U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-263/89027(DRP)

Docket No. 50-263 License No. DPR-22

Licensee: Northern States Power Company
414 Nicollet Mall
Minneapolis, MN 55401

Facility Name: Monticello Nuclear Generating Station

Inspection At: Monticello Site, Monticello, Minnesota

Inspection Conducted: October 15 through November 25, 1989

Inspectors: J. E. Hard
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Reactor Projects Section 2B

12/12/89
Date

Inspection Summary

Inspection on October 15 - November 25, 1989 (Report No. 50-263/89027(DRP)
Areas Inspected: A routine, unannounced inspection by the resident inspectors of previous inspection items; operational safety verification; maintenance; surveillance; and onsite followup of operational events. Planning and work performance related to the outage was also inspected.
Results: The licensee's planned 79 day refueling outage was extended to 83 days with reactor startup commencing on November 7 and the Unit being placed on the grid on November 9 following turbine generator testing. The resident inspectors observed several activities related to the startup including the integrated ECCS test, the containment integrated leak rate test, and startup surveillance activities. Secondary Containment integrity was successfully demonstrated on October 31 when the Standby Gas Treatment System (SGTS) was able to draw greater than the required 0.25 inches water vacuum with the plenum fans secured. Secondary Containment was declared operable on November 4 following the results of Design Basis Accident offsite dose calculations. A reactor scram occurred on November 15 during a routine surveillance of the Average Power Range Monitor Recirculation Flow Bias Test. The scram was due to an electrical spike from a pressure sensor while the Reactor Protection System was in a half scram condition per the surveillance procedure.

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DETAILS

1. Persons Contacted

J. J. Howard, President and Chief Executive Officer
C. E. Larson, Vice President, Nuclear Generation
*D. D. Antony, Plant Manager
M. H. Clarity, Assistant to the Plant Manager
B. D. Day, General Superintendent, Engineering & Radiation Protection
D. E. Nevinski, General Superintendent, Operations
R. L. Scheinost, General Superintendent, Quality, Security and Administration
L. L. Nolan, Superintendent, Nuclear Technical Services
S. A. Engelke, Superintendent, Nuclear Technical Services
S. J. Hammer, Superintendent, Operations Engineering
G. T. Bart, Quality Supervisor, Corporate Quality Assurance
G. L. Hudson, Superintendent, Security
P. A. Johnson, Manager, Monticello Nuclear Projects Department
J. D. Kuhn, Quality Assurance Specialist, Corporate Quality Assurance

The inspector also contacted other licensee employees including members of the technical and engineering staffs, and reactor and auxiliary operators.

*Denotes the licensee representatives attending the resident inspectors' exit meeting.

2. Licensee Action on Previous Inspection Findings (92701, 92702)

(Closed) Violation (263/84026-02(DRS)): Inadequate Type A test procedure in that it did not incorporate the required type of data reduction method for the performance of a short duration test (<24HR).

The inspector reviewed Test 0136, Revision 1, "Integrated Primary Containment Leak Rate Test," and determined that it contained the required controls for the performance of Type A and verification tests in accordance with BN-TOP-1, Revision 1, (<24HR) and mass point (≥24HR) data reduction method. This item is considered closed.

(Closed) Violation (263/88009-01(DRP)): Failure to Verify Proper Emergency Filtration Train (EFT) Loads onto Emergency Diesel Generator (EDG).

The inspector verified that the following corrective actions had been achieved by the licensee. Additional guidance has been provided in the Modification Procedure to ensure all affected Technical Specifications (TS) are reviewed when identifying surveillance requirements. All technical staff has been given training and additional guidance on identifying all TS requirements during the modification process. The sequencing of the EFT loads was verified during the ECCS Automatic Initiation Test Including Loss of Auxiliary Power, No. 0189-3, Revision 13

(Closed) Open Item (263/88010-03(DRP)): High Vibration On SGTS Motor.

The licensee rebalanced the SGTS motor to eliminate the high vibration readings.

3. Operational Safety Verification (71707)

a. Routine Inspection

The inspector observed control room operations, reviewed applicable logs and conducted discussions with control room operators during the inspection period. The inspector reviewed the use of hold and secure cards for the control of systems and electrical lineups. Tours of the radwaste building, reactor building, intake structure, turbine building, and areas where there was heavy activity related to the outage modifications were conducted to observe plant equipment conditions, including potential fire hazards, fluid leaks, and work practices.

These reviews and observations were conducted to verify that facility operations were in conformance with the requirements established under technical specifications, the Code of Federal Regulations, and the licensee's administrative procedures.

b. Transformer Fire

At 8:45 a.m. on November 5, 1989, Transformer XL116 was found to be smoking. This unit supplies power to the plant chemistry lab. The plant fire brigade was promptly mobilized, sealed off the smoky area, ran temporary ventilation to the outside, and monitored the smoking unit while efforts were being made to find the key necessary to open the cabinet to disconnect power from the unit. Other than a significant delay (several minutes) in finding the key for the 480V cabinet which powers XL116, the response of the plant forces to the emergency was excellent. The licensee has committed to a simpler key system for plant lighting cabinets. All plant actions with respect to this emergency were observed by the resident inspection staff.

c. Reactor Scram

A reactor scram occurred from 100 percent power on November 15. The scram occurred while conducting a surveillance on the Average Power Range Monitor Recirculation Flow Bias Test. This surveillance requires that the Reactor Protection System (RPS) be placed in a half scram condition while performing the trip setpoint calibration. The half scram was on RPS channel A. The I&C technicians had finished their work and were preparing to notify the control room when the B protection channel de-energized causing the scram. A review of the computer point data indicated that a high pressure signal had been generated from a pressure sensor causing the full scram logic to be fulfilled. The resident inspector entered the control room approximately 30 seconds following the scram and observed the recovery actions being taken to ensure that a safe shutdown had been achieved.

