U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-155/85014(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, MI 49720

Inspection Conducted: July 30 - October 31, 1985

Inspector: S. Guthrie

Approved By: R W DeFayette for D. C. Boyd, Chief
Projects Section 1B

12/11/85
Date

Inspection Summary

Inspection on July 30 - October 31, 1985 (Report No. 50-155/85014(DRP))

Areas Inspected: Routine, unannounced inspection conducted by the Senior Resident Inspector and a Region III inspector of Licensee Actions on previous Inspection Findings, Operational Safety, Maintenance Operation, Licensee Event Report Followup, Licensing Activities, Headquarters Requests, and TMI action item followup. The inspection involved a total of 280 inspector hours by two NRC inspectors.

Results: Of the six areas inspected, no violations or deviations were identified in five areas. Several violations were identified in the remaining area and these were discussed with the licensee in an Enforcement Conference. These violations and the resultant enforcement action will be addressed under separate cover.

DETAILS

1. Persons Contacted

*D. Hoffman, Plant Superintendent
G. Pettijean, 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
R. Barnhart, Senior Quality Assurance Administrator
P. Donnelly, Senior Review Supervisor, Nuclear Activities Dept.
J. Lovell, Quality Control Supervisor
W. Blissett, Shift Supervisor
D. Swem, Senior Engineer
G. Sonnenberg, Shift Supervisor
D. Staton, Shift Supervisor
*W. Trubilowicz, Operations Supervisor
J. Beer, Chemistry/Health Physics Superintendent
E. Evans, Senior Engineer
R. Brady, Senior Plant Technical Analyst
J. Tilton, General Engineer
D. Kelly, Maintenance Supervisor
D. Ball, Maintenance Supervisor
W. Blosh, Maintenance Engineer
M. Acker, Senior Engineer
J. Toskey, General Engineer
J. Kneeland, Reactor Engineer
L. Darrah, Shift Supervisor
J. Horan, Shift Supervisor
R. May, Shift Supervisor
R. Scheels, Shift Supervisor
J. Warner, Property Protection Supervisor
T. Fisher, Senior Quality Assurance Administrator
S. Bartoski, General Quality Assurance Consultant
R. Krchmar, General Quality Assurance Analyst
*R. Burdette, Chemistry/Health Physics Superintendent (acting)

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

*Denotes those present at exit interview.

2. Licensee Action on Previous Inspection Findings

(Open) 155/84002-BB, Failures of General Electric Type HFA Relays. The inspector reviewed the licensee's October 17, 1984, response to IE Bulletin 84-02 in which the relays to be replaced are listed. This was compared to the preliminary outage schedule which details the work to be performed during the fall, 1985, outage. Based upon this comparison the proposed licensee action should complete all requirements of the Bulletin. At the close of the inspection period the relays had been replaced but testing had not been completed.

(Open) Unresolved Item (155/85007-02), Licensee's Corrective Action to Reduce Human Error. The licensee continues to experience the type of event that is based on human error. The inspector has not identified a comprehensive program aimed specifically at reducing the potential for human error. Individual managers have attempted to improve the attentiveness of persons under their direction.

(Open) 155/85007-01, Component Identification. The licensee responded by letter to Region III dated August 2, 1985, to concerns over component identification. The response is reviewed in section 3 of this report. The item remains open pending review of the licensee's proposed program for component identification. The inspector reviewed the program developed by a Shift Supervisor to replace handwritten labeling, label major components, and evaluate the need to identify fluid and flow direction in piping systems and found it to be particularly thorough. At the close of the inspection period the study was not complete.

(Closed) 155/84007-01, Procedural Inadequacies on Control Room Alarms Related to Radwaste Processing Area. The inspector reviewed the alarm procedure containing actions to be taken when the remote radwaste alarm in the control room annunciates. The procedure states that someone must be sent to the radwaste area to determine from the local alarm panel what caused the common alarm to annunciate. If the local alarm indicates high level in one of the dirty waste receiver tanks, the procedure states that the tank should be isolated. The operator informed the inspector that the licensee has reemphasized this procedure to all operators.

3. 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 tag-out 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.

a. The inspector observed licensee preparations for shipping spent resins offsite. A special radiological control zone was set up and roped off. Radiation tags with dose rates were posted around the perimeter of the zone and actual operations were under the surveillance of a radiation protection technician. The technician was aware of appropriate procedures and had an updated copy of the pertinent one in his possession. He occasionally monitored the area around the outside of the shipping cask and when asked by the inspector knew at what radiation levels filling would have to cease. Workers inside the controlled area were wearing appropriate anticontamination clothing.

On August 19 the inspector observed the licensee's shipment of dewatered resin for burial disposal. The shipment consisted of one high integrity container with an estimated 195 cubic feet of spent resins. On August 21 the inspector observed the licensee's shipment of contaminated resin pumping equipment being returned to the resin disposal contractor. Both shipments were conducted in accordance with procedural requirements.

b. On August 22 the licensee performed weekly Surveillance Test T7-28, "Diesel Generator Auto Start and Run." The emergency diesel generator (EDG) started but the output breaker failed to close. The problem was traced to the EDG rheostat controlling output voltage which had been mispositioned apparently as a result of being bumped while Appendix R modifications were in progress in the EDG room immediately adjacent to the rheostat. The lowered rheostat setting resulted in a generator output of 390 V. When the voltage was increased using the rheostat to the normal output 480V the breaker closed. The test was repeated successfully. The licensee, prior to resumption of construction activities in the EDG room, installed a temporary guard over the rheostat and inspected the area to identify other controls that were vulnerable to work in the area. No other controls were identified or precautions taken. Long term corrective actions are being evaluated.

