U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-155/87026(DRP)

Docket No. 50-155 License No. DPR-6

Licensee: Consumers Power Company
212 West Michigan Avenue
Jackson, MI 49201

Facility Name: Big Rock Point Nuclear Plant

Inspection At: Charlevoix, Michigan

Inspection Conducted: October 16, 1987 - December 14, 1987

Inspector: S. Guthrie

Approved By: I. N. Jackiw, Chief
Projects Section 2C

12-29-87
Date

Inspection Summary

Inspection on October 16, 1987 - December 14, 1987 (Report No. 50-155/84-17(DRP))
Areas Inspected: Routine, unannounced inspection conducted by the Senior Resident Inspector of Operational Safety, Maintenance Operation, Surveillance Operation, Reactor Trips, IE Bulletins, Management Meetings, Licensee Event Report Followup, and Security.
Results: Of the nine areas inspected, no violations or deviations were identified. No significant safety items were identified.

DETAILS

1. Persons Contacted

T. Elward, Plant Superintendent
*G. Petitjean, Planning and Administrative Services Superintendent
*G Withrow, Engineering Maintenance Superintendent
*R. Alexander, Technical Engineer
*R. Abel, Production and Plant Performance Superintendent
L. Monshor, Quality Assurance Superintendent
D. Staton, Shift Supervisor
W. Trubilowicz, Operations Supervisor
*J. Beer, Chemistry/Health Physics Superintendent
D. Kelly, Maintenance Supervisor
D. Ball, Maintenance Supervisor
W. Blosh, Maintenance Engincer
M. Acker, Senior Engineer
J. Toskey, General Engineer
L. Darrah, Shift Supervisor
J. Horan, Sh'ft Supervisor
R. Scheels, Shift Supervisor
J. Boss, Reactor Engineer

The inspector also contacted other licensee personnel in the Operations, Maintenance, Radiation Protection and Technical Departments.

*Denotes those present at exit interview.

2. Operational Safety Verification

The inspector observed control room operations, reviewed applicable logs and conducted discussions with control room operators during the inspection period. The inspector verified the operability of selected emergency systems, reviewed tagout records and verified proper return to service of affected components. Tours of the containment sphere and turbine building were conducted to observe plant equipment conditions, including potential fire hazards, fluid leaks, and excessive vibrations and to verify that maintenance requests had been initiated for equipment in need of maintenance. The inspector by observation and direct interview verified that the physical security plan was being implemented in accordance with the station security plan.

The inspector observed plant housekeeping/cleanliness conditions and verified implementation of radiation protection controls. During the inspection period, the inspector walked down the accessible portions of the Liquid Poison, Emergency Condenser, Reactor Depressurization, Post Incident, Core Spray and Containment Spray systems to verify operability. The inspector also witnessed portions of the radioactive waste system controls associated with radwaste shipments and barreling.

a. On November 9 the licensee commenced a normal shutdown of the reactor to enter a scheduled outage of estimated four days duration to repair Reactor Depressurization System (RDS) depressurization valve top assemblies and repack RDS isolation valves. The facility had operated for several weeks at approximately 0.6 gpm unidentified leak rate, below the administrative limit of 0.8 requiring power reduction and corrective measures. Normal values for unidentified leakage are approximately 0.3 gpm.

   The unit was returned to service November 14 following a normal startup. Leak rate calculations performed at normal reactor pressure and temperature following startup indicated RDS repairs had been ineffective in reducing the unidentified leak rate. Unidentified leak rate, which did not include that portion of RDS leakage which could be collected in specially constructed collection rigs mounted on the RDS tail pipes, increased from 0.642 gpm on November 14 to 0.752 on November 20. During the shutdown a reactor scram occurred. The event is discussed in Section 5 of this report.

b. On November 22 following replacement of RDS depressurization valve top assemblies on trains A and C, a startup was commenced. During approach to criticality double notching was observed during withdrawal on three different control rod drives and all drives were then fully inserted in the reactor. During normal rod drive withdrawal a relay interrupts the withdrawal signal after a prescribed time interval, thus limiting rod movement to one notch. In this instance operators observed the rod traveling two notches before settling into a new position. An earlier instance of double notching on withdrawal occurred during the November 14 startup but could not be duplicated for investigation. The licensee investigated rod drive timing relays and determined the timing relays were set within specifications. During trouble shooting two additional drives were observed double notching.