Investigation of the cause of the event indicated that the signal generated by the pressure switch was most likely an electrical signal spike. Evidence of this was determined by comparing the computer points from the original plant computer, GEPAC 4020, and its replacement VAX. The GEPAC receives instrumentation signals and holds the incoming signal for 132 ms. The VAX samples all inputs at 2 ms intervals. The GEPAC picked up the pressure signal spike and the VAX did not leading to the conclusion that the signal lasted for less than 2 ms. If the licensee had removed the GEPAC from service as it eventually plans to do, it would not have been able to determine the cause of the scram. The licensee intends to increase the data sampling frequency to 1 ms.

Followup actions included investigations as to whether the pressure switch had been inadvertently bumped; the recalibration of all four pressure switches and the replacement of the suspect pressure switch; and inspection of all pressure switch wiring for loose terminations. The reason for the pressure trip signal could not be determined. The resident inspectors attended the Operations Committee meeting for the restart of the reactor, observed the above followup actions, and monitored the restart of the reactor which commenced that evening.

d. <u>As Low As Reasonably Achievable (ALARA) Review</u>

The inspectors reviewed the personnel exposure and contamination data for the work performed during the outage to assess whether the licensee had made any progress as compared to previous outages. In addition, further efforts toward improved ALARA that had been implemented during the outage were reviewed.

The actual outage lasted 83 days during which outage personnel acquired 422 man rem of whole body exposure and 350 personnel contaminations. The ALARA plan had estimated 402 man rem for the outage.

Efforts to improve ALARA included the shielding and chemical decontamination of the recirculation piping system, extensive shielding of the RHR A shutdown cooling loop around the pumps, and the removal of a large section of the reactor water cleanup system piping. The estimated net savings as a result of these actions was between 600 to 700 man rem.

Comparisons to previous outages indicated improvements. In 1986 there were 462 man rem for a 73 day outage. In 1987 there were 397 man rem for a 57 day outage. The 1989 outage, which included extensive work inside the condenser shell for the replacement of feedwater heaters as well as extensive ISI on the reactor vessel and many areas inside the drywell, yielded a dose per day total of 5.1 man rem. This compares favorably to 6.3 man rem per day for the 1986 outage and 7.0 man rem per day for the 1987 outage.

Of the 350 personnel contaminations during the outage, 22 had a calculated skin exposure of more than 100 millirem with the highest being 2272 millirem. The daily contamination rate dropped throughout the outage through the implementation of added manpower, better equipment/material control, and extensive steam cleaning. Of significant note in the personnel contamination area is the installation of new exit portal monitors. These exit portal monitors were installed prior to the start of the outage and were set to alarm at 4 nanocuries vice the limit of 40 nanocuries for the previous outages. Even with this more sensitive detection limit, the rate of contaminations dropped to one contamination for every 392 entries vice one for every 250 in 1987.

Recent efforts being taken to further reduce exposure for future outages include continued chemical decontamination of the recirculation system piping, the installation of a Zinc Injection System, and a reduction of the amount of cobalt-bearing material in contact with the reactor coolant. It is estimated that the decontamination of the recirculation system piping saved 479 man rem. Zinc injection has been initiated for the start of the operating cycle to reduce the deposition of cobalt-60 in the reactor coolant system piping and equipment. Nine cobalt bearing control blades were replaced during the outage to reduce one source of cobalt-60.

e. Fuel Reliability and Offgas

The inspectors reviewed the licensee's measurements of its Fuel Reliability Indicator (FRI). The licensee uses the FRI calculation as specified by INPO and measures the steady state release rates for Xe-133, Xe-135, and Xe-138 in the offgas system. During the previous cycle 13 the FRI ranged between 2,000 and 3,000 microcuries/sec. During the present cycle 14 following three weeks of full power operation, the FRI has been substantially reduced to between 200 and 300 microcuries/sec.

The plant has also experienced a noticeable decrease in its steady state offgas activity. The activity is one half of what it was for the previous cycle. This is due in part to fuel sipping performed on all of the fuel from the previous cycle that was placed back into the core for the present cycle. The fuel sipping indicated that one fuel bundle demonstrated evidence of leaks. The licensee replaced that bundle and its three symmetrical partners. The fuel that was offloaded and not returned to the core has not yet been tested for leaks, so it is not known if the removal of this fuel has contributed substantially to this reduction or not. The licensee intends to perform fuel sipping on this fuel during the next year.

f. Secondary Containment Integrity

Secondary Containment integrity was successfully demonstrated on October 31 when the SGTS was able to draw greater than the required 0.25 inches water vacuum with the plenum fans secured. Secondary containment was declared operable on November 5 following the results of Design Basis Accident offsite dose calculations. (See paragraph 11.d. of this report).

g. Check Valve Review Program (73756)

An inspector reviewed selected areas of the Licensee's Check Valve Review Program, Revision 0. The areas reviewed conformed to the intent of the EPRI Report NP-5479, Application Guidelines for Check Valves in Nuclear Power Plants. One objective of this report was to provide the utilities with application guidelines for developing a program to respond to the INPO SOER 86-03, Check Valve Failures or Degradation.

INPO SOER 86-03 lists a number of check valve failures at power plants and identifies the causes to which these failures were attributed. The chief causes were indicated to be the misapplication of valves and inadequate preventive maintenance. Misapplication of valves included such errors as using an improper size valve, specifying the wrong type of valve, and placing the valve too close to an upstream pump, valve, elbow, or tee. In most cases the effect of improper valve location or improper valve size is to generate flow conditions which cause the disk to flutter. Disk flutter causes excessive wear on the disk and/or disk bearing contact surfaces. The bearing wear, in turn, can result in two additional problems: valve leakage and a failure to close.