On August 19 the licensee removed from service the 46KV line power source for maintenance of the 7726 breaker. The 46KV line was unavailable for approximately three and one-half hours. Since construction activities had been ongoing in the EDG room continuously since the last previous successful performance of weekly surveillance T7-28 on August 15, it is possible that the 46KV line was removed from service while the EDG was unavailable due to the reduced rheostat setting. Technical Specifications 11.3.5.3 require both the EDG and the 46KV line, but permit one or the other to be out of service for up to three days. If both are out of service, reactor shutdown is required. The inspector expressed his concern to the licensee that a potential Technical Specification violation existed of which they were unaware and that the licensee did not adequately inspect the area where construction activities were to take place prior to commencement of work to identify the potential impact of the activity on equipment important to plant safety and relate those interface areas to the contractor performing the work. Further, prior to removal of the 46KV line from service, the licensee did not perform testing to verify the operability of the EDG, nor did they evaluate the need for such an operability verification. Such an evaluation is not required by procedures. The licensee committed to evaluate the need for a generic requirement to verify the operability of a required backup system or component prior to removing from service a component required by Technical Specifications. That evaluation will be tracked as an open item (50-155/85014-01(DRP)).

c. On August 22 the licensee conducted a fire drill involving the Charlevoix Fire Department. The drill was conducted as part of a licensee audit for fire control activities at the facility. During the week of August 26 the licensee completed hands-on training for all site personnel.

d. In reviewing one of the shift supervisor log books, the inspector noted an instance where a surveillance test could not be completed because of an apparently inoperable piece of measuring equipment. The next day's entry on the same subject indicated the test had been completed, but there was no indication of what caused the measuring equipment to malfunction, if it was repaired, or if other equipment was used to complete the test. The shift supervisor and other personnel also were uncertain as to the test measuring equipment used to complete the test. Further inquires by the inspector determined the cause of the initial failure to be improper use of the equipment. The inspector stated his concerns to the licensee that log books generally do not contain sufficient information to document operations. The licensee stated this also has been a concern to them and that this will be reemphasized to operations personnel.

e. On August 24 the inspector observed portions of the performance of Surveillance T365-12 which inspected site fire hydrants prior to onset of cold weather.

f. On August 26 the inspector observed three crates marked "contaminated materials" sitting adjacent to but outside the roped contaminated material storage area in the turbine laydown area. This was the second instance of this situation in several weeks. The licensee relocated the boxes within a properly segregated area.

g. On August 27 the inspector observed that work activity was being performed in an area adjacent to the sphere ventilation ducts penetrations which was marked with tape on the floor and rope to define a boundary and a sign indicating the area was contaminated. The inspector pointed out that there was no radiological posting specifying dose, contamination levels, or clothing requirements for access. The licensee established a posting for the area.

h. On September 4 the inspector observed preoutage testing of the reactor vessel stud pretensioning machine.

i. During the week of September 23 the inspector observed control rod blade and channel shuffling within the reactor vessel.

j. During the period October 14-16 the inspector observed preparation for fuel loading, including the requirements of TR-46, Fuel Bundle Core Loading Procedure and Standard Operating Procedure (SOP) 2, Refueling Operations. The inspector reviewed checksheets to verify system operability and containment integrity, verified that nuclear instrumentation and portable submersible fission chambers were available, and that restrictions on personnel access were in place.

On October 16 the inspector observed from the reactor deck and the control room the commencement of fuel load, confirming the availability of adequate communications between the reactor deck and the control room and the adequacy of unbreakable covers on underwater lights. The inspector verified the operability of the crane and the availability of radiation monitoring instruments on the crane and reactor deck, including airborne monitoring. The inspector noted that aside from the surveillance on area radiation monitors installed on the refuel deck, which are relied on as criticality monitors during fuel loading, the shift supervisor who signed verifying the availability of two criticality area monitors had not determined their operability immediately prior to commencement of fuel load. The monthly surveillance had last been performed on September 25. Operating personnel informed the inspector that based on the surveillance it was safe to "assume" the monitor was fully functional. The inspector later determined that a meter face on the refuel deck monitor allows the operator to perform comparison checks using portable radiation detection instrumentation.

k. On October 23 the inspector brought to the attention of the licensee's security force a crew of contractor workers digging a ditch adjacent to the perimeter security fence on the interior of the protected area without being accompanied by a security officer. Licensee procedures call for a security officer to monitor all digging adjacent to the perimeter fence with the intent of preventing potential unauthorized personnel from concealing themselves within the excavated area or behind mounds of dirt. A review by the inspector determined that the contractor performing the work was aware of the requirement to have security coverage during excavation but failed to request that coverage. The incident offers no threat to the physical security of the facility. The inspector did express concern that the security officers monitoring television surveillance cameras from two separate alarm stations did not identify digging activities adjacent to the fence. The licensee reviewed the requirements with the contractor and issued a memorandum to plant staff summarizing those situations which require support from site security.

l. During the inspection period the inspector discussed with the licensee changes to Refueling Test TR-46, Fuel Bundle Core Loading Procedure, involving reduced frequency of shutdown margin (SDM) checks during fuel bundle loading. During previous major refueling bundle loading, SDM calculations were performed after each bundle placement and involved full withdrawal of a control rod of highest worth and withdraw to notch Number 6 of an adjacent control rod. The criteria for acceptance was that the core remain shutdown by at least 0.3% reactivity. Subcriticality checks, involving the full withdrawal of one control rod in the vicinity of the newly placed bundle, are now performed after each bundle placement and SDM checks are performed at four times during core load. These checks are performed at the most reactive positions during core loading and after core loading operations are complete. Also, rather than pulling the adjacent rod directly to notch number 6 the rod was pulled to a predetermined position calculated to add 0.3% reactivity. This is consistent with the requirements of Technical Specifications 5.2.5. The licensee revised TR-46 after calculations identified the possibility that a SDM check that pulled the adjacent rod directly to notch 6 might cause a criticality not expected by the operator. This calculation considers the net gain in core reactivity resulting from this cycles' core loading configuration and the calculated depletion of control rod worth.

