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U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No. 50-334/84-33

Docket No. 50-334 License No. DPR-66

Licensee: Duquesne Light Company
One Oxford Center
301 Grant Street
Pittsburgh, Pennsylvania 15279

Facility Name: Beaver Valley Power Station, Unit 1

Inspection At: Shippingport, Pennsylvania

Inspection Conducted: December 10, 1984 - January 7, 1985.

Inspectors: Wm. Troskoski 1-17-85
W. M. Troskoski, Senior Resident Inspector date signed

DM Johnson 1/17/85
D. M. Johnson, Resident Inspector date signed

Approved by: L. E. Tripp 1/19/85
L. E. Tripp, Chief, Reactor Projects Section No. 3A, Reactor Projects Branch 3 date signed

Inspection Summary: Inspection No. 50-334/84-33 on December 10, 1984 - January 7, 1985.

Areas Inspected: Routine inspections by the resident inspectors (118 hours) of licensee actions on previous inspection findings, plant operations, housekeeping, fire protection, radiological controls, physical security, unit startup after a refueling outage, equipment qualification modification, surveillance activities, outage maintenance and modification activities, allegation followup, and licensee event reports.

Results: Two violations (failure to submit an employee termination radiation exposure report - detail 3.d, and failure to follow equipment control procedures - detail 3.b.5), and two safety concerns (RCS boron dilution - detail 3.b.1, and containment integrity not established prior to entering Mode 4 - detail 3.b.6) were identified.

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DETAILS

1. Persons Contacted

   J. J. Carey, Vice President, Nuclear Group
   R. J. Druga, Manager, Technical Services
   K. D. Grada, Manager, Nuclear Safety
   T. D. Jones, General Manager, Nuclear Operations
   W. S. Lacey, Plant Manager
   J. D. Sieber, General Manager, Nuclear Services
   N. R. Tonet, General Manager, Nuclear Engineering and Construction Unit

   The inspectors also contacted other licensee employees and contractors during this inspection.

2. The NRC Outstanding Items (OI) List was reviewed with cognizant licensee personnel. Items selected by the inspectors were subsequently reviewed through discussions with licensee personnel, documentation reviews and field inspection to determine whether licensee actions specified in the OI's had been satisfactorily completed. The overall status of previously identified inspection findings were reviewed, and planned and completed licensee actions were discussed for those items reported below:

   (Open) Unresolved Item (84-22-01): Evaluate excessive setpoint drift on steam generator safety valves. This item was last discussed in Detail 7 of NRC Inspection Report 50-334/84-25. On December 29, 1984, the inspector observed hot testing of the 5 main steam safety valves with a worst history of setpoint drift. Test results indicated no drift for three of the MSSVs, a drift of 1-1/2% high for another, and a drift of 1-1/2% low for the last one. Setpoints for all five MSSVs were conservatively adjusted to the lower range. This item remains open as the licensee is currently pursuing a technical spedification change which would allow a 3% setpoint drift, as specified in the Standard Technical Specification.

   (Closed) Unresolved Item (84-04-04): Evaluate the Auxiliary Feedwater System (AFW) to main feed tie-in piping to assure no degradation below design basis minimum wall thickness. During the fourth refueling outage, an ultrasonic inspection was performed at various points on the AFW piping between the last isolation valve and the connection point to the main feed piping. The results indicated that the design basis minimum wall thickness as calculated per ANSI B31.1 (1967 ed.) paragraph 104.1.2 was above the minimum value for all points examined (EM 90067). The inspection did reveal that two points were below the manufacturer's minimum wall requirements (nominal wall - 12.5%). The licensee has recommended that these localized thin areas be built up by weld repair, and an MWR has been issued to accomplish this repair. The inspectors had no other concerns and this item is closed.

3. Plant Operations

a. General

Inspection tours of the plant areas listed below were conducted during both day and night shifts with respect to Technical Specification (TS) compliance, housekeeping and cleanliness, fire protection, radiation control, physical security and plant protection, operational and maintenance administrative controls.