The licensee's program contains considerable information about the plant's check valves. Detailed data sheets were provided for each valve in the program. Each sheet included a summary in which the potential problems and the features of each valve are identified, along with an analysis of the inspection technique and schedule. Justification for the position taken in the analysis was also given.

The administrative execution of the program conforms to the INPO guidelines. Each valve data sheet includes details such as valve orientation; flow; temperature; pressure; distance to the upstream valve, elbow or tee; the minimum flow velocity for the full lift of the disk; and the actual flow velocity. In addition, the history of each valve is provided, along with the history of any valves that preceded it in the given positions and functions. The sheet contains essentially everything that would be useful in analyzing the proper application of a valve. The inspector's review of the licensee's check valve program indicates that it is satisfactory.

h. Response to IEN 89-057

IEN 89-057, Unqualified Electrical Splices in Vendor-Supplied Environmentally Qualified (EQ) Equipment alerted licensees to a potential problem. The licensee's review of past events showed that the use of wire nut splices has been common in both safety and non-safety configurations. As a result of this, the licensee prepared a Justification for Continued Operation in 1987 to conditionally qualify the wire nut splices. In the past, wire nut splices were replaced as they were found in safety systems. Inspections have been completed to locate and replace wire nut splices in the SGTS and High Pressure Coolant Injection (HPCI) system.

A walkdown of instrument racks revealed that the following instruments located in the reactor building had wire nut splices in a condulet located between the instrument and its local rack-mounted junction box:

- Static-O-Ring pressure switches in the RHR system;
- Barton dP switches in the HPCI system;
- Barton pressure switch for the Core Spray valve open permissive.

Approximately 50 wire nuts were found in these instrumentation racks. Walkdowns performed revealed no wire nuts in use on specific safety-related EQ equipment in the plant. Likewise, no wire nuts were found to be in use in the Drywell on safety-related systems.

No violations or deviations were identified.

4. Verification of Containment Integrity (61715)

a. Procedure Review

The regional based inspector reviewed Test Procedure 0136, Revision 7, "Integrated Primary Containment Leak Rate Test" relative to the requirements of 10 CFR Part 50, Appendix J, ANSI N45.4-1972, and the TS. The review also included the proposed valve lineups for selected penetrations (X-217, X-221 and X-222 HPCI Exhaust; X-212, X-219 and X-223 Reactor Core Isolation Cooling (RCIC) Exhaust; X-21 and X-22 Instrument and Service Air; X-9B Loop A Feedwater; and X-9A Loop B Feedwater). All inspector's comments were satisfactorily resolved. The licensee understood that in order to use the TS value of La as the acceptance criteria for the containment "as found" leakage rate a specific exemption from the regulation value of 0.75 La was required.

b. Clarifications of Appendix J Requirements

To ensure the licensee's understanding of Appendix J requirements, a regional inspector discussed with the licensee, the following clarifications:

(1) The Type A test length must be 24 hours or longer to use the mass point method of data reduction. If tests of less than

24 hours are planned, the Bechtel Topical Report, BN-TOP-1, must be followed in its entirety, except for any section which conflicts with Appendix J or TS requirements. For either methodology, the acceptance criterion is that the measured leakage at the 95 upper confidence limit must be less than 75% of the maximum allowable leak rate for the pressure at which the test was performed.

(2) Periodic Type A, B, and C tests must include as-found results as well as as-left results. If Type B and C tests are conducted prior to a Type A test, the As-found Condition of the Containment must be calculated by adding any improvements in leakage rates, which are the result of repairs and adjustments (R/A), to the Type A test results using the "minimum pathway leakage" methodology. This method requires that:

(a) In the case where individual leak rates are assigned to two valves in series (both before and after R/A), the penetration through-leakages would simply be the smaller of the two valves' leakage rates.

(b) In the case where a leak rate is obtained by pressurizing between two isolation valves, and the individual valve's leak rates are not quantified, the as-found and the as-left penetration through-leakage for each valve would be 50% of the measured leak rate, if both valves are repaired.

(c) In the case where a leak rate is obtained by pressurizing between two isolation valves, and only one valve is repaired, the as-found penetration leak rate would conservatively be the final measured leak rate, and the as-left penetration through-leak rate would be zero. (This assumes the repaired valve leaks zero.)

(3) Penetrations which are required to be Type C tested, as described in the FSAR, SER, or TS must be vented inside and outside the containment during the Containment Integrated Leak Rate Test (CILRT). All vented penetrations must be drained of water inside the containment and between the penetration valves to ensure exposure of the containment isolation valves to containment air test pressure. The degree of draining of vented penetrations outside of containment is controlled by the requirement that the valves by subjected to the post-accident differential-pressure, or proof that the system was built to stringent quality assurance standards comparable to those required for a seismic system.

(4) Whenever penetration configurations during a CILRT deviate from the ideal, the results of the LLRT for penetrations must be added as a penalty to the CILRT results at the 95% upper confidence level. This penetration leakage penalty is determined using the "minimum pathway leakage" methodology. This methodology

is defined as the minimum leakage value that can be quantified through a penetration leakage path (e.g. the smallest leakage through two valves in series). This assumes no single active failure of redundant leakage. Additionally, any increase in containment sump, fuel pool, reactor water, or suppression pool level during the course of the CILRT, must be taken as a penalty to the CILRT results. If penalties exist they must be added (SUBTRACTION IS NEVER PERMITTED) to the upper confidence level of the CILRT results.

(5) The start of the CILRT must be noted in the test log at the time the licensee determines that the containment stabilization has been satisfactorily completed. Reinitializing a test in progress must be "forward looking," that is, the new start time must be that time at which the decision to restart is made. This also implies that the licensee has determined that the test has failed, and has enough data to quantify the leakage rate. Any deviation from these positions should be discussed, and documented, with the NRC CILRT Specialist Inspector as they occur to avoid later invalidation of the test results. Examples of acceptable deviations of reinitializing the start time of the test in the past are: time at which a leaking penetration (which has an obvious effect on the test data) was secured, accidental opening and later closing of a valve which has an obvious effect on the test data) was secured, accidental opening and later closing of a valve which has an obvious effect on the test data, or the time at which an airlock outer door was closed and the inner door was opened.

