U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-155/87005(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: January 28 through April 23, 1987

Inspector: S. Guthrie

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

5-21-87
Date

Inspection Summary

Inspection on January 28 through April 23, 1987 (Report No. 50-155/87005(DRP))
Areas Inspected: Routine, unannounced inspection conducted by the Senior Resident Inspector of Licensee Actions on Previous Inspection Findings, Operational Safety, Maintenance Operation, Surveillance Observation, Training, Licensee Event Reports Follow-up, and Licensing Activities.
Results: Of the seven areas inspected, one violation and no deviations were identified. Three items of safety significance are discussed in Section 3.

DETAILS

1. Persons Contacted

*D. Hoffman, 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
R. Barnhart, Senior Quality Assurance Administrator
P. Donnelly, Senior Review Supervisor, Nuclear Activities Department
D. Staton, Shift Supervisor
*W. Trubilowicz, Operations Supervisor
*J. Beer, Chemistry/Health Physics Superintendent
E. Evans, Senior Engineer
D. Kelly, Maintenance Supervisor
D. Ball, Maintenance Supervisor
W. Blosh, Maintenance Engineer
J. Toskey, General Engineer
G. Boss, Reactor Engineer
L. Darrah, Shift Supervisor
J. Horan, Shift Supervisor
R. May, Shift Supervisor
R. Scheels, Shift Supervisor
J. Bradshaw, Property Protection Supervisor
E. Raciborski, Planning and Scheduling Administrator
*J. Werner, Chem/Rad Supervisor
*M. Bielinski, Senior Engineer
*R. Buckner, Nuclear Plant Training Administrator

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

(Closed) Open Item 50-155/86013-11(DRS): Addressing lack of licensee response to concerns raised in IE Notice No. 83-72 for Limitorque Operators. The EQ walkdowns discussed in Section 4.e of this report and Section 3.q of Report No. 155/86002(DRP), describe the results of special inspections of Limitorque Operators.

(Closed) Open Item (155/84011-02): The evaluation of MO-7050, Main Steam Isolation Valve, described in Section 4.j of this report completes the licensee's long term corrective action on failure of the MSIV to close on September 9, 1984.

(Closed) Violation 155-86011-01: Severity Level 4 Violation. The licensee completed all corrective actions associated with communications checks not being performed.

(Closed) Open Item 155/85007-02: Completion of Corrective Actions for four licensee self-identified events. Corrective actions emphasized completion of a comprehensive plant identification program for all components and systems. Final licensee action was completed during the recently completed outage.

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 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 January 31, during attempted performance of Surveillance TR-63, 1A-2B and 2A-2B Breaker Shunt Trip Test, the licensee observed smoke coming from No. 1 Motor Generator (MG) Feeder Breaker No. 52-1A-61. The smoking breaker was observed by an operator located in the station power room during restoration of power after TR-63 was terminated because of failure of the 1A-2B breaker to close as required by the procedure. The fire brigade responded, but smoke quickly stopped coming from breaker 52-1A-61 when the breaker was opened. No flames were observed. A fire watch was posted. Subsequent repairs were made to the motor starter coil which had become overheated when a misaligned limit switch did not actuate properly. Corrective action included coil replacement, switch alignment and testing.

   In compliance with the requirements of Site Emergency Plan Implementing Procedure No. 1, Activation of Emergency Plan, the Shift Supervisor at 0445 hours declared an Alert Emergency Condition.

Procedure No. 1 states that any fire in the station power room represents an on site fire with the potential to affect safety systems and thus receives the Alert classification. When the smoke from the breaker was stopped by opening the 52-1A-61 breaker the fire brigade was recalled and the Alert emergency classification terminated. The licensee made all telephone notifications to state and local law enforcement agencies and to NRC headquarters. The resident was notified at home. Because of the brief duration of the event other features of the licensee's Emergency Plan were not activated, including activation of the Technical Support Center, Operations Support Center, Boyne City Emergency Operation Facility, and General Office response personnel. No accountability of personnel on site was conducted. At the time of the event the reactor was defueled and in cold shutdown.

The inspector reviewed with the licensee the failure of the 1A-2B tie breaker to close during the January 31 attempt at TR-63. Operators were physically unable to lift the breaker operating handle to engage the breaker. Mechanical adjustment of the breaker handle and door corrected the problem. During the second attempt to perform TR-63 on February 1, the 1A-2B tie breaker failed again to close and the test was terminated. Diagnosis of the second failure identified a factory installed misaligned limit switch which failed to make the circuit necessary to permit the EDG to close on bus 2B after the EDG had started, even though the 1A-2B tie breaker had actually tripped. Corrective action included realignment of the limit switch and bench testing. The inspector reviewed the construction of the breaker to determine whether the misaligned limit switch would have prevented the EDG from energizing the 2B bus if called upon to perform its safety function during the recently completed cycle. Weekly performance of Surveillance T7-28, Emergency Diesel Generator Auto Start Test, involves the tripping of the 1A-2B tie breaker and the closing of the EDG on the 2B bus. The condition where the EDG would have started but not closed on the 2B bus because of the misaligned limit switch thus did not exist beyond three days, the period extending back to January 29, when the surveillance was last performed.

Following repairs to the 1A-2B breaker the TR-63 test was successfully performed on February 2. The inspector requested that lessons learned about breaker malfunctions with the potential to prevent safety bus energization be included in operator training. The information has been included in operator requalification training.

During review of the completed procedures for all three attempts of TR-63 the inspector noted several instances where operator signoffs certifying completion of a specific procedural step were signed and then deleted. These deleted signoffs were for steps which, for reasons described above, could not successfully be completed. The inspector discussed with licensee management his concern that procedural steps be signed off only as successfully completed and never signed off in advance of that successful completion. Of particular concern was a deleted signoff of Step 5.47 on February 1 in which the performance of the EDG and associated breakers was signed off as being acceptable and then revised as being unacceptable. Licensee management counseled the operator involved.

b. On January 28 the inspector reviewed licensee action in response to cracks observed in the circumferential welds in the bottom of the outer shell on a Model 1600 shipping cask owned by Chem Nuclear. At the time the cracks were identified by an alert maintenance worker the cask had been loaded with a liner containing low level water from the spent fuel pool and was scheduled for shipment to the Barnwell, South Carolina, burial site. Identified cracks included three of one inch in length, one four inches in length, and one nine inches in length. Nondestructive examination of the cracks revealed that the four and nine inch cracks were actually seven and fourteen inches respectively.

