to incorporate up-to-date data. The inspectors reviewed revision 2 and found the mean and standard deviation determined for McGuire's valves had been revised and were now consistent with values established during their previous inspection. The inspectors considered this issue closed.

<u>Issue 4</u>: Eleven valves with low (less than 0.50) available valve factors were identified as having marginal thrust capabilities for operation at design basis conditions. PIP 0-M96-3542 proposed to upgrade these valves at the next refueling outage to increase their thrust margins.

The NRC inspectors found that the licensee had increased the thrust margins for all of the eleven valves. This was accomplished primarily through mechanical upgrades, such as actuator replacements and torque switch setting increases. However, for several valves, the increased margins were based on actuator bench tests that demonstrated increased capabilities or on re-evaluations of the design basis differential pressures (DBDPs) that resulted in reduced thrust requirements. The inspectors verified the licensee's completion of these actions to increase valve thrust margins by reviewing the following sample of documents for the eleven valves:

1NC0031	Work Order (WO) 96083590 - replaced actuator and reset torque switch
1NC0033	WO 96065107 - replaced actuator and reset torque switch
1NC0035	WO 96083591 - reset torque switch
1ND0019	Calculation MCC-1223.11-00-0024, "Data Sheets for ND EMO Valves per GL 89-10," Revision 5 - re-evaluated DBDP and determined it was less than originally assumed
1NI0100	Calculation MCC-1205.19-00-0017, "GL 89-10 Verification for MOV Group B," Revision 2 - reduced thrust requirements based on determining the DBDP was less than originally assumed
1NV0244	WO 96042006 - bench tested actuator and reset torque switch
1NV0245	WO 96065098 - bench tested actuator and reset torque switch
2NC0031	WO 96100836 - replaced actuator and reset torque switch
2NC0033	WO 96100835 - replaced actuator and reset torque switch
2NC0035	WO 96100834 - replaced actuator and reset torque switch
2NV0095	WO 96098463 - replaced actuator and reset torque switch

The inspectors reviewed the current licensee spreadsheet calculation for the above valves and found that the available valve factors of all of the valves were now 0.55 or greater. Additionally, the valve thrust margins in the safety function direction exceeded 9 percent for all of the valves. The inspectors considered this issue closed.

Issue 5: The valve factor which the licensee used to calculate the thrust requirements for the six McGuire Power Operated Relief Valve Block Valves (Group K gate valves 1/2NC0031, NC0033, and NC0035) was based on test data obtained from similar valves at the Catawba plant. NRC inspectors questioned the applicability of this data, as it was obtained under pumped flow conditions and the McGuire valves function under blowdown flow. PIP 0-M96-3542 indicated that the licensee would obtain additional data to support the thrust requirements for these valves, such as through use of the Electric Power Research Institute (EPRI) Performance Prediction Methodology (PPM).

The NRC inspectors verified that the licensee had subsequently used the EPRI PPM to establish thrust requirements for these valves. The PPM input and results were documented and evaluated in Calculation MCC 1205.19-00-0035, "GL 89-10 Verification for MOV Group K Borg Warner 3" 1528 lb. Class Gate Valve," Revision 4. The calculation noted that the licensee's body guide material, Nitronic 60, differed from that tested in development of the PPM. A qualitative argument, based on similarity in hardness, was used to justify that Nitronic 60 was equivalent to the Stellite tested for the PPM. The inspectors accepted this justification but observed that the justification was weakened by the lack of quantitative test data comparing the materials. The inspectors considered this issue closed.

Issue 6: The licensee changed the stem friction coefficient used in MOV calculations from 0.15 to 0.20. MOV program documents required updating to incorporate this change. PIP 0-M96-3542 indicated that McGuire gate valve Calculation MCC 1205.19-00-0003, globe valve Calculation MCC 1205.19-00-0007, and Corporate Specification DPS-1205.19-00-0002 would be revised to incorporate the new 0.20 value.

The NRC inspectors reviewed the current revisions of the calculations and specification and verified that the 0.20 stem friction coefficient had been incorporated. The revisions reviewed were as follows:

- MCC 1205.19-00-0003, "Electric Motor Operated Valve Sizing Guidelines for Gate Valves," Revision 5
- MCC 1205.19-00-0007, "Electric Motor Operated Valve Sizing Guidelines per GL 89-10 for Globe Valves," Revision 4
- Specification DPS-1205.19-00-0002, "Guidelines for performing Motor Operated Valve Reviews and Calculations," Revision 6

The inspectors considered this issue closed.