(6) The supplemental, or verification, test should start within one hour after the completion of the CILRT (Note: BN-TOP-1 requires a one-hour stabilization period). If problems are encountered in the start of the supplemental test, data recording must continue and be considered part of the CILRT until the problems are corrected and the supplemental test can begin.

(7) For the supplemental test, the size of the superimposed leak rate must be between 0.75 and 1.25 times the maximum allowable leak rate (La). The higher the value, the better. The supplemental test must be of sufficient duration to demonstrate the accuracy of the test. The NRC looks for the results to stabilize within the acceptance criteria rather than the results being within the acceptance criteria. Whenever the BN-TOP-1 methodology is being used, the length of the supplemental test cannot be less than approximately one-half of the length of the CILRT.

(8) During a CILRT, it may become necessary to reject or delete specific sensors or data points due to drifting of erroneous sensors, or data outliers. Data rejection criteria should be developed and used so that there is consistent, technical basis for data rejection. One example of an acceptable method for

data outliers is described in an Appendix to ANSI/ANS 56.8-1981. Sensor data rejection criteria should be plant specific and based upon a sensor's trend relative to the average scatter, slope, and/or absolute output of the sensor.

(9) An acceptable method for determining if the sum of Type B and C tests exceeds the 0.60 La Appendix J limits is to utilize the "maximum pathway leakage" methodology. This methodology is defined as the maximum leakage value that can be quantified through a penetration leakage path (e.g. the larger, not total leakage of two valves in series). This assumes a single active failure to the better of two leakage barriers in series when performing Type B or C tests.

(10) Test connections between containment isolation valves must be administratively controlled to ensure their leak tightness or otherwise be subject to Type C testing. One way to ensure their leak tightness is to cap, with a good seal, the test connection after its use. (Note: test connection lines which are between the containment and the first containment isolation valve must have two valves and a cap.) Proper administrative controls should ensure valve closure and cap reinstallation within the local leak rate testing procedure, and with a checklist prior to unit restart.

(11) Whenever a valve is replaced, repaired, or repacked during an outage for which Type A, B, and/or C surveillance testing was scheduled, local leak rate testing for the as-found as well as the as-left condition must be performed on that penetration. In the cases of a replaced valve, the as-found test can be waived, except during outages when a Type A test is scheduled, provided that no other containment isolation valve of similar design exists at any nuclear site owned by the same utility.

(12) The periodic retest schedule for each penetration subject to Type B or C testing, except for airlocks and penetrations employing a continuous leakage monitoring system, shall be tested every refueling outage, but in no case shall the interval be greater than two years.

(13) If local leakage measurements are taken to effect repairs in order to meet the acceptance criteria for Type A tests performed at reduced pressure, these measurements shall be taken at the test pressure Pt used for the Type A test.

c. CILRT Observations by Resident Inspectors

The inspectors reviewed activities related to the CILRT. The test was implemented with test procedure No. 0136, "Integrated Primary Containment Leak Rate Test," Revision 7, dated October 14, 1989. Activities conducted by the inspector included: verification of the placement of temperature and humidity instrumentation in the drywell and torus; witnessing, in part, the in situ testing of the test equipment; review of the licensee's procedure for tagging and independent verification of equipment; and verification of a system lineup in preparation for the test.

The placement of the CILRT temperature and humidity instruments was conducted in accordance with drawings contained in the contractor's test instructions. Personnel setting up the test equipment were knowledgeable and experienced. They had used this test equipment on two previous occasions at other facilities. The lead technician had 9 years experience conducting CILRT tests. The inspector noted during the in situ testing that the technicians were proficient at placement and preparation of the test equipment.

The inspector accompanied a licensed operator during the system alignment of the RCIC turbine exhaust in accordance with Procedure OCD 0136-29, "ILRT Isolation/Penetrations X-212, X-219 and X-223 RCIC Exhaust." The licensed operator completed the required information as he placed each tag. Upon identifying a valve misnumbered on the tag, the operator contacted control room personnel to verify the mislabeling and subsequently corrected the valve number on the tag. Good radiological practices were followed while conducting the system lineup.

The inspector observed the licensee's performance of test No.0138, Airlock leak test, Revision 4. This test was conducted following the completion of all maintenance on the drywell airlock and successfully demonstrated its integrity.

The following primary containment penetrations were verified to be in their proper positions prior to the CILRT:

Drywell penetrations
- X-10, RCIC Steam Supply;
- X-11, HPCI Steam Supply;
- X-20/DM 58, Demin Water Supply;
- X-21/AS 39, Service Air;
- X-22/ AI 574, Instrument Air;
- X-27 D,E&F, H O Analyzer;
- X-39A/RHR 74-2, Containment Cooling;
- X-39B/RHR 74-1, Containment Cooling;

Suppression Pool Penetrations
- X-200 A&B, Access Hatch;
- X-212/RCIC 10, RCIC Turbine Exhaust;
- X-219, RCIC Exhaust Vacuum Breaker;
- X-223, Condensate From RCIC Turbine;

The inspector also performed a walkdown of the Primary Containment Isolation System (PCIS). Details of this walkdown are contained paragraph 8, Engineered Safety Feature System Walkdown.

No violations or deviations were identified.

5. Containment Local Leak Rate Testing (LLRT) (61720)

The inspector reviewed the performance of Test No. 1037, Master Local Leak Rate Test, Revision 13, to assess the licensee's compliance with 10 CFR 50, Appendix J and the applicable ANSI standards. This review was conducted in conjunction with the licensee's CILRT described in paragraph 4.