m. During the inspection period the inspector reviewed the licensee's letter dated August 2, 1985, submitted to Region III in response to concerns identified in Inspection Report 50-155/85007(DRP). Licensee actions to address instances of mispositioned control rods appear to adequately address potential administrative approaches to this recurring incident. The licensee recognizes that operator inattentiveness is the root cause of this type of event. The design of the facility does not provide any engineered systems to impose rod movement restrictions to reduce the potential for human error. The inspector expressed his concern to the licensee that the minor administrative changes committed to in their response will not significantly reduce the likelihood of this type of event occurring again, and that since rod position is totally a function of human control over the rod control system any real results can come only from programs designed to upgrade operator skills and provide motivation for operators to pay sufficient attention to rod movement.

The second concern addressed the licensee's program for component identification and included a discussion of the events detailed in Inspection Report 85007 and actions taken in previous years to identify plant components. The inspector concluded that the licensee's proposed program should bring about limited improvement in component identification, but simply does not go far enough to provide any assurances that the type of event described in Report 85007 and those which contribute to the violations presented in this report will be prevented. The inspector presented his view that the only point in the licensee's proposed program which offers the potential for real improvements in reducing the risk of equipment identification errors is the project to photograph high radiation areas to aid in pre-job planning. A program of that type, developed in sufficient detail and conscientiously utilized by operators, could have prevented the misidentification of VRD-305 discussed elsewhere in this section. No other point of the licensee's proposed program would be expected to make any contribution toward reducing human error. A tagging program being developed by a Shift Supervisor and supported by the licensee is activity that is beyond the commitments presented in the response and has the potential to make marked improvements in component identification. The inspector summarized his position to the licensee that this type of event can be expected to continue to occur until a component identification program of the depth suggested in section 3.k of Inspection Report 85007 is fully implemented and Operations personnel exercise more rigorous and thorough control over activities requiring components to be positively and accurately identified.

The inspector's concern over the increasing frequency of events which have as a contributing or root cause human error or inattentiveness, including several new examples contained in this report, continue to be the subject of Unresolved Item (155/85007-02).

n. Effective August 1, 1985, the licensee reorganized the Big Rock Point Plant Staff with the objectives of reducing layers of supervision, emphasizing plant performance, improving communication between Engineering and Maintenance , and centralizing procurement planning functions. The new organization replaces the former Operations and Maintenance Superintendent with the Production and Plant Performance Superintendent reporting to the Plant Superintendent. Included in this new department are the Operations, Reactor Engineering and Plant Performance functions. The Maintenance Superintendent now reports directly to the Plant Superintendent and includes both Maintenance and the Engineering department functions formerly assigned to the Technical Department, which has been eliminated. A newly created Planning and Administrative Services Superintendent directs the Technical Review Group and Living Schedule Activities, as well as Property Protection, Outage Coordination, administrative services, and procurement functions. The Chemistry/Health Physics, Human Resources, and Public Affairs departments and the Technical Engineer, remain unaffected by the reorganization. The licensee has submitted a change to Technical Specifications section 6.2. The reorganization does not involve any new personnel at the Superintendent level and is not a safety issue. However, the inspector pointed out that since changes to the site organization requires Technical Specification changes approved by NRR, the reorganization implementation date should have been delayed until after approval was granted.

o. On September 24 the licensee was notified by the Charlevoix County Sheriff's Department of tornado sightings in the general area of the facility. During the tornado warning the licensee suspended all work on the refueling deck, including rebuilding of fuel bundles by vendor technicians. No fuel was in the reactor. The ability of the Shift Supervisor to protect the plant from the effects of unpredicted developments in the weather was hampered by the absence of a radio in the Shift Supervisor's Office. During the unexpected and rapidly developing weather system that resulted in warnings from local governmental officials to take cover, the community relied on local radio for storm status and emergency instructions.

p. During the inspection period the licensee completed construction of the Alternate Shutdown System (ASD) designed to meet the requirements of 10 CFR 50, Appendix R, for remote shutdown capability. The licensee's design provides the ability to operate the Main Steam Isolation Valve (MSIV), Emergency Condenser Isolation Valves and Control Rod Drive Pump No. 1 from a remote area apart from containment or the control room. This is intended to provide remote shutdown capability in the event fire in the control room, electrical equipment room, or inner or outer cable penetration areas made normal control room operation of equipment required to shut down the facility impossible. Power to operate DC operated valves is supplied from the ASD battery, while power to operate AC powered components is supplied through switches directly from the output of emergency diesel generator (EDG). Technical Specifications necessary for system operation were submitted to NRR. While approved Technical Specifications are not required prior to startup, the licensee in their submittal committed to operate the system in accordance with the proposed Technical Specifications.

q. On October 1 the licensee changed their emergency communications procedures to notify the Michigan State Police in Lansing instead of the local State Police post in Petoskey. One red phone located in the Technical Support Center (TSC) is equipped with an automatic dialer to contact the State Police in Lansing and the Charlevoix County Sheriff's Office. The Petoskey post remains as a backup contact. The licensee changed Emergency Notification procedure EPIP 6F to reflect the change. The fifteen minute limit for notification from the time an emergency classification (unusual event or higher) is declared, remains.