- Control Room
- Primary Auxiliary Building
- Turbine Building
- Service Building
- Main Intake Structure
- Main Steam Valve Room
- Purge Duct Room
- East/West Cable Vaults
- Emergency Diesel Generator
- Containment Building
- Penetration Areas
- Safeguards Areas
- Various SwitchgearRooms/Cable Spreading Room
- Protected Areas

Acceptance criteria for the above areas included the following:

- BVPS FSAR
- Technical Specifications (TS)
- BVPS Operating Manual (OM), Chapter 48, Conduct of Operations
- OM 1.48.5, Section D, Jumpers and Lifted Leads
- OM 1.48.6, Clearance Procedures
- OM 1.48.8, Records
- OM 1.48.9, Rules of Practice
- OM Chapter 55A, Periodic Checks - Operating Surveillance Tests
- BVPS Maintenance Manual (MM), Chapter 1, Conduct of Maintenance
- BVPS Radcon Manual (RCM)
- 10 CFR 50.54(k), Control Room Manning Requirements
- BVPS Site/Station Administrative Procedures (SAP)
- BVPS Physical Security Plan (PSP)
- Inspector Judgement

b. Operations

The inspectors toured the Control Room regularly to verify compliance with NRC requirements and facility technical specifications (TS). Direct observations of instrumentation, recorder traces and control panels were made for items important to safety. Included in the reviews were the rod position indicators, nuclear instrumentation systems, radiation monitors, containment pressure and temperature parameters, onsite/offsite emergency power sources, availability of reactor protection systems and proper alignment of engineered safety feature systems. Where an abnormal condition existed such as out-of-service equipment, adherence to appropriate TS action statements was independently verified. Also, various operation logs and records, including completed surveillance tests, equipment clearance permits in progress, status board maintenance and temporary operating procedures were reviewed on a sampling basis for compliance with technical specifications and those administrative controls listed in paragraph 3a.

During the course of the inspection, discussions were conducted with operators concerning reasons for selected annunciators and knowledge of recent changes to procedures, facility configuration and plant conditions. The inspectors verified adherence to approved procedures for ongoing activities observed. Shift turnovers were witnessed and staffing requirements confirmed. Except where noted below, inspector comments or questions resulting from these daily reviews were acceptably resolved by licensee personnel.

1. During a review of control room logs on December 15, 1984, the inspector noted that reactor coolant system (RCS) boron concentration had been diluted from about 2380 ppm to 1620 ppm. The normal range during outage conditions is 1950 - 2050 ppm. From discussions with operations personnel, it was determined that the initial high concentration was due to a blender malfunction (flow meter from boric acid tank) and it was desired to return the RCS boron concentration to within the normal band.

   OM Procedure 1.7.4N, Blender Dilution Operation, basically requires the operator to:

   (1) determine existing RCS boron concentration from chemistry samples;

   (2) estimate the volume of makeup water based on the boron dilution nomograph (OM Chapter 7);

   (3) dilute the desired quantity; and,

   (4) obtain another RCS boron sample for further concentration changes, if necessary.

Through a review of plant conditions, the inspector determined that the dilution nomographs referenced in OM 1.7.4N, were inappropriate for the circumstances; the "A" RCS loop was isolated, the primary system had not yet been vented following refueling, the RCS circulation flow was provided by the RHR system, and the reactor coolant pumps had not yet been bumped. Hense, the operators could not make a reliable estimate of the total RCS water inventory to calculate the volume of makeup water necessary to achieve a specific dilution.

Chemistry records of RCS boron samples and Control Room logs were reviewed to determine the sequence of events. On December 14, 1984, the licensee knew of the high RCS boron concentration. At 11:25 a.m. an initial dilution intending to add 10,000 gallons of primary grade makeup water, was begun. The inspector could not determine whether a chemistry sample had been pulled earlier that day as the chemistry logs showed no entry prior to about 3:00 p.m. It appears that the operators used the last results from the previous day. Although no dilution had occurred since that sample was taken, this was contrary to OM Procedure 1.7.4N, which requires chemistry sampling before dilution. The evolution was terminated after adding only 5,000 gallons of water, and Chemistry reported a sample result of 2383 ppm. Another 3,000 gallons of makeup water was added between 4:41 - 5:45 p.m., and two subsequent chemistry samples yielded results of 2159 ppm and 2126 ppm.