Issue 7: A licensee analysis of stem friction coefficient data questioned the effectiveness of the licensee's lubrication preventive maintenance. PIP 0-M96-3542 indicated that the results of this analysis would be discussed with plant personnel to reinforce the importance of performing high quality stem lubrication.

The inspectors were informed that the lubrication analysis results and the importance of stem lubrication had been discussed with MOV maintenance crews. The inspectors verified that a list of attendees had been recorded in PIP 0-M96-3542. The inspectors considered this issue closed.

Issue 8: The licensee had dynamically tested one of McGuire's two non-Kerotest globe valves to establish thrust requirements for design basis operation. Thrust requirements for the other were calculated using a valve factor conservatively higher than obtained for the tested valve and values of other uncertainties based on an 84percent confidence level analysis. NRC inspectors expressed concern that this confidence level was too low. PIP 0-M96-3542 indicated that the licensee's thrust calculations would be revised to be more consistent with accepted deterministic methods. Specifically, the PIP stated that the uncertainties would be applied at a 95percent confidence level instead of the 84 percent level.

The NRC inspectors reviewed Calculation MCC 1205.19-00-0042, "GL 89-10 Verification for Non Kerotest Globe MOVs," Revision 1, and verified that the thrust requirement had been re-calculated applying 95percent confidence level uncertainty values in place of 84 percent. The inspectors considered this issue closed.

Issue 9: The valve factor used to calculate the thrust requirements for Group F gate valve 1CF0129 was considered somewhat weak, as it was based on the results of just two tests performed on valves at another plant. Further, the thrust capability of valve 1CF0129 only marginally exceeded the minimum requirement. PIP 0-M96-3542 indicated that the licensee would upgrade this MOV at the next refueling outage.

The NRC inspectors verified that the licensee had completed the upgrade by installing a bench tested replacement actuator on valve 1CF0129. They reviewed the record of the replacement which was documented on WO 97003540. The licensee's spreadsheet calculation indicated that the current thrust margin for this valve was over 12 percent. The inspectors considered this issue closed.

Issue 10: Group B consisted of 24 Aloyco split-wedge gate valves of different sizes. Four 12-inch valves in this group had marginal capabilities to operate at design basis conditions and none of these valves had been dynamically tested. These were containment spray valves 1/2NS0003 and NS0020. PIP 0-M96-3542 proposed to initiate work requests to improve the margin for these valves and to obtain additional test data to support the group valve factor.

The inspectors found that the action taken by the licensee for these valves differed from that originally proposed but was acceptable. The design basis differential pressure for the valves had been re-evaluated and found too high, such that the capability margin was much larger than originally determined. The inspectors reviewed and verified the related changes to the respective design basis differential pressure and thrust requirements calculations:

- MCC 1223.13-00-0015, "Maximum Expected dPs of NS EMO Valves - Reference GL 89-10," Revision 4
- MCC 1205.19-00-0017, "GL 89-10 Verification for MOV Group B Aloyco Split Wedge 6", 8", 12"," Revision 2

The differential pressure was reduced from 69 to 23 pounds per square inch, resulting in a capability margin of over 100 percent for each of the four valves. The inspectors considered this issue closed.

Issue 11: The results of a licensee test program indicated that the vendor (Kerotest) method for predicting thrust requirements for the 2-inch soft-seated Kerotest globe valves was nonconservative for certain service applications. PIP 0-M96-3542 indicated that corporate calculation DPC-1205.01-00-0001 would be revised to consider service application and addition of margin when using the vendor method.

The inspectors reviewed DPC-1205.01-00-0001, "Evaluation of Flow Loop Tests of Kerotest Valves," Revision 2, and found that it stated that the vendor thrust prediction method was non-conservative and that margin should be added when it was used. No exception was permitted based on service application. The inspectors noted that this calculation change was somewhat weak in that definitive margins were not given. Licensee personnel responded that McGuire did not use the vendor method to predict thrust. Instead, the standard industry equation was applied, which predicted thrust conservatively for all McGuire applications. As an example, the inspectors examined the thrust determination for

Kerotest globe valve 1KC0429 from McGuire Calculation MCC 1205.19-00-0007, "Electric Motor Operated Valve Sizing Guidelines per GL 89-10 for Globe Valves," Revision 4, and confirmed that the standard industry equation had been used. The inspectors considered this issue closed.