   On January 31 the licensee installed a false bottom/lifting device fabricated by Chem Nuclear which permitted transport of the cask from its staged area within the sphere to the spent fuel pool. The cask was unloaded and on February 2 was returned to the owner after removal from the site. The licensee on February 24 made notification to NMSS required under 10 CFR 71.95.

c. On February 3 the inspector observed the loading of a large liner from the spent fuel pool to the large shipping cask positioned on the reactor deck. After cleaning the liner underwater it was lifted using the reactor crane through the air into the cask. Radiation levels on contact reached 80 R/hr with one hot spot at 400 R/hr on the liner bottom. Because of the shine from the liner the air lift was performed in the late afternoon after many workers had left the site. The containment sphere was evacuated, visitors were prohibited from site access, and open areas where radiation levels were registered during the last cask move were restricted. The crane operator, the only individual directly in the field from the cask, required five minutes to perform the operation in a field of 1200 mr/hr. The involvement of radiation protection personnel and the project engineer was extensive. Materials and tools were staged and the entire evolution was well rehearsed.

   On February 4 the inspector observed the movement of the cask from the reactor deck to the equipment lock area. Contamination control was evident. The inspector observed portions of the air testing of the cask's inner and outer seals. The cask, the final in a series of shipments of old vessel internals previously stored in the spent fuel pool, left the site February 5. Removal of the cask from the containment sphere via the equipment lock required containment integrity be broken for approximately one-half hour. The Plant Superintendent, as required by Technical Specifications and applicable procedures, approved the containment break.

d. On February 3 the licensee notified the Commission via the Emergency Notification System (ENS) that during the test of the 2400 VAC Undervoltage (UV) trip the UV relay was found to be 0.6 volts below the Technical Specification limit of 107.1 volts. The undervoltage scheme is used to protect safety related electrical equipment from a degraded voltage condition. The deficiency was identified during field laboratory testing January 28 and reported to the licensee on February 3. The ENS notification was made within four hours as required by 10 CFR 50.72(b)(2)(iii). Proximate and root cause was determined to be instrument drift. Immediate corrective action involved adjustment of the relay within specification and successful retesting. To prevent recurrence the licensee, prior to startup from the refueling outage, modified the specification on the setting sheet to require a higher as-left setting and reset the UV relay in accordance with the higher as-left setting. The new as-left setting of 108.1 volts is within the acceptance range of 107.1 - 109.2 volts.

e. On February 3 the inspector reviewed the licensee's compensatory fire fighting measures during a period when fire fighting water was isolated from the sphere while performing grinding and nondestructive examination on fire system piping. The licensee staged additional fire fighting hoses and extinguishers and established hourly fire patrols. During the period when the fire piping had to be vented to perform maintenance, a path existed that compromised containment integrity. The Plant Superintendent's permission, as required by Technical Specifications and applicable procedures, was obtained.

f. In response to inquiries and concerns expressed by operators concerning assignment of fire brigade members to tasks which might delay their response to a fire emergency, the licensee on February 10 issued an administrative memorandum to operators intended to establish a policy designated for future incorporation into existing plant procedures. Previously operators had identified several such typical task assignments, including fuel handling activities involving the fuel transfer cask, fuel handling activities conducted underwater within the spent fuel pool, staffing of the Alternate Shutdown Panel, and operation of diesel generators located inside and outside the protected area where high noise levels impede radio contact between control room and operator.

Fuel transfer activities on the reactor deck involve the use of additional operators resulting in three Auxiliary Operators (AO), three Control Operators (CO), and two Shift Supervisors (SS) being on shift, of which one SS and two CO's would be dressed in anticontamination clothing and positioned on the reactor deck. One AO would be required for crane operation. This leaves two AO's and one CO to fill the Operations Department commitment to the Fire Brigade. The memorandum recognizes that an operator on the reactor deck might have to leave while dressed in anticontamination clothing, and authorizes that approach as well as other minor deviations from normal contamination control practices. Operators on the reactor deck would be responsible for safe handling of the fuel being transferred. Fuel is not to be left hanging in the transfer cask and the transfer cask may not be left over the reactor vessel.

The memorandum stressed the need to pre-plan the fire brigade response at the shift meeting as each shift commences, taking into consideration available manpower and anticipated work activities. Responsibility for equipment brought to the scene is designated at that time. The memorandum required review by all five shifts prior to commencement of fuel loading.

g. On February 13 the inspector observed commencement of fuel reload. Prior to commencement the inspector reviewed or observed the following successful tests and checksheets.

(1) Routine control rod coupling integrity checks to satisfy Technical Specification 5.2.2.d.

(2) Functional test of Refueling Interlocks to satisfy Technical Specification 6.3.2.

(3) Functional test of transfer cask safety catch device trip mechanism to satisfy Technical Specification 7.4.7.

(4) Checksheet verification of the operability of the shutdown cooling system to satisfy Technical Specification 4.1.2.b.

(5) Functional test of the Reactor Safety System to satisfy Technical Specification 6.15.

(6) Checksheet to verify operability of Liquid Poison system.

(7) Performance of TR-20, Fission Counting Instrumentation, Calibration, and Neutron Response Check.

Minimum nuclear instrumentation, including both source range channels and dunker detectors installed in the reactor vessel, were verified operable. The trips which are required to be operable with the mode switch in refuel to satisfy Technical Specification 6.3.1 were verified.

The inspector verified that the minimum staffing of the refueling crew required by Technical Specification 7.4.1 was met, and that containment integrity was in effect.

On February 14 reload was halted when excessive noise in newly installed source range nuclear instrumentation Channels 6 and 7 resulted in continuous alarm for short reactor period. Operators observed that neither Channels 6 or 7 displayed the anticipated response to fuel bundle additions and did not display a signal comparable to that displayed by the dunker detectors. The licensee reviewed the electrical background noise characteristics of the cables and amplifiers installed by the new source range modification and concluded that the estimated 300 feet. of cable between the detectors and the preamplifiers installed in the outside cable penetration area resulted in the amplification of both the detector signal and electrical noise. The licensee relocated the preamplifier an estimated 30 feet. from the detector. After that modification background noise had minimal impact on the long cable run carrying the preamplified signal. The licensee, at the close of the period, was evaluating additional minor modifications to enhance operability. Source range instrumentation displayed expected values and fuel load proceeded on February 17 and was completed on February 18. Operators were unable to insert three fuel bundles because of deformation of channels. On February 18 and 19 operators raised the grid bars that hold the channels in place, changed three channels, and reinstalled the grid bars. All control rod drives adjacent to the lifted grid bars were tested, resulting in the removal of control rod drive B-3.