Test No. 0137 was reviewed to ensure that it included all applicable containment pressure boundaries and containment isolation valves. The LLRTs are conducted at the CILRT peak pressure of 42 psig with the exception of the MSIVs, which were tested at 25 psig in accordance with TS 3.7.A.2.b.3. The LLRT program utilized the guidance given in ANSI N45.4-1972, Leakage Rate Testing of Containment Structures for Nuclear Reactors; and ANSI/ANS-56.8-1981, Containment System Leakage Testing Requirements.

A review of the licensee's data and calculations demonstrated that the maximum pathway leakage rate was 246.228 scfh. This rate is below the combined acceptance criteria of 275.2 scfh at 42 psi excluding the MSIV leak rate.

The TS requirement for the MSIVs requires that the maximum individual leak rate be below 11.5 scfh at 25 psig. The LLRT on the MSIVs rendered the following as-left results:

- MSIV A, inboard 0.25 scfh, outboard 0.86 scfh;
- MSIV B, inboard 4.3 scfh, outboard 5.84 scfh;
- MSIV C, inboard 4.75 scfh, outboard 6.68 scfh;
- MSIV D, inboard 4.70 scfh, outboard 10.85 scfh;

The inspector observed the LLRTs that were performed on MSIVs A & B. These MSIVs had work performed on them following the CILRT. Also observed was the local leak rate testing on the MSIV accumulator check valves. The inspector reviewed the procedures and observed the licensee personnel conducting the tests. All equipment used was verified to be within calibration. In addition, containment pressure boundary testing was observed during the CILRT and the Drywell Airlock LLRT.

No violations or deviations were identified.

6. Plant Startup From Refueling (71711)

The inspectors reviewed the licensee's actions for returning the plant and its systems to operable status following the refueling outage. Also reviewed were the activities with startup, core physics testing, and approach to criticality.

An inspector accompanied operations personnel on the following system lineups:

- HPCI Hydraulic Control and Lubrication System Prestart Checklist, No. 2154-35, Revision 2;

- Control Rod Drive System, No. 2154-09, Revision 29;

- Primary Containment System Prestart Checklist, No. 2154-15, Revision 13.

The following activities and tests were observed during the reactor startup:

- Shutdown Margin Demonstration, Test No. 0073, Revision 6, TS 3.3.A, 4.3.A;

- Rod Worth Minimizer Operability, Test No. 0212, Revision 16, TS 4.3.B.3(a) i-iv, 3.3.B.3;

- APRM Heat Balance Calibration, No. 0017, Revision 6, TS Table 4.1.2.

The inspectors also observed rod movements and the approach to critical.

No violations or deviations were identified.

7. <u>Cold Weather Preparation (71714)</u>

The licensee completed Test No. 1151, Winter Checklist, Revision 21 on November 15, 1989. The procedure provides for "laying up" portions of the heating and ventilating system and other systems as required either for freeze protection or to otherwise establish the winter mode of operation for these systems. The inspector reviewed the completed checklist and locally verified selected valve and heat tracing circuit positions.

No violations or deviations were identified.

8. <u>ESF System Walkdown (71710)</u>

The inspector performed a walkdown of the licensee's Primary Containment Isolation System (PCIS).

The inspector walked down the PCIS system by observing the material condition and reviewing past maintenance records for the following PCIS valves:

- Main Steam Isolation Valves 2-80A/B/C/D and 2-86A/B/C/D;
- RHR Shutdown Cooling Supply Valves 2029 and 2030;
- HPCI Turbine Steam Supply Isolation Valves 2034 and 2035;
- RCIC Turbine Steam Supply Isolation Valves 2075 and 2076;
- Main Steam Line Drain Valves 2373 and 2374;
- Torus Vent Valve 2383;
- Drywell Vent Valve 2386;
- Reactor Water Cleanup Isolation Valves 2397, 2398, and 2399;
- CGCS Valves 7422A/B, 7423A/B, 7424A/B, 7425A/B.

In addition the inspector verified proper breaker location, positioning and indication of selected breakers and performed a functional review of the logic and schematic diagrams.

The inspector observed the following surveillance testing of the PCIS

- Group I Isolation Simulated Automatic Initiation, Test No. 0152, Revision 7;

- Main Steam Line High Flow Group I Isolation Instrument Test and Calibration Procedure, Test Nos. 0051/0052, Revision 11;

- Main Steam Line Low Pressure Group I Isolation Instrument Test and Calibration Procedure, Test Nos. 0054/0055, Revision 8;

- Group II and III Isolation Simulated Automatic Initiation Test - SGTS Auto Initiation, Test Nos. 0150/0153/0154, Revision 15;

- HPCI High Steam Flow Sensor Test and Calibration Procedure and Group IV Isolation Valve Closure, Test Nos. 0056/0057/0155 Part I, Revision 8.

The inspector reviewed the most recent surveillance tests for:

- High Steam Chase Temperature Group I Isolation Instrument Test and Calibration Procedure, Test 0050, Revision 7;

- HPCI Steam Line High Area Temperature Test and Calibration Procedure Group IV Isolation Valve Closure, Test Nos. 0058/0059/0155 Part II Revision 4;

- RCIC High Steam Flow Sensor Test and Calibration Procedure and Group V Isolation Valve Closure, Test Nos. 0060/0061/0156 Part I, Revision 13;

- RCIC Steam Line High Area Temperature Test and Calibration Procedure Group V Isolation Valve Closure, Test Nos. 0062/0063/0156 Part II, Revision 7.

The inspector's review and walkdown of the PCIS indicated that the system was properly functioning and had been properly maintained. Valves in the system were installed correctly, appeared to be in good condition, and did not require an unusual amount of maintenance. Breakers, relays and valves were well labelled and breaker and relay cabinets were kept clean. The observation and review of the surveillance procedures demonstrated that instrumentation was properly installed, functioning, and significant process parameter values were consistent with normal expected values.