Issue 12: Weaknesses were identified in the test data which the licensee had evaluated to establish torque requirements for three groups of butterfly valves:

- Group E consisted of twelve (six per unit) 10-inch, class 150, model NMK 11, Henry Pratt butterfly valves. These valves were addressed by validation Calculation MCC-1205.19-00-0030, Rev. 0. The data used to establish settings and capabilities for these valves was considered weak because it was from static and dynamic tests performed on much larger (16-inch) valves. Additionally, relying on this data, the calculated capabilities of several of the valves only marginally exceeded the design basis requirements (by 1 percent or less).

- Group I consisted of four (two per unit) 6-inch, class 150, model 7620, Fisher Controls butterfly valves. The test data used to establish the settings and capabilities of these valves was considered weak because it was not quantifiable by standard evaluation methods and the dynamic testing had been performed at only about 60 percent of design basis differential pressure. The calculation employed what was referred to as a "non-typical validation" approach in assuring the capabilities of these valves.

- Group K consisted of four (two per unit) 8-inch, class 150, model NMK11, Henry Pratt butterfly valves. The inspectors found the data which the licensee had used to establish the settings and capabilities of these valves was weak because it was based on tests performed on tests of much larger valves (16- and 20-inch). The licensee had statically and dynamically tested the group K valves but had determined that the test results could not be relied upon for quantitative evaluations. Further, the licensee did not qualitatively demonstrate the capabilities of the valves through the group K valve dynamic tests, as they were performed at only about 60 percent of design basis differential pressure.

PIP 0-M96-3542 indicated the above weaknesses would be addressed by performing additional dynamic testing on valves from all three groups. Additionally, PIP 0-M96-3542 stated that the torque switches of the marginal Group E valves would be raised to assure the valves would perform their design basis functions.

The inspectors reviewed documentation of the tests and evaluations which the licensee subsequently performed on the above groups of butterfly valves and verified that the issue of weak test data was adequately addressed. Their findings were as follows:

- The inspectors found that the licensee had performed dynamic torque tests on 4 of the 12 Group E butterfly valves. The results of these tests were reported and evaluated in validation calculation MCC 1205.19-00-0030, "GL 89-10 Design Basis Verification for 10" Class 150 Henry Pratt Electric Motor Operated Butterfly Valves," Revision 1. This calculation demonstrated that the torque requirements previously determined and applied to these valves, based on the licensee's calculation method and motor power monitor test results, had been conservative. Vendor torque predictions, which did not consider any possible age-related degradation of the valves, were non-conservative.

The inspectors noted some continuing weakness in the licensee's evaluation, as most of the data evaluated was from tests performed at about 40 percent of the design basis differential pressure. This weakness was countered by the high calculated torque capability margins which most of the valves had at their current torque switch settings. Nine of the 12 valves in the group had margins of 50 percent or more and only 1 had a margin of less than 20 percent. This valve was 2RN0042, which had about a 9 percent margin (including 6 percent for aging and degradation). Valve 2RN0042 was classified as a low risk valve and a work order (WO 97054678) had been identified to raise its torque switch setting to increase the margin.

- The inspectors found that the licensee had performed dynamic torque tests on all four of the Group I butterfly valves. The results of these tests were reported and evaluated in validation calculation MCC 1205.19-00-0034, "GL 89-10 Design Basis Verification for 6" Class 150 Fisher Controls Electric Motor Operated Butterfly Valves," Revision 1. This calculation demonstrated that the torque requirements previously determined and applied to these valves, based on the licensee's calculation method and motor power monitor test results, had been conservative. All four valves had capability margins of about 50 percent.

- The inspectors found that the licensee had performed dynamic torque tests on all four of the Group K butterfly valves, though satisfactory data was not obtained in one case. The results of these tests were reported and evaluated in validation calculation MCC 1205.19-00-0038, "GL 89-10 Design Basis Verification for 8" Class 150 Henry Pratt Symmetric Electric Motor Operated Butterfly Valves," Revision 1. This calculation demonstrated that the torque requirements previously determined and applied to these valves, based on the licensee's calculation method and motor power monitor test results, had been conservative. Additionally, the vendor calculation was conservative for these valves. All four valves had capability margins of about 100 percent or more.

<u>Issue 13:</u> Inspectors were concerned that the licensee's post-maintenance test (PMT) program did not specify a thrust measurement to assure that packing adjustment or repacking would not result in an excessive load. PIP 0-M96-3542 indicated the licensee would:

- Update the PMT requirement documents, giving details of the PMT to be performed.