During channel change out activities an underwater light bulb exploded with a popping sound, causing bulb disintegration and separation of the protective glass dome and plastic shield. The dome, shield, bulb socket, and bulb ceramic parts were recovered. A search for glass fragments using a remote control television camera in the local channel and fuel bundle area was unsuccessful.

Throughout the performance of Surveillance TR-46, Fuel Bundle Core Loading Procedure, the inspector verified the performance of subcriticality checks following installation of each bundle. A subcriticality check involves full withdrawal of a control rod adjacent to a newly installed fuel bundle to verify subcriticality. In addition the procedure performed a modified shutdown margin check using the four most reactive control rods in the core. To perform the check the most reactive rod was fully withdrawn and the adjacent rod was withdrawn to notch No. 4 while operators verified subcriticality. The licensee recognized that successful performance of the full shutdown margin test TR-43 on the complete core is necessary to satisfy Technical Specification 5.2.2.b to demonstrate adequate shutdown margin. However, the modified shutdown margin check performed in TR-46 provided operators with assurance that for the four most reactive rods in the core the reactor had at least four notches worth of shutdown margin.

During fuel loading activities the inspector observed the presence and participation of a member of the Reactor Engineering Staff in the control room. Fuel bundle status boards on the refueling deck and in the control room were accurately maintained. Adequate communication between fuel handlers and control room operators was observed. Written procedural control was evident.

h. On February 13 the inspector was notified by the licensee of the overflow of radioactive water from the treated waste hold tank (WHT), situated on a concrete pad outside the turbine building. Operators, at 6:30 A.M. began transferring water from clean waste receiver tanks using the radwaste system. At the time transfer commenced the WHT high level alarm was already annunciated at 82% of task capacity, so operators were not notified by alarm of the full tank. Shift change occurred while the pumping operation continued, and at 8:30 A.M. water was observed running down the side of the tank. No spraying was observed, and as the water ran out of the manway gasket on the tank top most quickly froze on the tank side and concrete pad beneath. The licensee estimated 25 gallons total leakage, of which an undetermined amount dripped off the concrete pad to the surrounding dirt. Technicians gathered the frozen run off, melted it, and collected the liquid using "oil-dry" absorbant for packaging in 55 gallon drums and eventual burial as low level radioactive waste. Dirt adjacent to the concrete was removed until no radioactivity levels above background for the general area were detected, resulting in a hole approximately two feet deep. The contaminated dirt removed filled two 55 gallon barrels intended for transportation to a low level radioactive waste burial site.

The licensee attributed proximate cause of the incident to operator inattentiveness while processing water. The unavailability of warning alarms which were already annunciated and the shift change were contributing factors. Root cause of the incident was considered to be: (1) absence of gasket seal integrity on the manway cover, and/or (2) freezing in the unlagged portion of the overflow line which rises vertically from the tank top and directs overflow to the radwaste tank room floor inside the turbine building. The likelihood of the gasket failure being actual cause is enhanced by the observation that the water flowed from the manway without spraying under pressure and the observation by the maintenance person using a torch to thaw the overflow line that the line did not appear to be frozen based on the pipe's heat absorption characteristics.

The licensee's immediate response included lowering of tank level and the cleanup activity discussed above. The area was appropriately boundaries. On February 17 the licensee completed replacing the manway gasket and insulating the overflow line. The gasket was added to the preventive maintenance program for the WHT. Operators were counseled on the need for alert monitoring of tank levels when high level alarms are already received. The licensee intends to install permanent warning signs at the tank to alert operators to possible gasket leakage caused by the overflow pipe being higher in elevation than the manway. The inspector noted that this is the first of three serious events resulting from operator inattentiveness, each of which involved shift change of operating crews.

i. During the week of February 16 the inspector observed security personnel establishing vital area integrity for the pipe tunnel. The posted security officer compensated for a disassembled physical barrier in the turbine area. On February 23 the inspector discussed with the licensee his concerns over access control based on the inspector's observations. Those concerns were forwarded to a regional security specialist.

j. On February 17 the inspector reviewed with the licensee questions regarding the rod withdrawal sequence proposed for use during initial startup from the refueling outage. The licensee brought to the inspector's attention the remote possibility that the rod notch selected for reaching calculated criticality could add positive reactivity sufficient to cause reactor trip on high reactor period. Based on operating characteristics observed during previous cycles the licensee calculated that while approaching criticality a notch worth of 0.112% reactivity was the value which would result in a trip based on the increase in prompt neutrons experienced when rod motion commences for the notch. The calculated value of reactivity inserted by the notch in question in the proposed sequence is 0.105%. Examples exist in several previous cycles to demonstrate that 0.105% reactivity addition will not result in plant trip. The average notch inserts 0.06% reactivity. Technical Specification 5.2.2 and 5.2.5 require a core shutdown margin of 0.3% reactivity with the control rod highest reactivity worth fully withdrawn from the core. The licensee prepared an alternate sequence as a contingency, but identified the original sequence as the preferred approach in order to gather data useful for study of proposed heavier core reactivity loading for future cycles. Higher reactivity loads could be obtained by adding additional new fuel, reconstituting older fuel, or fuel enrichment. Accurate notch worth data was considered essential to the study. During startup on March 9 the unit did not approach the higher reactivity level anticipated.

k. On February 21-23 the inspector noted establishment of hourly fire patrols during a period when the integrity of the fire barrier in the turbine bypass hydraulic room was broken.

l. On February 22 the licensee, while involved in the removal of Control Rod Drive B3, violated Technical Specification 7.5.7 which requires that the mode switch be locked in the "shutdown" position during drive removal. The purpose of the specification is to prevent the withdrawal of any other control rod while the drive is removed.

Drive removal requires the control rod blade for the drive to be removed be fully withdrawn and uncoupled in order to provide a leak tight sealing surface at the reactor vessel. The drive was uncoupled from the blade prior to shift change in the early morning hours of February 22. This evolution required the mode switch to be placed in the "Refuel" position to permit blade withdrawal prior to uncoupling. The signoff for this step in the Rod Drive Replacement Procedure, MCRD-1, was not completed.