On December 15, 1984, the addition of about 13,000 gallons of makeup water was initiated at 5:15 a.m. This amount of dilution was based on an incorrect calculation that used the RCS solid volume. A chemistry sample at 5:50 a.m. yielded 2310 ppm, a concentration higher than the previous shift due to an inadvertent boration that occurred while lining up the boric acid tank to the VCT with the emergency boration valve open. No further samples were requested until after completion of the 13,000 gallon dilution on December 15th at about 9:50 a.m. The inspector notes that the total RCS inventory in this condition is about 50,000 gallons, and the approximately 13,000 gallons of makeup water represents a significant reactivity addition to the core.

From a review of shutdown margin calculations (OST 1.49.2), it was determined that a minimum value of 1290 ppm boron was necessary to meet the reactivity technical specification. Considerable margin was still left.

Though no technical specification was apparently violated, the inspector raised a concern that the licensee's boron dilution procedure needed revision to reflect possible off-normal system conditions, to formally increase the chemistry sample frequency, and specify a limit for the total amount of makeup water added between samples. Corrective action in this regard is Unresolved Item (84-33-01).

2. Technical Specification 4.4.6.2.d requires the performance of a reactor coolant system water inventory balance at least once per 72 hours during study state operation when the reactor is in mode 1 - 4. This surveillance is performed under OST 1.6.2, RCS Water Inventory Balance, and requires RCS T-average to be maintained as stable as possible to obtain meaningful results. The Operations Supervisor informed the inspector that the plant was experiencing difficulty in maintaining a stable T-average, while in mode 3 because of the lack of decay heat or nuclear heat for startup with a new core. RCS pump heat is used to maintain the plant hot under this condition, and it is very difficult to match feed flow - steam flow for any length of time, which ultimately results in temperature fluctuations over the two hour test period that invalidates the test results. The Operations Supervisor stated that a necessary heat source would be achieved in mode 2 with the addition of nuclear heat, at which time the OST would be completed. The inspector found this to be acceptable. Subsequent review of RCS water inventories completed on December 26, 1984 and January 1, 1985, indicated that unidentified RCS leakage was essentially zero gpm.

3. A spurrious over-temperature delta-temperature (OTΔT) reactor trip occurred at 6:52 p.m. on December 23, 1984, while the reactor was in mode 4. All bistables associated with one power range monitor nuclear instrument (including the OTΔT and OPΔT) had been tripped for a monthly surveillance test. Concurrent with this activity, technicians were reinstalling low level amplifiers following a calibration crosscheck of the RTD instrumentation system. Upon reinstallation of one of the modules, a voltage spike initiated a temporary high delta-T indication on Loop 2 to make up the two out of three trip logic. At the time, only the B shutdown bank was withdrawn for RPI calibration checks. All systems functioned as expected and the inspector identified no concerns in this area.

4. The high-high bistable of containment pressure transmitter PT-LM-100C tripped on December 24, 1984. Investigation traced the reason for the trip to an electrical spike caused by actuation of the proportional band controller on pressurizer heater bank 3C. Apparently, electrical instrument lines for both PT-LM-100C and the proportional band controller run next to each other in the same cable tray. This was the first time that this problem occurred because the previous Fisher-Porter transmitters, which are of a heavy conductor type that is inherently insensitive to this noise, were replaced with a Barton Model No. 764, to meet equipment qualification commitments during the recent outage.

As a temporary fix, the proportional control card was pulled, leaving heater bank 3C with only its on/off function. The inspector verified that this action did not violate Technical Specification 3.4.4, which requires operability of pressurizer heaters with 150 KW output while in modes 1 thru 3.

Discussions with the I&C Supervisor indicated that when the proportional heater signal came on, a pulse of about 1/40th of a second duration always occurred, but was not seen by the older Fisher-Porter transmitters. Because the new Barton transmitters are of a different design, the licensee has been in contact with the vendor to work on a possible long term solution that could include the use of filters. The inspector had no further concerns on this item at this time.

5. During a Control Room tour on December 31, 1984, the inspector noted a sharp increase in steam generator (SG) water levels followed by an abrupt decrease, as indicated on Control Room charts. Discussions with the reactor operators indicated that a main steam safety valve (MSSV) on SG B and C had lifted. The plant was in mode 3 at the time of the event.

   Investigation revealed that all three SG atmospheric relief valves and the residual heat release valve were manually isolated to support plant heatup because of steam leaks. Except for the C steam generator's atmospheric relief the control room bench board valve controllers were caution tagged as required by administrative procedures.