r. During the inspection period the licensee completed conversion from the Bio-Pak to the Scott Air Pak. Back up bottles are stored in the turbine building and a temporary cascade system for bottle refill is in use until final installation of a cascade system near the control room is complete.

s. During the period October 22-27 the inspector observed licensee's performance of the Containment Integrated Leak Rate Test (ILRT). This test is conducted to demonstrate the ability to isolate all containment sphere penetrations with a high degree of leak-free integrity, thereby demonstrating that all leakage from a loss of coolant accident would be contained within the sphere. The facility successfully completed the ILRT on October 27. Detailed results are presented in Inspection Report 50-155/85020 (DRS) prepared by a Region III specialist who observed the entire test.

t. During the refueling outage period the inspector observed several instances of contaminated shoes and clothing. The inspector observed two examples of licensee's efforts to keep housekeeping and safety under control, specifically a special clean-up and a written message to all personnel in the plant Bulletin. The licensee ALARA coordinator identified to the facility management problems with contamination control in general, particularly on the reactor deck. The coordinator conducted a survey of the reactor deck that confirmed high levels of contamination on various components in the area. He recommended a more formal survey and decontamination program which emphasizes immediate decontamination of identified areas by personnel whose activities are restricted to decontamination work. The inspector supports the recommendations of the licensee ALARA coordinator. The licensee has committed to evaluate the recommendations for implementation during the next refueling outage.

u. On October 1, the licensee made a presentation to Region III management in Glen Ellyn that addressed the issues raised in Inspection Reports 50-155/85010(DRS) and 50-155/85011(DRP). Subjects included maintenance issues and activities, current plant licensing activities, quality performance, trends, and objectives, and recent revision to the Nuclear Operations Department Standards (NODS) and Quality Assurance Requirements Matrix (QARM). The Plant Superintendent discussed recent changes to the Big Rock Point staff organization discussed elsewhere in this report.

v. On September 10 a traveling crew Maintenance Supervisor (MS) received the appropriate work authorization to repack the steam isolation valve to the steam seal regulator and air ejector, CV4104. A repairman was assigned to the job, which requires scaffolding to reach. Due to problems with protective clothing the repairman was unable to complete the work and the MS assigned the work to a second repairman with an explanation of the nature of the job and the location of the valve relative to the scaffolding that had been erected. A delay of 24 hours elapsed between the work of the first repairman and the time the second repairman commenced work. During that period the scaffolding located at CV4104 for the first repairman had been moved to a location at the turbine bypass warming valve, CV4106. Although the valve is conspicuously identified on one side, the scaffolding was situated to provide access from the backside where no identification is displayed. The repairman disassembled and repacked CV4106, the wrong valve for which he had no maintenance order or working authorization. By fortunate coincidence, the isolation for CV4104 also provided isolation for CV4106, thereby averting possible personal injury and damage to the plant.

Technical Specification 6.8.1 requires that "written procedures shall be established, implemented and maintained for all structures, systems, and safety actions defined in the Big Rock Point Quality List. These procedures shall meet or exceed the requirements of ANSI N18.7, as endorsed by CPC-2A." This requirement is implemented in Big Rock Point Local Control Procedures.

Local Control Procedure, Part 1, for tagging, place responsibility on the person-in-charge (MS) to verify the "physical position of valves which provides workman protection" and to have a "complete understanding of the limitations of his working clearance, the condition of the equipment involved and that the...mechanically isolated and protective tagged equipment encompasses the work area needed, thereby making the equipment safe to work on." Further, the repairman has the responsibility of determining that the equipment being worked on is depressurized and deenergized as necessary to perform the work. The failure of the MS to provide the proper direction to the repairman working under his clearance and to positively verify the valve to be disassembled was mechanically isolated and tagged and thus safe to work on, combined with the failure of the repairman to verify the valve was in condition to be worked on is contrary to Local Control Procedure, Part 1, and is a violation (155/85014-02(DRP)).

w. On September 25 an incident occurred in the recirculation pump room in which a repairman from a traveling maintenance crew opened a check valve not within the tagged isolation boundary, resulting in a direct drain path from the reactor vessel. The water was drained from the reactor vessel, which contained no fuel, when the repairman disassembled control rod drive system check valve VRD-305. The repairman thought he was working on liquid poison system check valve VP-301. The valves are located about six feet apart at the same elevation. The chronology leading up to the event is as follows:

On September 20 the control room operators established tagging isolation for the traveling crew maintenance supervisor (MS) to disassemble, inspect, and reassemble VP301 using Procedure TR-74, Inspection of Liquid Poison Supply Check Valves VP-301 and VP-302. Operators tagged three valves to isolate VP-301.

On September 23 the MS and Auxiliary Operator (AO) entered the containment sphere for the purpose of tagging verification as a prerequisite to issuing working clearance to the MS for the work to be performed. Entering the recirculation pump room they were joined by a radiation protection technician (this technician was a temporary contractor employee, not a permanent Big Rock Point employee). The request by the MS for the AO to positively identify VP-301 created some confusion. The AO did not know which valve was VP-301 and sought assistance from the control room operator via the telephone from the recirculation pump room area. The valves involved in this incident were not marked for component identification. The control room operator referred to the system drawing and related to the AO the location of VP-301 relative to other valves in the system. No other operator entered the pump room to attempt to resolve the confusion. The Shift Supervisor was not consulted. Despite his continued uncertainty, the AO issued working clearance to the MS, thus authorizing him to have his repairmen disassemble a valve he could not positively locate. The AO reportedly believed the problem of positive identification would be resolved later. The MS informed the inspector that upon returning from the telephone the AO positively identified VRD-305 as the valve to be worked. This is one of several conflicting statements associated with the events that took place.