Later on day shift of February 22 Maintenance Personnel using MCRD-1 and recognizing the step requiring the mode switch be placed in "Refuel" was not signed off, requested control room operators to place the mode switch in "Refuel", which was necessary for blade uncoupling but prohibited for drive removal. Control room operators knew or should have known that drive B-3 was uncoupled from its blade, and did not question the request. The Shift Supervisor was not consulted. The mode switch remained in "Refuel" while the drive was changed. A second signoff on MCRD-1 that required operations to lock the mode switch in "Shutdown" prior to drive removal was not signed off. At the time of the event the reactor was refueled except for three bundles and in cold shutdown at atmospheric pressure with the head removed.

Upon notification by a Maintenance Supervisor of the error the licensee's immediate action was to lock the mode switch in "Shutdown" after verification that the drive was in a safe position to be left unattended momentarily and instructing all personnel to exit the control rod drive room. Licensee review determined proximate cause to be a combination of poor communications between departments and failure to follow procedures. Root cause was determined to be personnel error. This is the second of three serious incidents in this inspection period involving communications breakdown over shift change combined with personnel error.

The licensee's long term corrective action emphasized clearly communicating to the staff the safety implications associated with this type of breakdown of control over a major plant evolution. On February 23 the Plant Superintendent, in a memorandum to the Operators and Maintenance Departments, summarized the event and emphasized the significance of the oversight. The memorandum discussed the need for extra attention to plant systems status during refueling outages, the importance of procedural compliance, and the hazard of blind procedural compliance without thought. An engineering evaluation performed February 19 had concluded that adequate shutdown margin for the existing core configuration was assured, indicating no degradation in reactor safety resulting from B3 removal.

The inspector's review concluded that while the actual impact of the evolution was uneventful in terms of fuel integrity, Reactor Protection System functions, and engineered safety features, the serious breakdown in communications and procedural control resulting from personnel error, inattention to detail, and failure to recognize and address abnormal situations implies a level of performance not representative of safe facility operations. The inspector stressed to licensee management the need for immediate reduction in personnel errors. The licensee indicated understanding of and concurrence with the significance of the concerns.

Failure to adhere to the requirements of Technical Specifications 7.5.7 to have the mode switch locked in "Shutdown" during removal of a control rod drive is a violation (155/87005-01(DRP)).

m. On February 23 the inspector observed control rod drive testings on drive B-3. Scram timing, jog performance and insert times were all within specification. Withdraw timing was slow. At the close of the inspection period the licensee was involved in an extensive study involving the vendor which is expected to result in changes to CRD system operations and maintenance. A complete description of problems with the CRD system and the licensee's corrective action will be included in a future report. Prior to fuel load the licensee used extensive vendor assistance to verify operability of all rods.

n. At the inspector's request a Fire Protection Specialist from Region III reviewed the licensee's corrective action for deficiencies identified during the January 9 performance of Surveillance TR-69, Fire Penetration Barriers, Nozzle and Hose Inspection. (Reference Section 4.c of Inspection Report No. 155/87002). The discrepancies identified several lights, pipes, and structural components which were closer than the 18 inches limit to a sprinkler nozzle, creating the possibility of sprinkler flow obstruction. The licensee analyzed the discrepancies and determined no structural modifications were required. The surveillance did not identify combustible materials stored within 18 inches of a sprinkler nozzle. The regional specialist's review concluded that the licensee's evaluation was consistent with the requirements of Generic Letter 86-10, Implementation of Fire Protection Requirements.

o. On March 9 the inspector observed activities in the site security Secondary Alarm Station (SAS). The inspector made specific comments to licensee management pertaining to compensatory measures during periods of inclement weather.

p. On March 9 the reactor was taken critical. Power operation was delayed to perform adjustment and repairs to the exciter. During power escalation the miscalibration of the turbine thrust wear indicator resulted in alarms that required plant power to be held at approximately 67 MWe. Through the end of the inspection period the unusually high unidentified leak rate was under active investigation. Normal values for leak rate are approximately 0.3 gpm. Through the close of the inspection period the values fluctuated between approximately 0.5 and 0.63 gpm. Administrative limits of 0.8 gpm require power reductions and operation above 1.0 gpm is prohibited by Technical Specifications.

On April 9 the reactor was reduced in power from approximately 64 MWe to approximately eight MWe to permit personnel entry into the recirculation pump room, steam drum cavity, and control rod drive room to inspect for leakage. The unit had an unidentified leakage rate of approximately .550 gpm since startup March 10. Minor packing leakage on VNS-131, a recirculation pump instrument isolation valve, and leakage via the "B" train of the Reactor Depressurization System was identified. The licensee began design of a collection system to quantify the leakage to be installed during a future outage. During the power reduction additional inspections were conducted on CV-4050, Liquid Poison Control Valve, and on environmentally qualified cables located in the recirculation pump room. The unit began power escalation on April 10 to return full power operation within the restrictions imposed by the turbine thrust bearing wear indicator.

q. On March 17 the inspector observed portions of the licensee's practice for the 1987 annual emergency exercise scheduled for April. The practice was conducted during off hours. The licensee's evaluation of their overall performance pointed to problems with communications. Communication hardware problems were addressed by relocating and combining several phone lines to provide the Site Emergency Director with single location access to telephone lines. The telefax machine was relocated for improved access. The exercise pointed out the need for more practice for individuals not familiar with the pace and pressure of exercise scenarios. The licensee is considering a program of short drills with limited participation on a monthly basis throughout the year to address specific observed deficiencies and provide exercise participants with practical experience.

r. On March 25 the licensee conducted a small scale practice exercise for the Control Room (CR) and Technical Support Center (TSC) staffs and involving limited Emergency Operations Facility (EOF) and State of Michigan participation. The drill used a realistic scenario and was designed to enhance communications between the CR and TSC, SED and the TSC staff, and between the TSC and EOF and State of Michigan. The inspector observed the entire drill and made comments to the licensee that emphasized the need for greater communication between operators and the Shift Supervisor to promote teamwork and a diagnostic approach to the scenario.

On April 7 the inspector participated in the annual Emergency Exercise, conducted on both shifts. The inspector noted that the teamwork among participants and methodical approach to solutions was exemplary. The inspector's comments were incorporated into Report No. 155/87008(DRSS).

s. On March 27 the inspector met with the licensee to discuss proposed changes to the Radiation Work Permit (RWP). One significant change would remove the RWP from the publicly accessible wall mounted area where individual workers could refer to the document for radiological requirements and record dosimeter exposure. The permits would be maintained by radiation protection technicians who, when contacted by maintenance personnel, would review or conduct surveys, establish protection criteria and hold points in the proposed work, and specify protective clothing and equipment. All of the written requirements would then be integrated into the job preplanning process that proved to be beneficial during the 1987 outage.