Instrument calibration dates were current. Overall, no significant deficiencies were noted with the PCIS and the system appears to be functioning adequately.

No violations or deviations were identified.

9. Monthly Maintenance Observation (62703)

Station maintenance activities of safety-related systems and components listed below were observed/reviewed to ascertain that they were conducted in accordance with approved procedures, regulatory guides and industry codes or standards and in conformance with technical specifications.

The following items were considered during this review: the limiting conditions for operation were met while components or systems were removed from service; approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and were inspected as applicable; functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were implemented; and, fire prevention controls were implemented.

Work requests were reviewed to determine status of outstanding jobs and to assure that priority is assigned to safety-related equipment maintenance which may affect system performance.

The following maintenance activities were observed/reviewed:

- WRA 89-4058, Repair Damper Leakage on V-AH-4A and 4B;
- WRA 89-50105, Remove/Replace No.12 Condensate Pump for Stuffing Box Repair;
- WRA 89-4085, Investigate/Repair Circuit Alarm on No.12 Diesel Generator Fast Start During Test 0189-3;
- WRA 89-4255, Repair/Replace Tubing to G-3B, Coolant Pressure Gauge Line to No.12 Diesel Generator;
- WRA 89-4293, Investigate/Repair Rod Block Monitor 8 Low Test Voltage;
- WRA 89-4253, Adjust LPRM 3D-28-29 Trip Point.

As of November 20, the licensee had a backlog of 142 active WRAs. This is down from the 615 that were active at the beginning of the inspection period and a high of 752 during week 5 of the outage.

No violations or deviations were identified.

10. <u>Monthly Surveillance Observation (61726)</u>

The inspectors observed surveillance testing and verified that testing was performed in accordance with adequate procedures, that limiting conditions for operation were met, that removal and restoration of the affected components were accomplished, that test results conformed with technical specifications and procedure requirements and were reviewed by personnel other than the individual directing the test, and that any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

The inspector reviewed/observed the following test activities:

- Secondary Containment Integrity Test, No. 0151, Revision 9;
- Reactor Coolant Pressure Boundary Pressure Test, Nos. 0255-20-IIC-1 (leakage) and 0255-20-IIA-1 (hydrostatic), Revision 7;
- RPS Channel Time Response Test Procedure, No. 0084, Revision 4;
- ECCS Auto Initiation Test, Including Loss of Offsite Power, Nos. 0036-2, 0039-2, 0093, 0103, 0111, 0113, 0117-1, 0117-2, 0189-3, 0452;
- ATWS Recirculation Pump Trips for Reactor Pressure and Level Trip Unit Test and Calibration, No. 0278a/0282a, cal No. 0280a/0284a, Revision 1;
- Group II and III Isolation Simulated Automatic Initiation Test, Nos. 0150 (SGTS), 0153 (Group II), 0154 (Group III), Revision 15;
- Shutdown Margin Demonstration, Test No. 0073, Revision 6;
- Rod Worth Minimizer Operability, Test No. 0212, Revision 16;
- RCIC Turbine Overspeed Trip Test, No. 1056, Revision 8;
- HPCI Turbine Overspeed Trip Test, No. 1057, Revision 6;
- HPCI System Tests Nos. 0108, 0255-06-IA-1 (valve operability) and 0255-06-III (pump operability), Revision 14;
- APRM Heat Balance Calibration, No. 0017, Revision 6;
- RCIC System Tests, No. 0114, Revision 22;
- Group I Isolation Simulated Automatic Initiation, Test No. 0152, Revision 7;
- Main Steam Line High Flow Group I Isolation Instrument Test and Calibration Procedure, Test Nos. 0051/0052, Revision 11;

- Main Steam Line Low Pressure Group I Isolation Instrument Test and Calibration Procedure, Test Nos. 0054/0055, Revision 8;

- Group II and III Isolation Simulated Automatic Initiation Test - SGTS Auto Initiation, Test Nos. 0150/0153/0154, Revision 15;

- HPCI High Steam Flow Sensor Test and Calibration Procedure and Group IV Isolation Valve Closure, Test Nos. 0056/0057/0155 Part I, Revision 8.

No violations or deviations were identified.

11. Licensee Event Reports

The inspector reviewed the following Licensee Event Reports (LERs) by means of direct observation, discussions with licensee personnel, and review of records. The review addressed compliance to reporting requirements and, as applicable, immediate corrective actions and that appropriate actions to prevent recurrence had been accomplished.

a. (Closed) Licensee Event Report (263/89022(DRP)): Failure of Emergency Service Water Pumps to Auto Start on Transfer to 1AR Transformer Due to Design Error.

   The control logic was changed so that the 13 and No. 14 ESW pumps automatically start on transfer to the 1AR transformer. Also, a review of 1AR loads was completed prior to startup to assure that all emergency loads required to be powered by 1AR have appropriate auto initiation features in their control logic. The resident inspectors reviewed these actions.

b. (Closed) Licensee Event Report (263/89027): Inadequate Review of Circuit Isolation Results in Reactor Water Clean Up (RWCU) Isolation Valve Closure.

   During performance of a modification procedure, the RWCU Hi Filter-Demin Inlet Temperature circuit was de-energized due to momentarily lifting a wire lead from a terminal block to allow termination of a second wire lead. This resulted in the closure of the RWCU primary containment isolation valves. The root cause of this event is a cognitive personnel error. Inadequate attention was was given to other circuits that could be affected by the modification isolation. The need to review redundant drawings and adequately verify as-built configuration for the circuit isolations involving lifted leads or jumpers will be emphasized during training.

c. (Closed) Licensee Event Report (263/89028): Modification Review Identified Potential for Degraded ECCS capability.