   The licensee experimented with different reactor recirculation pump discharge valve positions, and during testing identified three additional double notching drives. Testing results indicated that because the rod drive water discharges to the suction of recirculation pump No. 2, fully opening the pumps discharge valves reduced the back pressure on the rod drive system, permitting faster rod drive water flow and resultant faster rod travel time. For those drives with rate set valves adjusted to permit relatively fast rod travel time of approximately 25 seconds, the increased rod drive flow rate caused the drive to travel past the first notch before the timing relay could interrupt the operation. The licensee retested all drives and adjusted rate set valves as indicated by test results conducted with recirculation pumps at full flow with the discharge valve fully open. Normally, rod drive timing and any required adjustments are performed during refueling outages with the reactor head removed and recirculating pumps idle. The licensee undertook an evaluation of procedures controlling rod drive operation and testing to determine the effects of testing at plant conditions not representative of those seen at power operation.

Rod drive diagnostic testing revealed two drives which exceeded Technical Specifications 5.2.2.(a)(IV). The specification limits the speed of control rod drives withdrawal to 23 seconds minimum for continuous travel over the full length of the stroke. Drive B-1 timing was 22.6 seconds and drive D-2 was found to be 21.7 seconds. The increased flow of control rod drive water as described above was the apparent explanation. The reactor physics package for the current cycle calculates that a free fall rod withdrawal, which withdraws the rod from full in to full out in 0.60 seconds, does not exceed the maximum allowable deposited enthalpy specified by the fuel vendor. Because the 21.7 second withdrawal time of drive D-1 is well within the limiting criteria for the rod free fall accident, the licensee concluded no fuel damage would have resulted had the drive been fully withdrawn in a continuous motion. During normal operation rods are withdrawn one notch at a time. The licensee adjusted both drives. Drive B-1 was adjusted to 30.5 seconds and drive D-2 was reset to 29.0 seconds as tested with recirculation pumps at full flow with discharge valves fully open. Reactor startup was commenced at 1:00 a.m. November 23, but was interrupted by a reactor scram at 2:47 a.m. That scram is described in Section 5.b of this report. The reactor was successfully restarted following repairs to nuclear instrumentation.

During the period November 23-25 the inspector interviewed operators on several shifts to verify each operator was fully versed in the observed control rod malfunction, the identified cause, and corrective action. The inspector determined that operators performing startup activities, while aware of instances of double notching of control rods, were in some instances not aware of the effect of recirculation pump discharge valve position on rod travel times. The licensee, when informed by the inspector, immediately placed a requirement in the Daily Orders for operators to review the Deficiency Report describing the event and its resolution.

The inspector noted that during the several startups and shutdowns and scrams occurring during the period November 9-23, operators consistently performed the evolutions and required responses in accordance with procedural requirements and without operator error or lapses in administrative control.

c. On December 2 the inspector observed portions of the reactor shutdown initiated in response to indications of steam leakage in the pipe tunnel. Immediately upon receipt of control room alarms from dew cells located in the pipe tunnel and visual verification of steam visible from the turbine deck operators commenced power reduction to permit pipe tunnel entry for inspection. Area radiation monitors and sustained elevated offgas release rates were not observed because of the prompt power reduction. Inspection revealed through-the-wall erosion in the shell of the low pressure side of the high pressure feed heater. Reactor power was further reduced to permit nondestructive testing and repair of the defect. The reactor was

maintained above 212 F and the shutdown cooling system was in operation during the maintenance period. Testing and corrective maintenance is described in Section 3 of this report.

Upon completion of repair activity the reactor reached criticality at 5:13 a.m. December 7 and the turbine was synchronized at 10:27 a.m. During startup activities daily water chemistry sampling required by Technical Specifications was delayed approximately two hours when calibration of feedwater instrumentation resulted in prohibition of containment access.

No violations or deviations were identified in this area.

3. Monthly Maintenance Observation

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.

a. On October 28 during a routine tour the inspector identified steam rising from the top assembly of D RDS depressurization valve. Investigation revealed steam escaping from a stud used to bolt the top assembly to the body of the valve. The licensee, as part of repair activities on RDS valves during the outage commencing November 9, performed cleaning and nondestructive testing of the mating surfaces between the two valve components. Leakage at the stud was not observed following repairs.

b. On November 9 and 10 the inspector observed disassembly and inspection of RDS depressurization valves A and B following top assembly removal. Based on direct observation and discussion with licensee personnel the inspector determined that the seat had visible cracks, the disc was visibly worn from being used as a lapping tool during previous repairs, and discolorations in both disc and seat showed evidence of steam leakage. Original valve design calls for seat angle to differ from disc angle, but long term

use of the disc to lap the seat had resulted in nearly the same angle for both disc and seat. The inspector questioned the use of a stellite disc to lap a stellite seat and was informed by the licensee that a cast iron lapping tool would be fabricated for future use. The inspector identified to the licensee a visible flat spot or depression on the face of the B valve's disc, but subsequent blue checks during reassembly showed it to be outside the seating area.