   Primary system temperature had been controlled by the steam dump system. Just prior to the MSSVs lifting, the licensee prepared for a stroke test of the turbine trip and throttle valves. To support this evolution, it was necessary for the operator to close the main steam isolation valves, isolating the steam dump system. The operator did this under the belief that the untagged C atmospheric relief pressure controller was available to limit primary system temperature, which in turn, limits secondary pressure. After closure of the main steam isolation valves, RCS temperature quickly rose from 547 F to 554 F, at which point the MSSVs lifted, terminating the transient. The C atmospheric relief line was immediately unisolated.

Technical Specification 6.8, Procedures, and Regulatory Guide 1.33-1972, QA Program Requirements, Appendix A, require the implementation of administrative procedures for equipment control. Station Administrative Procedures, Chapter 4, and OM Chapter 48, Conduct of Operations, allow operations personnel to troubleshoot equipment malfunctions provided that valve or component lineup changes are documented to assure proper restoration. Additionally, use of a caution tag is required to flag any temporary or abnormal condition to operations personnel. The failure to caution tag the C steam generator atmospheric relief valve to indicate inoperability while it was temporarily isolated for heatup, is a Violation (84-33-02) that resulted in an unnecessary challenge to plant safety equipment.

6. Control room log entries noted difficulties in maintaining initial containment vacuum on December 23 - 26, 1984. Discussions with licensee personnel during the inspection exit meeting on January 7, 1985, indicated that the inleakage was was caused by a mispositioned one inch casing drain valve on the A outside recirculation spray pump. Because the plant was in mode 4, it appears that Technical Specification 3.6.1.1, Containment Integrity, was violated. Ongoing followup on this Unresolved Item (84-33-03) will be documented in special NRC Inspection Report 50-334/85-03.

7. Mode 1 conditions were established at 4:32 a.m. on January 5, 1985, after completion of the turbine overspeed trip test. Later, during power ascension activities at 5:45 p.m., RCCA F-10 was determined to be about 28 steps lower than the control bank counter as determined by primary voltage measurements. Technical Specification 3.1.3.1 requires all full length rods to be operable and in position within 12 steps corresponding to their respective group demand counter. The action statement allows power operation to continue with one inoperable rod provided thermal power is reduced to less than 75% within one hour and the power range monitors high neutron flux trip setpoint is reduced to less than 85%. Additionally, the licensee is required to determine the shutdown margin at least once per 12 hours and to perform a power distribution map from the moveable incore detectors to verify that the hot channel factors are within their limits within 72 hours.

   With the exception of the power distribution map, the inspector independently verified licensee adherence to the above action statements. Discussions with operations personnel indicated that a 40 hour soak time was being performed at 50% power to reach equalibrium conditions, in order to obtain a meaningful power distribution map. Licensee actions are currently acceptable.

c. Plant Security/Physical Protection

Implementation of the Physical Security Plan was observed in the areas listed in paragraph 3a above with regard to the following:

- Protected area barriers were not degraded;
- Isolation zones were clear;
- Persons and packages were checked prior to allowing entry into Protected Areas;
- Vehicles were properly searched and vehicle access to the Protected Area was in accordance with approved procedures;
- Security access controls to Vital Areas were being maintained and that persons in Vital Areas were properly authorized;
- Security posts were adequately manned, equipped and security personnel were alert and knowledgeable regarding position requirements, and that written procedures were available; and,
- Adequate lighting maintained.

No concerns were identified.

d. Radiation Controls

Radiation controls, including posting of radiation areas, the conditions of step-off pads, disposal of protective clothing, completion of Radiation Work Permits, compliance with Radiation Work Permits, personnel monitoring devices being worn, cleanliness of work areas, radiation control job coverage, area monitor operability (portable and permanent), area monitor calibration and personnel frisking procedures were observed on a sampling basis.

10 CFR 20.408, Reports of Personnel Monitoring on Termination of Work, requires the licensee to report an individual's exposure to radiation and radioactive materials, incurred during the period of employment or work assignment in the licensee's facility, within 30 days after the exposure has been determined or within 90 days after the date of termination, whichever is earlier.

NRC Inspection Report 50-334/83-30, dated January 31, 1984, discussed the review of an allegation concerning a contrator individual's termination radiation exposure report (see Detail 11.2). At that time, the licensee committed to take action to ensure that contractors provide timely notification of worker terminations so that the required reports are generated and transmitted in a timely manner. Inspection Report 50-334/84-15 documented a licensee identified violation in this area, whereby a record review identified a missed report for a contractor, whose employment at BVPS, Unit 1, was terminated prior to Inspection 83-30.