On September 24 workmen assigned to repair VP-301 surveyed the area for pre-job planning, entering the pump room with the radiation protection technician who had accompanied the MS and AO the previous day. The technician identified incorrectly VRD-305 as the VP-301 valve to be disassembled, but because of a problem with gaskets the valve was not disassembled at that time. The technician who identified the valve to the assigned workman is not a licensed operator. The workmen did not review their working clearance with the MS.

Later, on September 24 the MS requested a tag be hung on VP-301 for positive identification. The Shift Supervisor (SS) fabricated an identification tag for VP-301. The licensee later verified the tag had been hung on the correct valve.

On September 25 the repairmen, accompanied by a radiation protection technician commenced disassembly of VRD-305, thinking they were working on VP-301. The MS informed the inspector that he did not reenter the room with his workmen, but requested the technician to identify the valve for the repairmen. Neither repairman nor the technician were aware the ID tag had been hung on VP-301. When the valve's cover and valve guide were removed the pressure associated with the water in the reactor vessel blew out the valve's internals and water flowed six feet into the air. The repairmen and technician notified a second technician of the situation. The second technician, more aware of the urgency of the situation, notified the control room. The failure of the parties involved to notify the control room promptly and directly resulted in an estimated 35 minute delay in locating and isolating the leak. The licensee calculated that the refueling shield tank level, installed above the reactor vessel during refueling operations, fell approximately two feet. That level drop would indicate an estimated 1400 gallons was lost from the vessel to the pump room. The room has a drain sump to the liquid radwaste system.

Technical Specification 6.8.1 requires that "written procedures shall be established, implemented and maintained for all structures, systems, and safety actions defined in the Big Rock Point Quality List. These procedures shall meet or exceed the requirements of ANSI N18.7, as endorsed by CPC-2A." This requirement is implemented in Big Rock Point Local Control Procedures.

The inspector identified the following areas of concern:

(1) A comprehensive tagging program that identified all components and marked pipes for contents and flow direction would have prevented this incident. The lack of

component identification in the plant, when combined with increasing numbers of younger operators with relatively fewer years of operating experience on this plant, creates the likelihood that this type of incident will continue to occur. The inspector's concerns over this issue are presented elsewhere in this report and in Inspection Report 50-155/85007(DRP).

(2) The AO who granted clearance to the MS while being unable to identify the component for which clearance was issued was derelict in his duties to operate the plant safely and responsibly. The AO acts as a delegate of the Shift Supervisor when he uses his signature on the tagging order to issue working clearance to a person in charge. Local Control Procedures that control tagging require that "if at any time there is not complete understanding and agreement of what is to be done, stop and resolve the misunderstanding or disagreement before continuing." Local Control Procedures, Part 1, that directs issuance of working clearances also states that "after equipment is removed from service, the Operations Supervisor, using the original switching order and accompanied only by the person(s) in charge, not his delegate, shall double-check the working clearance protective tagging point(s). He shall identify what equipment has been electrically de-energized and/or mechanically isolated, check off each step on the switching order, point out the limits of working clearance and call attention to adjacent energized, operating or available equipment." The AO's failure to positively identify valve VP-301 to the MS and his issuance of work authorization is a violation of Local Control Procedure, Part 1 (155/85014-03(DRP)).

(3) The MS, as the person in charge, failed to positively identify to repairmen performing work under his clearance the correct component. Recognizing the potential for confusion, the MS relied on a radiation protection technician to identify to his repairman the valve to be worked . Local tagging procedures require the person in charge have an "understanding of the limitations of his working clearance, the condition of equipment involved and that the electrically de-energized and/or mechanically isolated and protective tagged equipment encompasses the work area needed, thereby making the equipment safe to work on." While the MS did identify the need to put a component identification tag on VP-301, he did not follow through by instructing his repairmen to look for the tag or by personally directing his workmen to the valve. Despite the conflictive statements of the MS and the AO concerning positive identification of the valve, the inspector finds reason to believe that sufficient confusion existed to make it impossible for the MS to positively verify the physical position of valves to

isolate the valve incorrectly identified as VP-301. Failure to verify the condition of the equipment involved and that the equipment was mechanically isolated and protective tagged, thereby insuring the valve was safe to work on, as required by Local Control Procedure, Part 1, is a violation (155/85014-04(DRP)).

(4) The technician who identified to the workmen the incorrect valve was performing the duties of an operator, a function for which he was not qualified or trained. Local tagging procedures (Local Control Procedure, Part 1) require the Shift Supervisor to take responsibility for "identification of what equipment has been electrically de-engerized or mechanically isolated." The procedures permit delegation of this authority. The authority was not delegated to the technician, and the act of a maintenance supervisor in permitting the technician to exercise this authority is a violation (155/55014-05(DRP)).

(5) Local tagging procedures (Local Control Procedure, Part 1) require that the repairman, after clearance is issued but prior to starting work, take personal responsibility for ensuring the equipment is depressurized and de-energized as necessary to perform the work. In addition, Big Rock Administrative Procedure Volume I, Chapter 5, Maintenance Department Administration, requires in section 1.5.6.4.2.C that Maintenance Procedures contain verification "by the repairman responsible for the task to ensure that it is safe to work on the equipment." Maintenance procedure TR-74 to disassemble VP-301 has a certification signed off by the MS that VP-301 is isolated from the reactor vessel with proper tagging performed. The VRD-305 was outside the tagged isolation. Failure to verify the valve was isolated and depressurized, as required by the above procedures, is a violation (155/85014-06(DRP)).