- Provide justification (e.g., test results) to support performance of packing adjustment or repacking a valve without a diagnostic test. (Later negated based on cost, as described below.)

The inspectors found that the licensee now relied on a "PMT Guidance Document," Revision 2, computer listing for PMT requirements. This listing required an instrumented test following packing adjustment or replacement, with engineering contacted for specific requirements. Licensee engineering personnel informed the inspectors that their normal practice was to perform a diagnostic thrust test. However, as an alternative instrumented test, a motor power monitor (MPM) test might be performed in place of diagnostic testing when this could be justified by the engineer based on a very large margin (greater than 50 percent). PIP 0-M96-3542 stated that McGuire valve engineering had determined that it was cost prohibitive to collect thrust data specifically to justify packing adjustment or replacement without a diagnostic test. It reported that valve engineering would continue to collect thrust data as part of the McGuire surveillance program and would modify their PMT, if this data supported a change. The inspectors found the licensee's PMT program improved but still weak with regard to data justifying use of MPM. The actions completed by the licensee were considered adequate. This IFI is closed.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Tour of Radiological Protected Areas

a. Inspection Scope (86750)

The inspectors reviewed implementation of selected elements of the licensee's radiation protection program as required by 10 CFR Parts 20.1902 and 1904. The review included observation of radiological protection activities for control of radioactive material, including postings and labeling, and radioactive waste processing.

b. Observations and Findings

The inspectors reviewed survey data of radioactive material storage areas. Observations of independent radiation and contamination survey results determined the licensee was effectively controlling and storing radioactive material and all material observed was appropriately labeled as required by 10 CFR Part 20.1904. All areas observed were appropriately posted to specify the radiological conditions. The inspectors determined the licensee was processing radioactive waste to maintain exposures As Low As Reasonably Achievable (ALARA) and to minimize quantities of radioactive waste stored on site.

c. Conclusions

The inspectors determined the licensee was effectively maintaining controls for radioactive material storage and radioactive waste processing.

R1.2 Water Chemistry Controls

a. Inspection Scope (84750)

The inspectors reviewed implementation of selected elements of the licensee's water chemistry control program for monitoring primary and secondary water quality as described in TS, the Station Chemistry Manual, and the Updated Final Safety Analysis Report (UFSAR). The review included examination of program guidance and implementing procedures and analytical results for selected chemistry parameters, and observation of chemistry technicians collecting water samples.

b. Observations and Findings

The inspectors reviewed selected analytical results recorded for Units 1 and 2 reactor coolant samples taken between January 1, 1998, and August 5, 1998, and secondary samples taken between January 1, 1998, and August 3, 1998. The parameters reviewed for primary chemistry included dissolved oxygen, chloride, pH, and fluoride. The parameters reviewed for secondary chemistry included hydrazine, iron, and chloride. Primary parameters reviewed were maintained well within the relevant TS limits for power operations. Secondary parameters reviewed were maintained within the limits of the Station Chemistry Manual.

The inspectors observed sample collections from the following Unit 2 plant locations: 1) spent fuel pool, 2) letdown heat exchanger outlet, 3) mixed bed demineralizer outlet, and 4) reactor coolant hotleg number 1. The inspectors verified that the sample collection was performed as required by licensee chemistry sampling procedure, OP/2/B/6200/011, Revision 19, Unit 2 Reactor Coolant System Sampling.

c. Conclusions

The inspectors concluded that the licensee's water chemistry control program for monitoring primary and secondary water quality had been effectively implemented in accordance with TS requirements and the Station Chemistry Manual for water chemistry. The inspectors also concluded that the collection of the samples was performed in accordance with the licensee's chemistry sampling procedure.

R2 Status of Radiation Protection (RP) Facilities and Equipment

R2.1 Process and Effluent Radiation Monitors

a. Inspection Scope (84750)

The inspectors reviewed selected licensee procedures and records for required surveillance on process and effluent radiation monitors. The inspectors also reviewed licensee records regarding radiation monitor availability.