The inspector verified that the licensee had devised and implemented an acceptable system for verifying correct reconnection of electrical leads on both valve coils as discussed in Section 4.a of Report No. 155/87023.

c. On November 10 the inspector observed testing of steam drum relief valve serial Number A-5. The single stage spring loaded relief valve was removed from service for testing to satisfy a commitment made by the licensee to verify the operability of steam drum relief valves following repeated occurrences of disc to seat adhesion that resulted in as-found set points approximately 200 psi above specification. Incidents of unacceptable relief valve performance and licensee corrective actions are detailed in Section 4.a of Report No. 155/87011.

Valve No. A-5, one of six installed on the steam drum as primary plant overpressure protection, has a specified setpoint of 1535 psig +/- 15 psig. Testing was performed using compressed nitrogen and at ambient temperature in accordance with Surveillance TR-28 Testing of Steam Drum Relief Valves. As-found lift pressure was 1484.6 psig, 50.4 psig below set point and 35.4 psig below tolerance. A second test established repeatability at 1488.1 psig. The adhesion of disc to seat which resulted in elevated lift pressures during tests earlier in 1987 was not in evidence.

During the test the inspector questioned the procedural requirement of Surveillance TR-28 to reposition the nozzle blow down ring from position 18 to position 2 prior to the as-found test. The technical justification of the long standing practice could not be established by the licensee. The licensee maintained that the valve manufacturer concurred with the adjustment. The inspector provided the licensee with data from LER 83-74 (valves failed to meet "as found" acceptance criteria) describing the Palisades Plant's experience with main steam relief valve as-found setpoints above the specified limit. The licensee attributed the Palisades malfunction to adjustments made to each valve's blowdown ring prior to as-found testing. The Palisades procedure was revised to eliminate the requirement for blowdown ring adjustment.

To address the inspector's concern the licensee on November 11 performed two additional lift tests on Valve No. A-5 in an effort to demonstrate that blowdown ring position has no effect on set point. The first lift was made with the blowdown ring at position 2 and results were consistent with the tests performed November 10. The

second test was conducted with the blowdown ring at its normally installed position number 18 and resulted in no appreciable difference in lift points. The inspector questioned the validity of any engineering judgements made on the basis of these additional lift because (1) the tests did not determine the as-found condition of the valve, (2) seat leakage through the valve's disc and seat was observed at a pressure well below the lift point, indicating the repeated testing had prevented reestablishment of the disc to seat seal typical of the as-found valve condition, and (3) the valve body had cooled significantly from the previous day's testing.

On November 11 the Plant Review Committee convened to assess the safety significance of the low setpoint found on valve A-5. The PRC concluded that the 1484.6 psig setpoint would not impede operation of the emergency condenser, which operates at 100 psig above reactor pressure of 1335 psig and approximately 100 psig below steam drum relief valve setpoints. The liquid poison system, which operates on siphon effect was expected to operate normally. A relief valve with a low setpoint that might stick in the open position represents a loss of coolant accident that is an analyzed accident condition against which the plant is protected. Applicable industry codes do not address setpoint test results below the setpoint. As a conservative measure to verify the disc to seat adhesion phenomenon was not in evidence the licensee elected to remove and test a second steam drum relief. Valve No. A-4 was tested using Surveillance TR-28 with the blowdown ring in position 2. The valve has a specified lift point of 1585 +/- 15 psig and lifted on the as-found test at 1581.9 psig.