(6) The failure of the repairmen or technician to promptly report the urgent situation in the pump room to the control room could have resulted in a serious hazard had the reactor core been in the vessel and the vessel drained to expose the fuel. Provided the Core Spray System is available, drainage from the reactor vessel would be offset by makeup from that system, which is automatically activated when reactor level drops to 2'9" above the top of the active fuel. However, since Technical Specifications require Core Spray operability only during power operation and refueling operations, there are periods during outages when Core Spray may be removed from service. Refueling operation is defined as any operation with vessel closures open during which a core alteration, or other operation which might affect core reactivity, is in progress. An incident of this type, with fuel in the

reactor but no core alterations taking place and Core Spray unavailable, would likely result in the fuel being uncovered. The failure to notify management of an emergency situation is the most blatant example in the series of events caused by individuals who failed to exercise personal responsibility for their own actions and for plant safety.

The inspector discussed with the licensee several instances in the recent months where contractors or licensee personnel not normally assigned to the Big Rock staff were involved in incidents involving work performed on the wrong component. Two examples are presented in this report, while other examples are found in section 3 of Inspection Report 50-155/85007(DRP). The inspector specifically addressed the question of adequate control over the activities of travel crews and contractors. The licensee maintains that they continue to expect travel crews and contractors to play an important role in repair activities and expects the workers and managers of those crews to assume responsibility for the quality of their own work in accordance with the requirements of the plant. The licensee indicated that based on the difficulties experienced during this outage they intend to review their overall approach to outage management. The inspector pointed out his observation that many contractors and travel crew workers required additional guidance and training in Big Rock requirements and in positive location of the component to be worked on. The licensee indicated that greater control over tagging procedures and isolations was a priority objective.

Related to the event involving VRD-305 is an example of the need to adhere to tagging and isolation procedures. Early on September 25 a different travel crew Maintenance Supervisor not involved with the identification of VP-301 determined that Liquid Poison System Check Valve VP-302 was located within the isolation established for VP-301 on September 20. The Supervisor positively identified VP-302 by its identification tag and verified it inside the recirculation pump room. The Shift Supervisor, contrary to Local Control Procedure, Part 1, did not issue a new tagging order, but altered the tagging order for VP-301 by adding "and VP-302" to the September 20 tag order. (The Local Control Procedure required that a Switching and Tagging Order "shall be filled out for each tagging and switching operation ordered by the Opertions Supervisor. . ." Local Control Procedures also state that "when working clearance protective tagging points are identical, more than one person in charge may receive working clearance simultaneously." Local Control Procedures further state that "the person-in-charge is the <u>only</u> person for whom protective tags are placed). This has personnel safety consideration since the MS (person-in-charge) with clearance on VP-301 was not aware other work on VP-302 was being performed by a separate crew using his authorization. Had the first MS completed his work on VP-301 without incident and released his authorization, the second MS would have found himself working without a tagged clearance to insure isolation on a check valve with the ability to drain the reactor vessel. Local tagging procedures provide a means by which a second work crew supervisor can obtain clearance through the original MS's clearance. The paper work is processed in such a way as to provide written addendums to the original documents that establishes the additional work is being performed with the full approval of the original person in charge and the Shift Supervisor. Failure of the Shift Supervisor to issue a new switching order for work on VP-302 and instead modifying the existing order for VP-301, combined with the action of the Maintenance Supervisor to allow his repairman to work under the clearance of another Maintenance Supervisor who was unaware of that work, is contrary to Local Control Procedure, Part 1, and is a violation (155/85014-07(DRP)).

The licensee identified deficiencies in the TR-74 procedures used to perform inspections of VP-301 and VP-302, including a missing page that contained a cross sectional drawing that could have alerted the repairmen to the fact that VRD-305 being disassembled in no way resembled VP-301. The licensee identified that the Shift Supervisor (SS) improperly eliminated an initial condition requirement for core spray availability, which was not required from an operational consideration because no fuel was in the vessel, by simply making "N/A" for "not applicable." The proper method to make this type of modification is via a formal temporary change to the procedure.

Each of the TR-74 procedures for repair of VP-301 and VP-302 include sections documenting the return to service prior to operability and a signature on the cover sheet attesting to component functional operability. In each case the procedure was incomplete in that the return to service section and the review section was not signed off. However, each procedure was signed on the cover sheet certifying component functional operability. The cover sheet signature on TR-74 for VP-301 was subsequently removed using white out. Big Rock Administrative Procedures, Volume I, Chapter 5, section 1.5.6.4.2 requires that maintenance procedures contain requirements for returning the component to service prior to operability and to ensure proper review and close out of the procedure. Section 1.5.6.2.B.2 of the procedure requires maintenance procedures be used for maintenance work on a Q-listed component, which would include VP-301. Failure to perform the required work activities to complete sections 5 and 6 of TR-74 for VP-302 is a violation (155/85014-08(DRP)).

4. <u>Monthly Maintenance Observation</u>

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 August 22 the inspector observed repairs to fuel channels damaged during the 1983 refueling.

b. During the week of September 23 the inspector observed the replacement of the Barton containment level transmitter, LT-3175. The transmitter exhibited sluggish behavior during calibrations and indicated lower than actual level. Transmitter LT-3175 was replaced with the spare transmitter and successfully calibrated. Previous maintenance activity related to transmitter repairs or replacement is documented in section 3 of Inspection Report 50-155/84017(DRP).