The inspector also discussed with the licensee their plans to restrict personnel movement across the orange lines that designate radiologically controlled areas throughout the plant in an attempt to provide tighter contamination control. By memorandum to all Big Rock Point personnel the Plant Superintendent on March 31 reiterated the need to develop good radiation work and personnel monitoring practices with the goal of regulatory performance improvement and prevention of serious personnel or off-site contaminations. The memorandum cited several instances of contaminations outside controlled areas and observations in plant audits that personnel were not following contamination control practices. After redesignation of certain controlled areas, the only exit permitted will be at access control on the second floor of the office building. The machine shop area radiologically controlled boundary was modified and smoking, eating, or chewing, previously allowed in the shop area, was prohibited. The shop drinking fountain remained in place. The licensee noted that because of manpower unavailability the radiological practices training scheduled for integration into the operator's training cycle will not occur as discussed in Section 5.a of Report No. 155/87002(DRP). The licensee is instead researching means of enhancing initial and advanced radiation worker training. The licensee continued to recognize the need for tighter contamination control and greater personal accountability in controlling contamination.

t. On April 2 the inspector reviewed with the licensee recent events at the Peach Bottom Nuclear Power Plant involving operators sleeping on duty which resulted in an ordered shutdown of that facility. Based on interviews with licensed operators and other members of the Big Rock Plant staff, licensee personnel are aware of the serious nature of the problem and that the need for attentiveness is essential for the safe operation of the facility. The inspector has made unannounced visits to the Big Rock control room during back shifts on numerous occasions over the last two years with no observed instances of operator inattentiveness or sleeping at the controls. The licensee adheres to Technical Specifications limitations on length of work shifts for control room operators, and conducts periodic unannounced management visits on backshifts.

u. On April 10, during performance of a heat balance calculation following one notch of control rod withdrawal, the positive reactivity addition resulting from Xenon burnout caused operators to exceed power escalation rates. Technical Specifications limits rate of change of reactor power to less than 20 MWt/minute between 120 MWt and 200 MWT reactor power. Standard Operating Procedure SOP 1, Reactor Operations, limits power escalation rates to those specified in the Technical Data Book, Section 15.5.A.5., which is updated for each cycle's physics characteristics. Section 15.5.A.5 limits power escalation to 4.7 MWt/hr.

The licensee's review at the time of the incident determined that power increased from 132.4 MWt to 151.2 MWt, as measured by Power Range Nuclear Instrumentation, between 0815 and 1050, corresponding to a rate of 7.28 MWt/hr. The heat balance indicated picometers reading one to five percent higher than actual calculated power, indicating a maximum corrected power of 146 MWt. The engineering analysis conducted immediately by the Reactor Engineer concluded that no thermal limits were approached and that the threshold power of 146.5 MWt, below which fuel conditioning is not required, was not exceeded.

Licensee review concluded that control room operators were inattentive to the power escalation, which was increasing faster than the administrative limits for fuel preconditioning. Operators were determined to be aware of the increasing power resulting from the control rod notch withdrawn on the previous shift, but apparently did not recognize the rapid rate of Xenon burnout. The Corrective Action Review Board review indicated that power escalation rates were conservatively low for the just commenced Cycle 22 and indicated to the inspector that operators may have been anticipating an escalation rate and limit consistent with previous operating cycles. Immediate corrective action included the insertion of the control rod one notch to cause a power reduction and completion of the engineering analysis. The licensee immediately counseled the operators involved and began an evaluation of the need for remedial operation training. An evaluation of the conservative power escalation rates for appropriateness was scheduled. A PRC review identified the need for additional training on physics changes similar to the training provided operators on facility modifications.

The inspector concluded that while the safety significance of an operator error that results in a power escalation rate in excess of administrative limits is significant, the actual potential for damage to fuel integrity was minimal. The inspector's review concluded that the escalation rates set forth by Section 15.5.A.5 were conservatively set well below the limits established in the Cycle 22 Reactor Physics package. The inspector expressed his concern that assumptions on the part of operators that performance of any plant component, system, or parameter will always be consistent or predictable is not representative of conservative, attentive plant operation. The inspector noted that this is the third significant event attributable to personnel error in this inspection period, and that each of these significant events involved a shift change of operating crews. The inspector stressed the need to improve communications between offgoing operators and their replacements to ensure an orderly transfer of control.

v. During the inspection the inspector reviewed with the licensee the continued indication throughout the recently completed operating cycle of a small primary to secondary leak across the primary boundary formed by the tubes and tube sheet of the emergency condenser. At the start of Cycle 21 cycle Xenon analysis indicated no leakage and throughout the cycle the tube bundles were considered by the Plant Review Committee (PRC) to be fully operable. Leak detection testing on suspect tube bundle No. 2 failed to identify leakage. (Reference Report No. 155/85014(DRP), Section 4.j.) However, a program of tritium analysis of shell side water throughout the cycle indicated a steadily increasing level. Licensee calculations based on the tritium analysis estimate a leak rate of 0.0002 gpm or about one liter/day. Sampling indicated increased levels of Xenon in shell side water associated with shutdown and startup for two outages in 1986.

   The inspector expressed a concern that further analysis was warranted in view of steadily rising tritium levels. The failure mode of the defect upon activation of the emergency condenser, the accuracy and implications of the tritium analysis methodology, quantification of the leak rate, and possible leak testing of the tube bundle not tested in 1985 were all items of concern discussed. The licensee committed to submit a comprehensive review of the situation for staff review within approximately thirty days. The emergency condenser leak will be tracked as Open Item 155/87005-02(DRP).

One violation was identified in this area.

4. 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. During the period the inspector observed and reviewed acceptance testing for the Diesel Fire Pump drives replaced earlier in the outage. Previous inspection activity on this topic is presented in Section 3.g of Report No. 155/87002(DRP). The engine satisfactorily completed the following acceptance tests:

   (1) Surveillance T7-23, Battery voltage and Electrolyte Level
   (2) Surveillance TSD-01
   (3) Manufacture's post installation testing prior to turnover to the licensee.
   (4) Automatic Start Tests, including automatic start using Reactor Depressurization System circuitry.
   (5) Manual Start
   (6) One hour record run
   (7) Surveillance TR-70, Fire Suppression System Functional Test and Pump Capacity Test.
   (8) I&C calibration of control circuitry and pressure switches. Vendor and record run testing indicated consistency in engine speed, oil pressure, temperature and fuel consumption. Plotting of pump flow (gpm) against pump discharge pressure (psig) indicated pump performance consistently above the 100 gpm at 110 psig requirement of Technical Specification 4.7.11.1.d.3.