A review by the inspector and Region III concluded that the disc to seat adhesion was not in evidence and that the low relief valve setpoint did not impose an undue safety hazard while installed in the plant. The testing of at least one additional relief valve during the upcoming refueling outage in approximately 90 days will be observed to determine if the low setpoint on valve A-5 was an isolated incident or is representative of a programmatic deficiency in the licensee's testing or setpoint calibration methodology. The licensee committed to resolve the apparent conflict between Palisades and Big Rock procedures that address position of the blowdown ring and its effect on valve setpoint. The licensee is considered to have met all commitments made to the staff concerning relief valve testing arising from the concerns over disc to seat adhesion and resultant high relief valve setpoints.

d. The HP feed heater is a single pass U tube heat exchanger with high pressure feed water on the tube side and low pressure extraction steam on the shell side. Extraction steam is drawn off the turbine and at full power is approximately 185 psig. The heat exchanger is constructed with an internal steam deflector to prevent direct impingement of steam on the U-tubes. The licensee performed nondestructive testing and constructed ultrasound maps of the

heat exchanger's shell in both of the locations where the internal deflector would cause the steam to erode the shell's interior surface. Dye penetrant testing was performed in the area of the erosion to verify the defect had not developed into a structural crack. The turbulence resulting from the deflected steam eroded the shell side metal from the inside, reducing it from a nominal 0.562 inch thickness to as little as 0.047 - 0.097 inches in the area adjacent to the defect.

The licensee welded the eroded area and constructed a patch from 0.25 inch steel rolled to the contour of the 30 inch diameter of the heat exchanger's shell. The patch was sized to cover the areas on both sides of the shell where ultrasound tests indicated wall thinning, and was welded directly to the shell material. Attempts were made to inspect the heater's interior for corrosion and structural damage using a baroscope, but the restrictive contours of the internal deflector prevented access. Wall thicknesses were verified in the area of the only other deflector in the HP feed heater and were also verified in the areas of possible erosion on the low and intermediate pressure feed heaters. The licensee expects to perform major repairs to the HP feed heater and extraction line during the 1988 refueling outage.

Prior to startup December 7 the licensee unsuccessfully attempted to hydrostatically pressure test the heat exchanger's shell side. Several leaking valves prevented reaching test pressure. Visual inspections of the repaired area were conducted during startup. A humidity indicator with remote read out and a chart recorder was installed in the area of the repairs to detect minor leakage. The licensee was sensitive to the need for limited personnel access to the heat exchanger, which is located in the locked pipe tunnel not normally accessible during operation except for weekly inspections.

No violations or deviations were identified in this area.

4. Surveillance Observation

a. On November 13 the inspector observed performance of Surveillance TV-07, Control Rod Drive Scram Test from Notch 23. The surveillance, which is performed prior to startup to verify the ability of each control rod to scram from the full out position, was successfully completed in accordance with procedural requirements.

b. On November 13 the inspector observed from the control room the performance of Surveillance T90-12, Reactor Depressurization System (RDS) Valve Test. The surveillance involves pressurization of portions of RDS piping to normal plant pressure (1335 psig) with compressed nitrogen and actuation of the RDS depressurization valve from the control room. A strip recorder verifies depressurization of the test pressure when the valve is actuated. The test was successfully completed in accordance with procedural requirements.

c. The inspector on November 17 reviewed the licensee's preparations for cold weather. The inspector observed preparations which had been completed and documented on the licensee's cold weather check off sheet in the screen house, diesel generator room, sphere ventilation shed and turbine building. The inspector reviewed maintenance orders issued to repair inoperable air louvers in the turbine room.

d. On November 25 the inspector observed performance of monthly surveillance T30-22, ECCS Valve Test. The surveillance verifies the operability of four core spray valves. The test was performed in accordance with procedural requirements.

5. Reactor Trips

a. On November 9, approximately three hours into a normal shutdown and with the reactor subcritical at approximately 15 x 10-3 per cent power, the reactor tripped on a spurious upscale/downscale signal. The trip occurred during downscaling of the three picoammeter channels. With picoammeter No. 1 downscale with a downscale alarm inserted, channel No. 3 was downscaled. A spurious high flux signal caused the trip signal. The susceptability of reactor trips from spurious upscale/downscale signals with their origin in picoammeter circuitry is a long known operating characteristic of the facility associated with electrical noise at very low power levels. All partially withdrawn control rods inserted fully and all systems functioned normally. The licensee made the required notifications.

b. On November 23 at 2:47 a.m. the reactor tripped during approach to criticality. With the reactor slightly subcritical operators observed fluctuations in intermediate range channel 5 period indications ranging from +30 seconds to -100 seconds. The second intermediate range channel displayed no such fluctuation, and with reactor power sufficient to register in the lower ranges of power range instrumentation, operators observed no power level oscillations. While under observation by operators the reactor tripped on short period. All systems functioned normally and the required notifications were completed. Cause of the erratic indication was determined to be electronic failure of channel 5 nuclear instrumentation. The circuitry was replaced and tested and restart commenced at approximately 1:00 p.m. November 23.