   A concern was identified by the plant engineering staff during the review of a modification to correct a deficiency in the power supply to the Low Pressure Coolant Injection (LPCI) valves. The concern is a potential degraded condition of the electrical power supplied by the EDG during a LOCA with a loss of offsite power. This could make the selected LPCI injection valves and one division of Core Spray inoperable. Degraded voltage or frequency for onsite power sources were not postulated failure modes and were not part of the design basis.

The licensee has installed additional relays to monitor the LPCI swing bus for abnormal power conditions. Under degraded power conditions, (i.e., overvoltage, undervoltage, or abnormal frequency) the relays will initiate a swing bus transfer from Division I (normal) to Division II (alternate) for the bus supplying power to the LPCI injection valves.

See Inspection Report 50-263/89030 for additional information and analysis.

d. <u>(Open) Licensee Event Report (263/89029(DRP))</u>: Degradation of Secondary Containment due to Design Deficiencies and Inadequate Testing Procedures.

This is the LER for the secondary containment issue that was previously discussed in Inspection Report 263/89023. The root causes of this event are design inadequacy and personnel error resulting in inadequate testing procedures. The original design resulted in a condition where non-safety related equipment (reactor building plenum exhaust fans) could interfere with the operation of safety-related equipment (SGTS and Secondary Containment). Operation of the reactor building plenum exhaust fans could result in the bypass of the SGTS system during design basis accidents when offsite power remains available.

On October 31, 1989, following repairs to dampers and seals, a secondary containment capability test was satisfactorily performed with the Reactor Building Plenum Exhaust Fans secured. A safety evaluation was performed to ensure that 10 CFR Part 100 limits would not be exceeded using Regulatory Guide 1.3 source terms. This evaluation determined that if bypass flow is terminated within 45 minutes of secondary containment isolation, then doses will remain within the 10 CFR Part 100 limits. On November 4, 1989 operating procedures were revised to specify the manual actions required to terminate the bypass flow within 45 minutes. Training was completed on these procedures and secondary containment was declared operable on November 5, 1989. (See also Inspection Report 50-263/89029(DRP)).

This item will be closed when the associated unresolved item 263/89023-01 is closed.

e. (Open) Licensee Event Report (263/89030(DRSS)): Security Badging Problem Leads to Unauthorized Access.

Site Security was notified by corporate security that an IRM employee was cleared and given access to the plant without completing a psychological test. The individual had previously worked for IRM but there was a service break and it had been over a year since the individual had last been tested.

f. (Open) Licensee Event Report (263/89031): RPS Initiation During ILRT Restoration.

During restoration of the reactor vessel level instrumentation following the ILRT, the actual reactor level was at -25" in preparation for the reactor pressure vessel operational hydrostatic test. When the level instrumentation was restored, it was equalized from +50" to the actual level of -25." When level indication reached +9," a reactor scram signal was received. All rods were full in prior to and during this event. A Group II isolation signal was received resulting in a shutdown cooling isolation and SGTS system initiation. A Group III signal was also received; however, the RWCU system was already isolated.

g. (Open) Licensee Event Report (263/89032): Group I Isolation due to Loose Wire in Panel C41.

The MSIV inboard isolation valves were open in preparation for Reactor Coolant Pressure Boundary Pressure Test when they closed unexpectedly. A loose wire was found in the AC supply in breaker panel C-41, terminal AA9.

h. (Open) Licensee Event Report (263/89033): Initiation of Safety Relief Valve (SRV) Low Low Level Set Logic.

There was an ESF actuation due to the initiation of Division II Low Low set logic during the refueling outage Reactor Pressure Vessel Hydrostatic test resulting in the operation of the G and H Safety Relief Valves (SRVs). Reactor pressure vessel pressure was 1008 psig. The initiation signal occurred as a result of I&C technician performance of level transmitter sensing line excess flow check valve leak test. Rapid pressure fluctuations due to the seating of excess flow check valve resulted in a low low set initiation signal. The low low set valve handswitches on the control board had been placed in pull-to-lock, but the Division II low low set, for the Alternate Shutdown System, had not been placed in inhibit. This combination of events caused the SRVs to open. Reactor pressure decreased from 1008 psig to 52 psig.

i. (Open) Licensee Event Report (263/89034): Spurious Toxic Analyzer Trip Causing EFT to Initiate.

The spurious trip caused the EFT to realign to the toxic chemical emergency mode. The cause is unknown and under investigation.

j. (Open) Licensee Event Report (263/89035): RPS Actuation Caused by Spurious Spike in IRM System.

The RPS received a spurious spike high from IRM channels No. 14 and No. 18. Eight out of eight of the IRMs showed an increase. There were no surveillances being performed on any systems. Additionally, there was no maintenance, welding or radiographic testing on any systems associated with or in the proximity of the RPS or IRM systems.

h. (Open) Licensee Event Report (263/89036): EFT Initiation Caused by Voltage Reduction.

During the performance of Special Procedure 8876, Load Test of the No. 12 EDG, the output bus experienced a voltage reduction when the No. 12 core spray pump was started. This caused a trip of the EFT system to the E mode from the toxic chemical trip logic actuating due to the degraded voltage.

l. (Open) Licensee Event Report (263/89037): Reactor Mode Switch Overshoot to Run and Subsequent Reactor Protection System Actuation.

While placing the reactor mode switch in "startup," the "run" contacts were inadvertently picked up which resulted in a Group I isolation from low steam line pressure and an RPS trip from MSIV closure.

m. (Open) Licensee Event Report (263/89038): Scram Caused by Spurious Actuation of High Pressure Sensor While in Half Scram Condition for the Performance of Surveillance.

See Paragraph 3.c.

No violations or deviations were identified.