   During the inspection period containment level transmitter LT-3171 was replaced by a new Qualified Barton transmitter. A spare is on site for LT-3171, but not for LT-3175.

c. During the week of September 23 the inspector observed the overhaul of Control Rod Drive Pump number 1.

d. On September 24 and 25 the inspector observed fuel bundle rebuilding activities conducted underwater in the spent fuel pool by fuel vendor representatives. The purpose of the fuel pin removal activity was to identify and replace leaking fuel pins first identified as failed in November, 1984. Three bundles were repaired and returned to the core. The vendor was unable to locate the leaking pin in a fourth bundle which was not returned to the core. A fifth leaking bundle had reached the end of its useful life and was stored in the spent fuel pool.

e. On September 24 and 26 the inspector observed a contractor perform dye penetrant testing on internal components of the steam drum safety relief valves. Certain internals were replaced as a result of the inspection.

f. During the inspection period the inspector observed the rebuilding of the pump rotor assembly to be installed in Number 2 feed pump during the 1985 outage. The rotating assembly was rebuilt using a written procedure.

g. During the inspection period the inspector observed portions of the Inservice Inspection (ISI) program and inspections conducted by qualified contractor inspectors to identify intergranular stress corrosion cracking (IGSCC) in stainless steel recirculation piping. No IGSCC defects were identified. The ISI/IGSCC program was the subject of a special inspection by a Region III specialist, and Inspection Report 50-155/85018 (DRS).

h. During the inspection period the inspector observed portions of the removal of the "C" Target Rock Depressurization Valve. The valve was shipped to a contractor facility for repair and bench testing.

i. During the inspection period the licensee completed final environmental qualification of electrical equipment (EEQ) as required by 10 CFR 50.49. At the close of the inspection period several functional tests remained that certify correct electrical wiring configurations, all to be completed prior to criticality. The inspector will review the completed modification during a future inspection.

j. During the inspection period the licensee conducted tests and inspection on the emergency condenser in search of a small primary to secondary leak across tube bundle No. 2. Discovery of the leak on May 24 and subsequent operation of the condenser through the completion of the cycle is detailed in section 3.a of Inspection Report No. 50-155/85011(DRP). The licensee hydrostatically tested the tube bundle to 1450 psig minimum, or approximately 109% of normal operating pressure with negative results. The licensee used contractor personnel to perform helium leak testing capable of detecting changes in helium concentration of 1 ppm. Helium testing identified no leakage. The licensee conducted eddy current testing, which did not identify leaking bundles in the emergency condenser. No tubes required plugging due to tube degradation. Finally, dye penetrant testing was performed on the condenser waterbox tube to tube sheet welds with no indications identified. Two potential explanations were not explored by the licensee. First, the gasketed joint between the condenser and tube sheet was not tested or disassembled for inspection. Second, the tests were conducted cold, while at power the tubes and tube sheet are warmed slightly, although not to normal plant operating temperatures.

The Plant Review Committee (PRC) reviewed the inspection results and concluded that because the leak had not been located the tube bundle must be fully operable and leak free. The PRC recommended restoration of the emergency condenser to fully operable status and implementation of expanded sampling program. The inspector expressed his view that a leak which affected operability prior to shutdown but which could not be identified through exhaustive testing methods does not logically imply that there is no leak, but rather that it simply has not been located. The inspector's review supports the licensee's position that the unit should start up with both loops available for service in their normal configuration, thus permitting continued sampling and analysis. The very small size of the leak prior to shutdown, which was well below regulatory limits, makes the hazard to the public health and safety minimal. The inspector discussed with the licensee the restrictions of Technical Specifications 4.1.2 (b) which permits operation with one tube bundle leak that develops during power operations, but requires both tube bundles be available for service during heat up for power production. Start up with a known leaking tube bundle would be in violation of Technical Specifications. The inspector encouraged the licensee to request concurrence from NRR to permit startup. The licensee's PRC specified an initial sample at 48 hours, a weekly sampling program, guidance for operators and supervisors should a leak be detected, and an evaluation by the Chemistry/Health Physics Superintendent to ensure regulatory threshold limits are not violated.

5. Licensing Activities

By letter dated August 26 the Commission issued Amendment No. 77 to Facility Operating License DPR-6. This amendment includes additions to the Technical Specifications to incorporate the Radiological Effluent Technical Specifications (RETS) to meet the requirements of 10 CFR 50, Appendix I. The staff review included approval of the proposed Offsite Dose Calculation Manual (ODCM) and Process Control Program (PCP).

By letter dated October 9, the licensee withdrew a change to Technical Specifications dated November 1, 1984, that would require calibration of portable high range gamma measuring instruments on all scales every six months. Because the licensee's decision to retain the existing three month calibration frequency is more conservative than the six month frequency proposed in the change request, the inspector concluded that the licensee's action had no impact on their commitments made as a result of a violation in Inspection Report No. 50-155/84012(DRSS) which addressed the calibration frequency issue.

By letter dated October 2 the staff granted Amendment No. 78, Definition of Operability.

By letter dated October 22 the Commission granted Amendment No. 79 to Technical Specifications, defining surveillance frequencies.

6. 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.

(Closed) LER 85-006, Partial Loss of Offsite Communication. This LER was submitted by the licensee to document a partial loss of offsite communications caused by a cable accidentally severed by telephone company workers. The event was reported in section 3.f of report No. 50-155/85011.