On December 18, 1984, the licensee determined that a termination radiation exposure report had not been submitted for another contractor employee who terminated employment at BVPS on July 27, 1984. This is a Violation (84-33-04) of 10 CFR 20.408 that is being cited per 10 CFR 2, Appendix C, because it could reasonably be expected to have been prevented by the licensee's corrective action for a previous violation.

e. Plant Housekeeping and Fire Protection

Plant housekeeping conditions including general cleanliness conditions and control of material to prevent fire hazards were observed in areas listed in paragraph 3a. Maintenance of fire barriers, fire barrier penetrations, and verification of posted fire watches in these areas was also observed.

During the inspection period, the licensee concluded the fourth refueling outage, which lasted 12 weeks. Tours through the PAB, Safeguards Building and Containment indicated the need for additional attention to cleanup of work sites. This concern was brought to the licensee's attention, and addressed at the inspection exit meeting. Followup will be provided during routine inspection activities.

4. Unit Startup after a Refueling Outage

A. Preparations for the plant startup during the fourth refueling outage were observed by the inspectors during December, 1984. These observations included walkdown of portions of ESF systems that were disturbed during the outage, and included the following systems:

- Auxiliary Feedwater System

- Emergency Power Systems, including emergency diesel generator and diesel auxiliary systems.

The following surveillance tests were witnessed to verify that they were accomplished in accordance with approved procedures, test crew personnel were adequately briefed, test prerequisites were satisfied, special test equipment was calibrated and that test data was acceptable.

- OST 1.1.4, CIA Train B, Isolation Test

- OST 1.2.1, Nuclear Power Range Channel Functional Test

- OST 1.11.14, Full Flow Safety Injection Test.

- OST 1.36.3, Emergency Diesel Generator No. 1, Auto Start Test with Safety Injection.

During the performance of OST 1.36.3, the inspector observed modification testing performed for DCP-042, Paralleling Capability of the No. 1 Emergency Diesel Generator with the 1A 4KV bus. The tests were correctly performed and the test data was reviewed satisfactorily.

During the performance of OST 1.36.4, the diesel generator load sequencer for motor control center MCCI-E2 failed to sequence onto the emergency bus. Operators verified that the relay was attempting to operate but the switch contacts did not close. This was later determined to be the result of dirty contacts in the No. 2 EDG load sequencer cabinet for MCCI-E2. The contacts were cleaned, but during the work, an electrician inadvertently contacted a hot lead on the switch causing a voltage spike which tripped the No. 2 Vital AC Bus. The bus was reenergized and the electrician continued work after the circut was de-energized. This similar problem, working in hot electrical panels, was the subject of previous inspector concerns as identified in Inspection Report 50-334/84-12 (Unresolved item 84-12-04). This problem was again discussed with licensee management. The need to insure that work on electrical equipment that could affect safety systems, be conducted in a de-energized condition, if possible, was emphasized.

B. Prior to initial criticality, which was achieved on January 1, 1985, portions of BVT 2.2.1, Initial Approach to Criticality, and sections of BVT 2.2.2, Core Design Verification, were observed by the inspectors on January 1 - 3, 1985. Selected prerequisites were verified. The procedures were updated to reflect changes made to the core as a result of the new fuel loading scheme (Cycle 5), and were conducted in accordance with TS limits for core physics testing, Section 3/4.10. No problems were observed. Further NRC technical review of startup physics testing is discussed in Inspection Report 50-334/85-01.

5. Equipment Qualification Modification

DCP 351 replaced approximately 35 instrument transmitters with environmentally qualified models during the fourth refueling outage. Of these, six were Barton 386 models that were replaced with newer 764 models. Included were three flow transmitters for the high head safety injection header flow to the reactor coolant cold legs (FT-SI-961, 962, 963), and three steam generator wide range level transmitters (LT-FW-477, 487, 497).