   During review of TR-70 the inspector noted deletions of operator verification for acceptable performance of both the electric fire pump in Step 5.5 and the diesel fire pump in Step 5.14. Interviews revealed that the initial attempt to start the engine was unsatisfactory because the valve specified in the procedure for use in bleeding pressure off the firemain header could not be throttled closely enough to obtain accurate start data. Use of a different valve provided accurate data that indicated acceptable performance.

b. On February 12 the inspector reviewed results of Environmental Qualification Walkdowns of Limitorque Motor Operated Valves MO-7050, Main Steam Isolation Valve, and MO-7051 and MO-7061, Primary Core

Spray Isolation Valves. The walkdowns were performed using checksheets sufficiently detailed to gather data necessary to address the concerns in IE Notice 83-72 covering Limitorque operators. The walkdowns verified that limit switches, terminal blocks, torque switches, rotors, and structural components were of the correct material and intact. A general inspection of wiring condition was conducted. Acceptable grease samples were obtained. Motor heaters were not installed.

c. In response to recent secondary side feedwater line breaks at another nuclear facility the licensee during the 1987 outage voluntarily conducted a program of Ultrasonic Testing (UT) of all elbows, high flow T's and reducers on selected feedwater and main steam piping segments. The licensee conducted 21 examinations of feedwater piping downstream of feedwater pumps through the high pressure feed heaters, feedwater piping on the pump's inlet side located on the turbine deck, and main steam piping in the pipe tunnel from containment to the turbine stop valve. All inspections verified normal wall thickness. All inspections were conducted on six and eight carbon steel piping not previously examined by the ISI program. The licensee used as criteria in their choice of piping to be inspected the evidence of high fluid flow, elevated temperature, and personnel accessibility.

d. On February 10 the inspector reviewed changes made to Surveillance TR-28, Steam Drum Relief Valve Set Point and Acceptance Determination. Procedural changes resulted from inspector's concerns over the importance of "as-found" setpoints during relief valve testing presented in Report No. 155/87002(DRP), Section 4.s. The changes included: (1) specific guidance on lapping compounds and grits, (2) specific cleaning instructions, and (3) revised acceptance criteria. The revision specifies that the "as-found" (first relief attempt) value is the value to be compared to the acceptance criteria. The acceptance criteria is specified in the procedure.

As part of the review the inspector examined Quality Assurance Deviation Report (DR) QB-86-02 dated March 19, 1986. The DR describes failure of steam drum relief valve RV 5001 to meet the acceptance criteria of 1545 plus or minus five psig during tests on September 23, 1985, during the last outage in which the valve lifted out of specifications on two of three attempts. The first test reading of 1650 psig was considered to be questionable due to test conditions and thus not used to verify test and code acceptability. The licensee considered the results of the second attempt at 1540 psig to be representative and the valve was declared acceptable. Licensee management recognized the need for improvements in test method and procedural control and addressed the concerns under a separate DR. The QA DR noted inadequacies in description of test method and failure to include acceptance criteria. The DR noted failure to process approved procedural changes when the need for an improved test method was first identified. Th DR noted that failure to document hardware problems, failure to perform activities in accordance with written procedures and subsequent failure to include acceptance criteria and detailed testing methodology all violated requirements found in Nuclear Operations Department Standards, ASME Section XI (IWV), and the Quality Assurance Program Description, CPC-2A. Test methodology was deficient in providing test equipment that would permit accurate determination of lift pressure. Individuals observing the gauge would often flinch at the explosive sound of pressure relieving, and the test rig did not permit slow pressure increases.

The inspector concluded that many of the inadequacies identified in the QA DR were not addressed prior to commencement of the 1987 outage, but that the recent changes described above make significant strides toward resolving the deficiencies. Acceptance criteria and test methodology have improved and a new test gauge registers maximum pressure attained prior to lifts. The licensee failed to resolve the discrepancy between the lift pressures specified in the procedure and those listed in Standard Operating Procedure (SOP) 29, Step 9.2.3. A review of the ISI program indicated the lift pressures specified in the procedure were correct, and the licensee corrected the discrepancy.

e. On February 4 the inspector observed maintenance on Limitorque Valve MO-7068, Backup Enclosure Spray Isolation Valve. This environmentally unqualified valve was the subject of Unresolved Item 155/86013-05(DRS) and was addressed in Section 4.q of Report 155/87002(DRP). The inspector observed the installation of the stem nut and locking ring and observed portions of limit switch setting.

   On February 5 the inspector observed assembly of RayChem splices on the valves motor leads. Splice design and installation were consistent with the vendor's instructions for proper size and length of coverage and were crafted in a workman like manner. Project engineer and Quality Control involvement was extensive. Post maintenance testing revealed failure to stroke open or closed. The licensee verified wiring accuracy and integrity and motor starter operability. Using vendor recommendations the stem was lubricated to minimize drag following the installation of the new stem nut, resulting in satisfactory stroking. The valve was stroke tested under Surveillance TR-88, Core Spray and Enclosure Spray Initiation and Operability Test, as a prerequisite to startup.

f. On February 10 the inspector observed maintenance activities on Limitorque Valve MO-N001B, Reactor Recirculation Pump No. 2 Discharge Valve. The valve was disassembled and inspected while performing a grease change out after the original grease was observed during a surveillance earlier in the outage to be deteriorating. The inspector noted that daily contamination surveys identified the shop area where the work was in progress as being slightly contaminated, resulting in the appropriate boundaries being established.

g. On February 13 the inspector reviewed licensee actions in response to failure of the Core Spray Valves MO-7051 and MO-7061 to stroke during Surveillance TR-97. The valves are stroked open and closed monthly during Surveillance T-30-22, Emergency Core Cooling System Valve Tests, last performed on December 24, 1986. The T-30-22 test was not performed in January because of refueling activities, but the valves were stroked on several occasions during the outage. Investigation by a maintenance supervisor revealed accumulated grease and dirt on the valve stem and, in the case of MO-7051, the bracket which holds the torque switch contacts in alignment had loosened slightly and caused the torque switch to open. Immediate corrective action involved tightening the torque switch brackets to reestablish contact alignment and cleaning and lubricating the stems. Each valve was stroked fully open and closed six times during a 24 hour period on February 11 and 12 with acceptable and consistent stroke times observed. Surveillance TR-97 was successfully completed on February 11. Long term action included adding the bracket check to Preventive Maintenance Procedures for the motor operated valves, and periodic cleaning and lubrication of exposed stems. A proposal to fabricate and install a dust cover over the exposed stems to protect from dirt falling from an open grate walkway above the valves was evaluated as being unnecessary. The inspector expressed a concern that given the significance of the core spray valves in keeping the core covered during accident scenarios and the relative simplicity and low cost of installing a lightweight dust shield the action appeared warranted. Prior to startup the licensee fabricated and installed a lightweight metal dust cover.