7. **Headquarter Requests**

At the request of NRR the inspector conducted a review of the licensee's proposed Technical Specifications addressing the newly installed Alternate Shutdown (ASD) System. The inspector conveyed the following comments to NRR and the licensee.

a. Surveillance tests to verify operability of system components which were proposed at 18 months should be modified to read "prior to startup from a major refueling outage, but not less often than every 18 months." This would make the submittal consistent with the surveillance frequency requirements of Amendment No. 79 to Technical Specifications. The inspector expressed concern that work performed during a major refueling outage which adversely affected the ability of the ASD system to perform its safety function would not necessarily be discovered until well into the next cycle. Requiring the tests prior to startup implies that the facility would begin the cycle with reasonable assurance that the ASD system would function as expected.

b. The licensee's submittal did not address equipment necessary to take the plant from hot shutdown (with conditions ranging from normal operating pressure of approximately 1335 PSIG down to atmospheric pressure at 212 degrees F) as required within 72 hours by 10 CFR 50, Appendix R, section L.1.(d) and (e). The licensee's design uses temporary cable using the Emergency Diesel Generator (EDG) as a power source. Lacking operability requirements for this equipment to achieve cold shutdown, the inspector recommended a separate surveillance to verify the availability of all cables and equipment to operate these pumps if required.

c. The licensee proposes an operability requirement on Control Rod Drive (CRD) Pump No. 1 that would permit it to be out of service for up to sixty days before the plant would have to suspend operations. The licensee selected sixty days based on the draft Technical Specifications guidance provided by NRR, and informed the licensee that there was no other engineering justifications for that choice. The inspector learned from the staff of NRR that the sixty day figure was arbitrarily established and was not derived from any formal evaluation for the Big Rock plant or any other specific facility. The inspector objected to the sixty day figure as being excessively long. The concern stems from the facility's design which provides the ability to inject makeup into the reactor at high pressures only with the CRD pump. The plant has no high pressure coolant injection or core isolation cooling systems comparable to those found in modern plants. Unavailability of the CRD pump would mean the plant would be unable to provide makeup water into the reactor until pressure had dropped to approximately

120-150 psig, within the capability of the core spray system to inject water. Licensee calculations indicate that the top of the fuel would not be uncovered as the primary coolant inventory gradually cooled and shrank in volume by circulation through the emergency condenser. The licensee, unable to predict whether control circuitry for valves in the core spray flow path would be available to open the valves, or whether containment would be accessible, intends to rely on manual operation of the valves from within containment. Assuming the valves accessibility, this would require inhibiting the Reactor Depressurization System (RDS) as a personnel safety consideration. Contrary to the licensee's submittal statement that RDS inhibition is consistent with Technical Specification 3.15 (RDS Operability), any disabling of RDS in any plant condition above cold shutdown would be a direct violation of Technical Specifications. The CRD pump is the only dependable source of makeup water to the reactor at any pressure. The inspector, based on machinery histories and interviews with Maintenance and Operations supervisors determined that a typical complete overhaul can be accomplished in three days and that currently required preventive maintenance can normally be completed in one shift. Those interviewed recalled one instance where physical damage to a pump component rendered it out of service for approximately one week while parts were in shipment. On this basis the inspector recommended an operability requirement of fourteen days. The licensee resisted this suggestion on the grounds of reduced operational flexibility. The inspector proposed as an alternative including the No. 2 CRD pump in the design with the installation of power source transfer switches that could power CRD pump No. 2 with the ASD power supply now reserved for CRD pump No. 1. The licensee indicated they would keep the submittal at sixty days and agreed to perform a formal cost/benefit analysis by the Probabilistic Risk Assessment Group to determine the feasibility of extending power availability to CRD pump No. 2. The inspector requested that the study emphasize safety and wait to establish its cost/benefit characteristics until after the more important safety considerations are addressed. The licensee is tracking the item on an Action Item Request and has established a target completion date of March 1, 1986. The item will be tracked as an open item (50-155/85014-08(DRP)).

d. The licensee's original submittal addressed only power to components and did not address the operability of the component itself. This oversight was to be corrected by the licensee.

8. <u>TMI Action Items</u>

a. <u>II.B.1.3, Reactor Coolant System Vents</u> - By letter of July 17, 1985, the Office of Nuclear Reactor Regulation informed the licensee that high point vents were not needed for Big Rock Point and granted the licensee an exemption from this requirement. This item therefore is closed.

b. II.F.2.3, Instrumentation to Detect Inadequate Core Cooling - This item is discussed in the Big Rock Point Integrated Plant Safety Assessment Report (IPSAR) under section 5.3.19. The NRC has determined that the licensee should be exempted from this requirement and will document this exemption by letter with a projected completion date of December 31, 1985.

9. Enforcement Conference

Subsequent to the end of the inspection period, Consumers Power Company and NRC officials met in Glen Ellyn, Illinois, on December 5, 1985, to discuss the series of violations contained in this report. Consumers Power Company was represented by Mr. R. DeWitt, Vice-President, Nuclear; Mr. D. Hoffman, Big Rock Point Plant Superintendent; K. Berry, Director of Nuclear Licensing; J. Gramza, Chief of Field Maintenance Services; R. Alexander, Technical Engineer; and G. Withrow, Engineering and Maintenance Superintendent. NRC representatives were Mr. C. Norelius, Director, Division of Reactor Projects; N. Chrissotimos, Chief, Reactor Projects Branch 2; D. Boyd, Chief, Section 2D; R. DeFayette; B. Berson; W. Schultz; and T. Rotella, NRR. The NRC voiced its concerns over the violations and the circumstances leading up to them including whether sufficient control and discipline were being maintained over plant maintenance and repair activities. Of special concern were the activities of the field maintenance personnel who are Consumers Power Company employees not regularly assigned to Big Rock Point. The licensee did not disagree with the majority of the findings and presented a chronology and history of the events and corrective actions taken. These corrective actions were quite comprehensive and have the backing of licensee management at the highest company levels. The corrective actions included counseling of personnel, component identification, training, upgrading of procedures, disciplinary action and many others. Outlines of the licensee and NRC presentations are attached. The NRC acknowledged these actions.

10. Open Items

Open items are matters which have been discussed with the licensee, which will be reviewed further by the inspector, and which involve some action on the part of the NRC or Licensee or both. Open items disclosed during the inspection are discussed in Paragraph 3.b.

11. 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.