A. During performance of the OST 1.11.14, Full Flow Safety Injection Pump Test, used to verify operation of the SI hot and cold leg injection check valves and to crosscheck SI flow with design data through use of installed flow instrumentation, the three high head safety injection flow transmitters failed in mid range. To comply with commitments for meeting the requirements of 10 CFR 50.49, Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants, DLC must have an environmentally qualified flow transmitter to indicate safety injection flow during accident conditions. Because three spare flow transmitters were not available, the licensee opted to install an environmentally qualified one at FI-SI-943, which is located upstream of the boron injection tank (BIT). This transmitter would indicate total high head safety injection flow to the BIT which is then routed to the three reactor coolant loop cold legs. The Manager of Nuclear Safety informed the inspector that a letter clarifying their intent would be forwarded to NRR. Through discussions with the Licensing Project Manager (NRR), the inspector determined that this course of action was acceptable.

Inspector review of the control room emergency operating procedures verified that a revision has been incorporated that directs the operator to use the environmentally qualified instrument.

Through discussions with the General Manager, NECU, the inspector was informed that either the three failed transmitters would be decontaminated and sent to the vendor for a failure analysis, or a vendor's representative would be brought to the site to determine whether or not a Part 21 Report should be issued. Followup on this item, which is expected to be completed by January 11, 1985, is Open Item (84-33-05).

B. Prior to station acceptance of the three steam generator wide range level transmitters, operators noted an apparent reversed indication on all three. These transmitters, replaced on a one-for-one basis, had the high pressure and low pressure legs reversed. In discussing this with NECU personnel, the inspector was informed that an error occurred when Engineering directed that the reverse acting 386 models be replaced on a one-per-one basis with reverse acting 764 models. It was not recognized at that time that the high and low pressure ports for the 764s were constant whether the model is the reverse acting or direct acting type. This was counter to the design of the inplace 386s, where the reverse acting model internally switched ports.

With the instructions given by the Engineering Group, field personnel had no way of knowing that the transmitters were being hooked up backwards unless they physically traced the instrumentation tubing back to the steam generators. The licensee's representative informed the inspector that a review performed for the other instrument transmitters indicated that the problem was limited to the three reverse acting model 764s. Licensee action to insure that the Engineering design specifications are correctly reviewed prior to issuing installation instructions is Unresolved item (84-33-06).

6. Surveillance Activities

To ascertain that surveillance of safety-related systems or components is being conducted in accordance with license requirements, the inspector observed portions of selected tests to verify that:

The surveillance test procedure conforms to technical specification requirements.

Required administrative approvals and tagouts are obtained before initiating the test.

Testing is being accomplished by qualified personnel in accordance with an approved test procedure.

Required test instrumentation is calibrated.

LCOs are met.

The test data are accurate and complete. Selected test result data was independently reviewed to verify accuracy.

Independently verify the system was properly returned to service.

Test results meet technical specification requirements and test discrepancies are rectified.

The surveillance test was completed at the required frequency.

The following surveillance activities were observed:

1. OST 1.30.8, Auxiliary River Water System Test, conducted December 10, 1984.

2. TOP 84-29, Verification of Auxiliary Feedwater Valve (MOV-FW-151 A-F) Isolation Capabilities, conducted December 21, 1984.

OST 1.30.8, Auxiliary River Water System Test, is performed on an 18 month frequency to verify the ability of the auxiliary river water system to provide required cooling water to the reactor plant river water system. A note in the instruction section advises the operator that the running river water pump must be secured when Unit 2 blowdown is in service, because it cannot handle the volume of two running pumps. Toward the end of the procedure, there is a second note to remind the operator that if a running river water pump was secured, then it should be restarted. The inspector noted that this did not require a double verification for restoration of a safety system to its normal alignment. This was brought to the operator's attention and an operating manual deficiency notice was issued. A review of the completed tests indicated that a double verification was made for proper restoration of the river water system.

No other concerns were identified.

7. Maintenance and Modification Activities

The inspectors observed portions of selected maintenance and modification activities on safety-related systems and components to verify that those activities were being conducted in accordance with approved procedures, technical specifications and appropriate industrial codes and standards. The inspector conducted record reviews and direct observations to determine that:

-- Those activities did not violate a limiting condition for operation.

-- Redundant components were operable.

-- Required administrative approvals and tagouts had been obtained prior to initiating work.

-- Approved procedures were used or the activity was within the "skills of the trade."

-- The work was performed by qualified personnel.

-- The procedures used were adequate to control the activity.

-- Replacement parts and materials were properly certified.