12. Management Meeting (30702)

The Branch Chief, Reactor Projects Branch 2, DRP, visited the site on October 26, 1989, and toured various plant areas including: suppression pool room, standby gas treatment room, main plant plenum exhaust fan room, RCIC/HPCI rooms, turbine building, control room, and various other areas within the reactor building. Areas inspected were well maintained and reflected good radiation safety practices and outage controls. At the conclusion of the inspection, the inspectors met with Messrs. D. Antony and B. Day to discuss the recent large number of reportable events. Mr. Antony's review of these reports showed that only three events were attributable to personnel error, two reportable events were voluntary and four events were related to security. Specifically, the following issues were discussed with the licensee; secondary containment deficiencies and proposed modifications; licensee identified EQ deficiencies and proposed modifications; jet pump brace crack and the General Electric analysis; containment integrated leak rate testing and local leak rate testing or repairs needed for main steam isolation valves A/B lines; the installation and testing of the No. 13 diesel generator; and the LPCI swing bus modification.

The licensee has examined the large number of reportable events and has concluded that no systematic problem existed (e.g., personnel error trends or excessive overtime usage) other than what could normally be expected for a 79-day extensive outage. The inspector, however, did express concern regarding the large amount of overtime expended (63%) for September and October 1989. Messrs. Antony and Day indicated that plant startup was still scheduled for November 4-6, 1989, and acknowledged the concern regarding overtime usage and attention to details by their staff.

An unannounced inspection by the Branch Chief and the Branch Project Engineer was conducted on the evening of November 17, 1989. The purpose of this inspection was to informally assess, through interviews with the shift on duty, what effect, if any, the amount of overtime being worked during the outage had on the performance of their duties. The control staff was also questioned regarding the extent of training they had on the new control room modifications as well as their familiarity with the deficiencies of the SGTS concerning secondary containment integrity and the reactor building plenum fans.

The interviews gave no indication that the amount of overtime being worked had any adverse effect on the performance of their duties. In addition, the operators demonstrated that they had been adequately trained on the control room modifications, and were quite familiar with the new operating instructions for the operation of the SGTS in accident conditions.

13. Regional Requests for Information

a. A request was made by the DRP director in response to an NRR request on the licensee's System Engineer program. Below are the specific questions and the response to them as it pertains to the current program at Monticello.

1. Do they have a System Engineer (SE) program?

Yes.

2. What are the major functions of the SE's at Monticello?

To attain a detailed understanding of assigned systems and equipment as well as a day-to-day status of assigned systems or programs. Evaluate surveillance test results and system or program performance. Prepare direct and document special tests as may be required to evaluate system performance or to determine the cause of system malfunctions. Provide technical support for maintenance activities. Order spare parts. Routinely inspect accessible portions of systems and initiate actions or correct defects in material condition and/or housekeeping. Investigate industry operating experience (NRC, INPO) and prepare responses. Implement modifications as required. Assist the training department as requested in training sessions associated with assigned systems.

3. Do they report onsite?

   Yes. The SE's report to the Superintendent of Engineering and Radiation Protection who reports to the Plant Manager.

4. Approximate number of SE's.

   Operations engineers - 18
   Technical engineers - 5
   Maintenance engineers - 2

5. Approximate experience level of SE's.

   4 - 6 years.

6. How long has the SE program been in effect at Monticello?

   18 years. Since the plant was built.

7. How would you rate the SE programs positive effect at your plant?

   SALP 1. ETS has received a SALP 2 in recent rating periods, but the SE's have had an overall positive effect on the operation of the plant.

8. Any additional comments on your licensee's SE program?

   The program has a positive effect. The system engineers carry a very heavy work load, particularly during outages. The licensee intends to hire seven additional SE's soon. Two of these additional positions will be in the area of procurement.

b. The DRP Division Director, in response to the Executive Director for Operations concerns regarding the potential for inadvertent criticalities during fuel movement, requested answers to the following questions:

   1. Determine whether the plant uses intermediate refueling configurations before achieving final core configuration or whether fuel is only loaded in its final core location.

      The licensee performed a complete off load of the core for the most recent refueling outage to facilitate fuel sipping and ISI activities on the vessel. During other refueling outages, the plant has used intermediate refueling configurations.

2. Determine whether or not sufficient analyses exist to support loading procedures.

   Reviews of core load analyses and discussions with the lead nuclear engineer indicate that sufficient core analyses to support core loading procedures do exist. This past outage, the licensee implemented an extra precaution of removing the shorting links from the Source Range Monitor (SRM) scram logic. This precaution resulted in a non-coincident scram condition wherein any single high reading on any SRM would result in a scram. These conservative actions resulted in the licensee experiencing two reportable events: 263/89-024 & 263/89-026. The rods remain in the fuel cell during fuel bundle removal and replacement. The fuel cells around the SRMs are the last cells to be removed from the core and the first cells to be replaced.

3. Determine who does the analysis of the refueling configurations.

   The fuel vendor, General Electric, does the final core loading analysis. The licensee performs the analysis of the intermediate positioning of the fuel including fuel pool location. This is done with the use of a computerized accountability program to review all intermediate positions.

4. Determine whether or not adequate procedures exist for refueling the core.

   The licensee's fuel movements are highly proceduralized. All movements, sequencing, and locations are specified in the refueling procedure "move sheets." Any deviations from these "move sheets" requires the approval of two SROs and a nuclear engineer.

5. Determine whether or not the licensee is aware of the potential concern of IN 89-51.

   The licensee is aware of the concerns presented in IN 89-51 and formally addressed them through their internal IN review program.

14. <u>Exit Interview (30703)</u>

The inspectors met with the licensee representatives denoted in Paragraph 1 on November 27, 1989. The inspectors discussed the purpose of the inspection and the findings.

The inspectors also discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the inspectors during the inspection. The licensee did not identify any documents/processes as proprietary.