   On February 13 following identification of loose torque switch bracket retaining bolts in MO7051 the licensee performed inspection on all other Q-listed motor operated valves. Loose bolts were discovered on approximately 25% of the 24 motor operated valves examined. None of the valves with loose bolts had exhibited any unusual behavior that would cause reliability to be suspect. Loose bolts were retorqued using "loctite" thread sealant. Several stems were cleaned.

h. On February 17 the inspection reviewed with the licensee the contents of IE Information Notice 87-08, Degraded Motor Leads in Limitorque DC Motor Operators. The licensee reviewed their equipment data base and determined that the suspect motors manufactured in 1984-1985 and having specific serial numbers were not installed at Big Rock Point.

i. During the period the inspector reviewed the vibration testing program conducted by the Production and Performance Department to determine its impact on maintenance work performed during the outage. Based on vibration analysis and trending performed over the recently completed operating cycle the following major problems were identified and corrected:

(1) Service Water Pump No. 1 was disassembled to identify a worn shaft. The pump was rebuilt with a new shaft and returned to operable status on February 12.

(2) Reactor Feedwater Pump No. 1 received a motor inspection that identified loose laminations and the need to refit a bearing housing. Repairs were completed during the outage.

(3) Reactor Feedwater Pump No. 2 was diagnosed as having thrust bearing problems on pump and motor. Oil sample analysis confirmed high particulate content in a common system serving both pump and motor., Thrust bearing repairs were completed during the outage.

(4) The Emergency Diesel Generator trending showed vibration in the generator end. The licensee checked foundation bolts, alignment, and coupling integrity. While some vibration was identified the long term trend of monthly data indicates a consistent level that is not increasing. The licensee has procured vibration monitoring equipment with enhanced sensitivity and expects to continue monthly checks.

j. During the inspection period the inspector observed and reviewed testing of Limitorque direct current operators on MO-7050 (Main Steam Isolation Valve (MSIV)) and MO-7067 (Turbine Bypass Isolation Valve) performed by MOVATS, Inc. The MSIV has a history of problems, the most recent a failure to close on September 9, 1984. That failure and others are described in Section 4.a of Report No. 155/84011. The MSIV at Big Rock is of particular safety significance since it is the only isolable valve in the main steam line exiting containment. The normally open turbine bypass isolation valve is located in the bypass line to the main condenser downstream of the MSIV and upstream of the normally closed bypass valve. It is provided to allow operators to isolate the turbine bypass line from the main condenser on failure of the hydraulically operated bypass valve. The valve closes on loss of condenser vacuum. During the recently completed operating cycle MO-7067 demonstrated reliable performance during closing but failed to respond to opening signals.

The MOVATS evaluation of the MSIV determined that the valve stopped on actuation of limit switches and coasted into the backseat at 25% of full thrust. Both valve operators were observed to have limit switches set very close to the end of valve travel. While it is desirable to have the limit switch as close as possible to the end of valve travel for valve position indication this configuration creates the possibility of decreased torque switch bypass times. The torque switch bypass function is activated by contacts on the close limit switch and permits the valve to travel off its seat without tripping out on the increased torque needed for unseating. If the limit switch actuates too early torque switch bypass is lost and the valve may fail to open. Neither valve opens to perform any safety function. MOVATS recommends a switch setting of 20-25% valve travel for torque bypass, but the licensee indicated reluctance to increase the potential for operator confusion by setting the switch to indicate fully closed when it is actually 20-25% open. Licensee procedural guidance has set limits of 5% of total valve travel, and that was increased to 7% for both valves. On March 11 the inspector reviewed the 7% setting with MOVATS management and concluded that for the Big Rock application the 7% setting provided adequate margin of reliability that the torque switch would not interfere with valve operation.

k. On February 23 the inspector observed portions of overhaul activity on steam drum relief valve RV-5045. The relief valve was rebuilt when as-found relief setting was determined to be 1697 psig. The relief is specified to lift at 1575 plus or minus five psig. Concerns over acceptance testing and maintenance practices were presented in Section 3.s of Report No. 155/87002. The testing and repairs were conducted using a recently revised Surveillance TR-28, Steam Drum Relief Valve Recondition and Setpoint Verification that satisfied the concerns expressed in 155/87002. The licensee used a vendor representative to remove small defects in the nozzle seat.

l. During a regular review of Deviation Reports the inspector learned of installation of valve VAE-28 without proper documentation. The valve, which is Q-tested to designate its quality controlled status, was issued as non-Q due to personnel error in the stockroom. The valve was installed and successfully passed nondestructive testing for weld integrity before a maintenance supervisor noted the missing ticket that by procedure accompanies a Q listed component. The licensee was able to reconstruct the required documentation to allow receipt inspection and the valve remained in place.

No violations or deviations were identified in this area.

5. Surveillance Observation

a. On January 28 the inspector observed portions of TR-28, Steam Drum Relief Valve - Recondition and Set Point Verification for relief Valve Serial No. A-0.

b. On February 8-9 the inspector observed portions of TR-01, Control Rod Drive (CRD) Performance Testing. The surveillance tests scram timing, verifies rod coupling integrity, and verified CRD withdrawal and insert timing and rate set valve position for the 32 control rods.

   Section A of TR-01 performs scram time testing of individual rods using a strip recorder. Acceptance criteria requires 90% insertion within 2.5 seconds and a review of the strip charts indicate all fell within the 1.10 - 1.48 record range.

   Section B of TR-01 verifies coupling integrity by withdrawal of the rod to the full out position (indicated position 23) and attempting to continue withdrawal. Continued withdrawal indicates loss of coupling integrity and is indicated by appearance of a rod bottom light on the main control panel. No lights were received.