-- Radiological controls were properly implemented when necessary.

-- Ignition/fire prevention controls were appropriate for the activity.

-- QC hold points were established where required and observed.

-- Equipment was properly tested before being returned to service.

-- An independent verification was conducted to verify that the equipment was properly returned to service.

The following activities were reviewed:

-- The inspectors periodically observed the continued retubing of the C component cooling water heat exchanger. As the A and B heat exchangers are operable, the licensee has met the requirements of TS 3.7.3.1 and system capabilities specified in Section 9.4 of the FSAR.

The inspectors noted that when the heat exchanger was lowered for tube removal, the instrumentation cabinets of the post-accident sampling system had to be disconnected and removed. During discussions with the Chemistry Supervisor, the inspector was informed that the system would be functionally tested by chemistry personnel to insure operability after restoration. No further concerns were identified in this area.

-- Through log reviews, the inspector noted several failures of a reactor trip breaker (Westinghouse DB-50s) to close. The design safety function of this breaker is to open. To ascertain that the problem would not impact this function, discussions were conducted with cognizant maintenance personnel. With the aid of a vendor representative, the problem was corrected by adjusting the gap between the undervoltage trip coil bars ear and the trip bar. This allowed the UV trip coil bar to reset without actuation of the trip bar, and did not interfere with the trip function. The inspector was informed that DCP-670 was under development to replace the existing UV coil with one that incorporated a counter. The purpose is to provide a mechanical count of trip actuations to trigger preventive maintenance, and incorporate other modifications to comply with the Salem ATWS upgrade. The breaker UV coil discussed above was subsequently tested successfully before startup in late December per Surveillance Procedure 1.04/1.05. The inspector had no further questions.

-- Records of the Reactor Vessel Level Indication System (RVLS) were reviewed to determine the status of system completion prior to startup. Required startup tests had been satisfactorily completed and the open items generated were such that system operability would not be impacted. Final system acceptance was contingent upon a final system calibration of the micro processor by Westinghouse, about 6 - 8 weeks after reactor startup, so that plant specific heatup data can be programmed into the system. No concerns were identified.

8. Allegation Followup

An allegation was received concerning adherence to radiation work permit requirements and industrial safety problems that occurred while removing scaffolding from containment on December 15, 1984. The main area of the concern was that Duquesne Light House and Yards Personnel were apparently not being held to the same radiation work (RWP) requirements that laborer personnel were, as specified in RWP 12754-01. The inspector reviewed the RWP and verified that both work groups were required to remove scaffolding from containment under the same radiological controls. Discussions with Maintenance and Radcon personnel indicated that several deviations from the RWP were observed among the House and Yards personnel. These deviations included items such as: (1) removing the protective covering from scaffolding over open grates while personnel were working below, and (2) removing scaffolding materials from various high radiation compartments in the containment prior to obtaining a smear to determine the contamination level. The inspector was informed that in each instance, the unacceptable work practice was stopped by radcon technicians. This is an example of a licensee identified problem that was corrected in the field. Based on discussions with Regional management, no further NRC action is planned.

The second concern raised was that egress from the containment personnel airlock was blocked with drums and scaffolding that were being temporarily stacked at the exit as they were removed from containment. The inspector discussed this with licensee management and stated that during outages, access to and from containment should not be blocked in a manner that could hinder the ability of the emergency squad to respond to personnel injuries and fires. Licensee corrective action to insure that personnel access pathways are always maintained during the next outage is Open Item 84-33-07.

9. Inoffice Review of Licensee Event Reports (LERs)

The inspector reviewed LERs submitted to the NRC:RI office to verify that the details of the event were clearly reported, including the accuracy of the description of cause and adequacy of corrective action. The inspector determined whether further information was required from the licensee, whether generic implications were indicated, and whether the event warranted onsite followup. The following LERs were reviewed:

- -- LER 84-06-01 Operation (Testing) Prohibited by Technical Specifications.
- -- LER 84-16 Seismic Instrumentation

LER 84-06-01 updates licensee action taken to return the No. 1 and 2 station batteries to operable status, and is further discussed in NRC Inspection Report 50-334/84-30.

10. Exit Interview

Meetings were held with senior facility management periodically during the course of this inspection to discuss the inspection scope and findings. A summary of inspection findings was further discussed with the licensee at the conclusion of the report period.