b. Observations and Findings

During tours of the auxiliary building and radwaste building, and interim radwaste building, the inspectors observed the physical operation of process radiation effluent monitors in service. The inspectors also toured the control rooms and observed the status of radiation monitoring equipment. The inspectors reviewed selected radiation and process monitor surveillance procedures and records for performance of channel checks, source checks, channel calibrations, and channel operational tests. The inspectors determined the licensee was performing checks described in TS and Chapter 16 of the UFSAR. For the previous 12 month period, monitors required by TS were available 96.15 percent of the time and monitors not required by TS were available an average of 99.08 percent. The inspectors noted the lowest availability for a monitor described in Chapter 16 of the UFSAR was 39.57 percent. This monitor was the Unit 2 turbine building sump monitor (2EMF31). Prior to this inspection, the licensee found the detector did not respond properly while performing channel calibration. Counts were very low when the source was connected to the detector. The licensee initiated PIP 2-M98-0940 to address the root cause of the detector failure. Based on a review of source check data, the licensee determined the monitor was malfunctioning from August 11, 1997, until March 16, 1998, when the problem was discovered. The inspectors discussed this licensee identified problem with licensee management. The licensee determined there was no unaccounted for releases of radioactive material during this period. Therefore, this detector failure was not reportable to the NRC. The inspectors verified the licensee had initiated planned corrective actions regarding this issue.

The inspectors observed environmental samplers at two air sampling stations and two liquid sampling stations and discussed sampling procedures with laboratory personnel. The inspectors determined that the sampling equipment was calibrated and functional at the time of inspection. The inspectors also verified locations were consistent with their descriptions in the UFSAR and that the samples performed were in accordance with procedure, Operational Radiological Environmental Sample Collection Program For McGuire Nuclear Station, Revision 8. The licensee did identify two sampling deviations in 1998. One deviation was the result of a power line being down causing a loss of power to a surface water sampler and the other deviation was a missing environmental thermoluminescent dosimeter (TLD). Both of these deviations were corrected in a timely manner.

c. Conclusions

The inspectors concluded radiation and process effluent and environmental monitors were being maintained in an operational condition to comply with TS requirements and UFSAR commitments.

R2.2 Meteorological Monitoring Equipment

a. Inspection Scope (84750)

The inspectors reviewed licensee procedures to verify licensee compliance with Section 2.3 of the UFSAR which described the operational and surveillance requirements for the meteorological monitoring instrumentation.

b. Observations and Findings

The inspectors toured the control room and determined the meteorological instrumentation was operable and that data for wind speed, wind direction, air temperature, and precipitation were being collected as described in the UFSAR. Based on a review of records, the licensee had maintained a high level of operability for meteorology equipment during 1998. Wind speed and wind direction instruments at ten and forty-three meters were operable approximately 97.9 percent, air temperature approximately 97.9 percent and precipitation 98.1 percent.

At the time of the inspection, the licensee was constructing a new meteorological tower which would include sampling stations at ten and sixty meters. This tower would replace the sampling stations at the currently existing ten and forty-three meter towers. A TS change was requested by the licensee to relocate the meteorological equipment. A TS amendment was issued by the NRC on July 30, 1998, to allow for the relocation of the meteorological tower. The meteorological tower was being relocated to facilitate the use of the current location as a construction site.

c. Conclusions

Based on the above reviews and observations, it was concluded that the meteorological instrumentation had been adequately maintained and that the meteorological monitoring program had been effectively implemented.

R5 Staff Training and Qualification in Radiation Protection and Chemistry

R5.1 Staff Training and Qualification Review

a. Inspection Scope (84750)

The inspectors evaluated the qualifications of the chemistry management staff to determine if all qualification requirements were met in accordance with TS 6.3.1. Also evaluated was the training for chemistry technicians to determine if they met the training requirements in TS 6.4.

b. Observations and Findings

The inspectors observed through a review of qualification records that the chemistry management staff met the qualification requirements in TS 6.3.1. The inspectors also determined through a review of the training requirements and training records that the chemistry technicians had been properly trained to perform their assigned duties as committed to in the licensee's TS.

c. Conclusions

The inspectors concluded that the chemistry management staff met the qualification requirements of technical specification 6.3.1. Also, the chemistry technicians had been properly trained for the duties they had been assigned as required by TS 6.4.