   Section C of TR-01 conducts withdrawal and insert timing checks. All rods checked were within the 27 plus or minus one second requirement for insertion but six rods were slower than the 36 plus 2 minus 0 second specification for withdrawal. On February 9 the inspector observed portions of Surveillance O-CRD-9, Trouble Shooting CRD Poor Performance. Problems contributing to slow withdrawal times included poor quality water that clogged screens and damaged seals and low temperature (40 F) drive water. One drive required repair of a leaking scram inlet valve. All drives were repaired and retested within specifications except for B-3, which continued to perform smoothly but slowly on withdrawl. Vendor input did not correct the problem. On February 12 the licensee commenced fuel reload with drive B-3 exhibiting slow withdrawal times. While outside the acceptance criteria for withdrawal time the deficiency is conservative in nature since reduced rod withdrawal speed results in reduced rate of reactivity change during rod movement.

c. On March 25 the inspector observed portions of annual Surveillance T-365-18, Emergency Notification System Surveillance Test. The inspector noted that the Emergency Notification System (ENS) hotline between NRC Headquarters and the Emergency Operations Facility (EOF) in Boyne City, Michigan was inoperable based on NRC's inability to hear voice communication. The ENS line from the EOF has a history of inoperability. The inspector verified that the licensee has notified NRC monthly since September, 1986, of the telephone line's inoperability without response or repair activity being initiated.

6. Training

a. On February 13 the inspector observed training on the newly installed Source Range Nuclear instrumentation provided for control room operators. The individual operators had not previously been trained on the new equipment. The training was conducted shortly before fuel reload commenced. The training familiarized operators with the calibration functions, check sheets, and operating characteristics of the instrumentation.

b. On March 3 the inspector observed training conducted by the site Emergency Planning Coordinator for persons with Site Emergency Plan responsibilities in the Technical Support Center (TSC). The training was conducted prior to the annual emergency exercise and drill. The classroom portion of the training included instruction in TSC layout and equipment, TSC activation, reporting locations, status board maintenance, communications facilities and practices, and procedures for turnover of responsibility to individuals during TSC activation. The instructor described the duties and performance expectations for each individual attending the class. Following an examination the class toured the TSC and reviewed equipment and duties. The lesson plan and objectives of the class were clearly defined and thoroughly prepared, and the instructor presented the material in an organized and professional manner.

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 February 27 the licensee submitted LER 87-003, Inoperable Primary System Safety Valves. The submittal was revised on March 5 to correct certain clerical errors in the original. Details of the Safety Valve issue are presented in Section 4.d of this report and Section 4.s of Report to 155/87002(DRP). The inspector discussed with the licensee certain technical inaccuracies in the submittal, specifically the statement that "failures occurred on the first 'pop' and subsequent tests were satisfactory." The inspector's review of valves pop tested during the 1987 outage determined that of seven valves tested only one (Serial No. A-3) was subjected to subsequent testing and that those lift points were below specification. The inaccuracy was of particular concern to the inspector because of a later contention in the "Safety Assessment" portion of the submittal that return of the valves to proper operation on subsequent lifts indicates Liquid Poison System (LPS) injection would not be impeded by high plant pressure. The licensee committed to revise their submittal to correct the inaccuracy and readdress the issue of LPS operability. The inspector reviewed the licensee's analysis concerning LPS operability and concluded that given the as-found set points of the four reliefs with the lowest values, primary plant pressure would have been reduced sufficiently to permit poison injection. The LER is considered closed.

By letter dated March 3 the licensee submitted Licensee Event Report (LER) 87-002, Relay Drift Causing Undervoltage Trip to be Inoperable. The event is discussed in detail in Section 3.d of this report. The LER is considered closed.

By letter dated March 12 the licensee submitted LER 87004, Inoperable Reactor Depressurization Snubbers per Technical Specification 3.1.5. The LER described failure of two of six mechanical snubbers to meet maximum drag force requirements. The snubber issue was the subject of a special inspection by a Region III specialist on February 5 and 6. (Reference Report No. 50-155/87007(DRS)). The licensee obtained concurrence of Region III management to take additional time for the preparation and submittal of this LER. The LER is considered closed.

By letter dated March 24 the licensee submitted LER 87005, Personnel Error Resulting In Technical Specifications Violation. The incident is discussed in detail in Section 3.1 of this report. The LER is considered closed.

8. Licensing Activities

By letter dated January 28 the Commission issued Amendment No. 87 to Facility Operating Licensing No. DRP-6. The amendment revised technical specifications to reflect changes to Source Range Nuclear Instrumentation resulting from a recent facility change. The term "source range" replaces "startup range" throughout technical specifications.

By letter dated February 12 the staff of NRR denied approval of Technical Specification Changes to reference use of Reload I-2 fuel and hybrid control rods in Cycle 22. The staff referenced concerns that existing portions of technical specifications, which were not changed by the licensee's submittal, do not provide adequate protection against exceeding core operating parameters using the new core reload. The licensee, during a February 2 conference call, committed to revise and resubmit the reload portion of the request. That portion of the application pertaining to hybrid control rods in Cycle 22 was reviewed as a separate licensing action. By letter dated February 19 the Commission issued Amendment No. 89 to Facility Operating Licensee No. DPR-6, thereby revising Section 5.2.1.b of Technical Specifications. With the amendment the staff approved fuel reload I-2, including a revised table of uncertainty factors associated with the thermal hydraulic parameters for the reload. The approval was issued on an emergency basis in accordance with the requirements of 10 CFR 50.91(a)(5).

By letter dated February 17 the Commission issued Amendment No. 88 to Facility Operating Licensee No. DRP-6, thereby revising Technical Specifications 5.1 to reflect the use of new hybrid control rods in the Cycle 22 core.

By letter dated February 17 the Commission issued an exemption from the requirements of 10 CFR 50, Appendix R, Section III.j. The exemption grants relief from the requirement that lighting units with a minimum eight hour battery power supply be provided in all areas necessary for access to safe shutdown equipment. The licensee has demonstrated their ability to effectively use hand held lanterns to illuminate access and egress routes to buildings within the protected area and to operate the standby diesel generator.

By letter dated March 2 the staff of NRR issued an exemption from the scheduler requirements of 10 CFR 50.71(e)(3)(ii). The licensee is required to submit an updated Final Hazard Summary Report (FHSR) in response to the Final Integrated Plant Safety System Assessment Report (IPSAR), NUREG-0828. The exemption grants the licensee additional time to prepare the update FHSR. The licensee recently assigned additional personnel to the project.

9. 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.v.

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.