No violations or deviations were identified in this area.

6. Management Meeting

On October 21 the licensee participated in a management meeting with members of the Region III staff in Glen Ellyn. During the meeting the licensee discussed the implementation of the trial Enhanced Performance Incentive Program implemented approximately 18 months ago to provide reduced site Quality Assurance department involvement with selected site departments who have demonstrated exemplary performance in meeting quality assurance requirements. The licensee reviewed the program philosophy and requirements, described the audits, surveillances and

inspections performed during the trial period, and proposed the formalized continuation of the program through a change in the Topical Report (CPC-2A). The staff concurred in the licensee's plan to continue the program for the one site department now participating pending review of the proposed CPC-ZA changes. The licensee presently has no additional candidates for the reduced involvement program.

7. Licensee Event Reports Followup

Through direct observations, discussions with licensee personnel, and review of records, the following event reports were reviewed to determine that reportability requirements were fulfilled, immediate corrective action was accomplished, and corrective action to prevent recurrence had been accomplished in accordance with technical specifications.

By letter dated November 12 the licensee submitted Licensee Security Event Report (BRP-87-01.5), Vital Area Barrier Breach, required by 10 CFR73.71(c). Contents of the report contain safeguards information exempt from public disclosure in accordance with 10 CFR73.21(c). The event is the subject of Inspection Report No. 155/87021(DRSS) and was discussed with the licensee at an enforcement conference in Region III on October 21, 1987. The LER is considered closed.

By letter dated November 13 the licensee submitted Revision 3 to LER 87-003, Inoperable Primary System Safety Valves. The LER was submitted as an informational update to report the results of safety valve testing conducted November 10-11. The update documented that test results showed no evidence of disc to seat adhesion that earlier had resulted in lift points above specification. These elevated lift points were the subject of the original LER submittal. A detailed description of the November 10-11 testing is presented in Section 4.c of this report. The LER and Revision 3 are considered closed.

By letter dated December 1 the licensee submitted LER 87-011, Reactor Trip-Spurious Upscale/Downscale trip. The reactor trip occurred November 9 during a shutdown to perform RAS top assembly replacement. The event is described in Section 6.a of this report. The LER is considered closed.

8. Security

a. On December 8 the inspector observed a site employee enter the site with a sheathed knife normally used in outdoor sports. The inspector questioned the need to bring into the protected area a device which was not a work related tool and which could be perceived as a weapon. Interviews with several security officers revealed an inconsistency among officers regarding the admissibility of knives of that description. The licensee elected to prohibit the knife's entry and, at the inspector's request, committed to develop a prohibited items list and provide clear instructions to security officers on what items are prohibited from the site.

b. On December 9 the inspector observed through the window in the door to the Central Alarm Station (CAS) the security supervisor on watch to have the appearance of inattentiveness. Specifically, the interior lights had been switched off, the supervisor was in a fully reclined position in his chair with his feet up on the panel, and for a period of several seconds his eyes were observed to be closed. The inspector informed licensee management. The supervisor was interviewed by the licensee and counselled on the importance of professional conduct and the appearance of attentiveness at all times. The licensee committed to develop and implement a policy which clearly conveys to security personnel staffing alarm stations expectations for appropriate behavior to ensure attentiveness while on duty.

9. Bulletins

As required by I.E. Bulletin 87-02, Fastener Testing to Determine Conformance With Applicable Material Specifications, the inspector participated with the licensee in the selection of 20 samples of safety and non-safety related fasteners from current stock. Nuts were included for all fasteners selected. The inspector noted that because the licensee's procurement practices result in nearly all fasteners being purchased as safety grade stock, only seven of the ten required non-safety samples available on site. Using guidance from the Staff's Technical contact, the inspector requested that the licensee obtain an additional three samples of safety grade fasteners to satisfy the requirement for 20 samples.

10. Exit Interview

The inspector met with licensee representatives (denoted in Paragraph 1) throughout the month and at the conclusion of the inspection period and summarized the scope and findings of the inspection activities. The licensee acknowledged these findings. The inspector also discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the inspector during the inspection. The licensee did not identify any such documents or processes as proprietary.