V. Management Meetings

X1 Exit Meeting Summary

The resident inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on August 28, 1998. The licensee acknowledged the findings presented. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

Barron, B., Vice President, McGuire Nuclear Station
Bhatnagar, A., Superintendent, Plant Operations
Boyle, J., Civil/Electrical/Nuclear Systems Engineering
Byrum, W., Manager, Radiation Protection
Cash, M., Manager, Regulatory Compliance
Dolan, B., Manager, Safety Assurance
Evans W., Security Manager
Geddie, E., Manager, McGuire Nuclear Station
Peele, J., Manager, Engineering
Loucks, L, Chemistry Manager
Thomas, K., Superintendent, Work Control
Travis, B., Manager, Mechanical Systems Engineering

INSPECTION PROCEDURES USED

IP 71707:	Conduct of Operations
IP 62707:	Maintenance Observations
IP 61726:	Surveillance Observations
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 37551:	Onsite Engineering
IP 71750:	Plant Support
IP 73756:	Inservice Testing of Pumps and Valves
IP 84750:	Radioactive Waste Treatment, And Effluent And Environmental Monitoring
IP 86750:	Solid Radioactive Waste Management and Transportation Of Radioactive Materials
IP 90712:	LER Review
IP 92903:	Follow-up-Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-369,370/98-08-01	URI	Inoperable Auxiliary Building Ventilation Systems (Section O2.2)
50-370/98-08-02	VIO	Failure to Adequately Vent ECCS Piping - Two Examples (Section E2.1)

Closed

50-369/98-01	LER	Inadvertent Removal of a FWST Channel From Tripped Condition and a CPCS From Start Permissive Condition (Section O8.1)
50-369,370/96-11-01	IFI	Actions to Address MOV Weaknesses (Section E8.1)

Discussed

50-369/98-05	LER	Two Auxiliary Building Filtered Ventilation Exhaust Systems Were Inoperable Longer than the Action Times Allowed by TS 3.7.7. (Section 02.2)
50-369/98-06	LER	Non-compliance With Ice Condenser Technical Specification 4.6.5.1.b.3 Requirements (Section 02.1)

LIST OF ACRONYMS USED

ALARA - As Low As Reasonably Achievable
AFW - Auxiliary Feedwater
ASME - American Society of Mechanical Engineers
ANSI - American National Standards Institute
CCP - Centrifugal Charging Pump
CFR - Code of Federal Regulations
CPCS - Containment Pressure Control System
CR - Control Room
DBDP - Design Basis Differential Pressures
dP - Differential Pressure
DPS - Duke Power Specification
ECCS - Emergency Core Cooling System
EDG - Emergency Diesel Generator
ENS - Emergency Notification System
EOC - End-of-Cycle
EPRI - Electric Power Research Institute
ESP - Engineering Support Program
ESF - Engineered Safety Feature
F - Fahrenheit
FME - Foreign Material Exclusion
FWST - Refueling Water Storage Tank
GL - Generic Letter
IFI - Inspector Followup Item
IN - Information Notice
IR - Inspection Report
IST - Inservice Testing
LER - Licensee Event Report
LSE - Less Significant Event
LOCA - Loss of Coolant Accident
MCC - McGuire Certified Calculation
MGMM - McGuire Minor Modification
MOV - Motor-Operated Valve
MPM - Motor Power Monitor
MSE - More Significant Event
NCV - Non-Cited Violation
NPF - Nuclear Power Facility
NRC - Nuclear Regulatory Commission
NRR - NRC Office of Nuclear Reactor Regulation

NSD	-	Nuclear Site Directive
OM	-	Operations and Maintenance
OMP	-	Operations Management Procedures
PDR	-	Public Document Room
PIP	-	Problem Investigation Process
PM	-	Preventive Maintenance
PMT	-	Post-Maintenance Testing
PPM	-	Performance Prediction Methodology
psig	-	pounds per square inch gage
PT	-	Periodic Testing
R&R	-	Removal and Restoration
RCA	-	Radiologically Controlled Area
RCS	-	Reactor Coolant System
RHR	-	Residual Heat Removal
RP	-	Radiation Protection
RWP	-	Radiation Work Permit
SBLOCA	-	Small Break Loss of Coolant Accident
SFP	-	Spent Fuel Pool
SGRP	-	Steam Generator Replacement Project
SR	-	Surveillance Requirement
Tavg	-	Average Temperature
TDAFW	-	Turbine Driven Auxiliary Feed Water
TLD	-	Thermoluminescent Dosimeter
TM	-	Temporary Modification
Tref	-	Reference Temperature
TS	-	Technical Specifications
TSSR	-	Technical Specification Surveillance Requirement
UFSAR	-	Updated Final Safety Analysis
URI	-	Unresolved Item
USQ	-	Unreviewed Safety Question
UT	-	Ultrasonic
V	-	Volt
VIO	-	Violation
WO	-	Work Order
ZPPT	-	Zero Power Physics Testing