U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No. 50-334/85-27

Docket No. 50-334

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

Facility Name: Beaver Valley Power Station, Unit 1

Location: Shippingport, Pennsylvania

Dates: December 1 - 31, 1985

Inspectors: W. M. Troskoski, Senior Resident Inspector
A. A. Asars, Resident Inspector

Approved by: G. W. Meyer for A. E. Tripp, Chief, Reactor Projects Section 3A — 1/16/86 Date

Inspection Summary: Inspection No. 50-334/85-27 on December 1 - 31, 1985.

Areas Inspected: Routine inspections by the resident inspectors (71 hours) of licensee actions on previous inspection findings, plant operations, housekeeping, fire protection, LSA shipments, radiological controls, physical security, engineered safety features verification, maintenance activities, surveillance activities, reactor protection system items, and cold weather preparations.

Results: Several reactor protection system deficiencies were reviewed concerning the testing of the overtemperature delta temperature channels and the setpoint of the negative flux rate trip (Section 8).

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DETAILS

1. Persons Contacted

J. J. Carey, Vice President, Nuclear Group
R. J. Druga, Manager, Technical Services
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 Engr. & Constr. Unit

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

2. Plant Status

The plant operated at full power throughout the inspection period.

3. Followup on Outstanding Items

The NRC Outstanding Items (OI) List was reviewed with cognizant licensee personnel. Items selected by the inspector 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 was reviewed, and planned and completed licensee actions were discussed for those items reported below:

(Closed) Unresolved Item (84-24-01): Check process monitor response at low gamma energy levels. Previously, the licensee used only high energy sources (Cobalt 60 and Cesium 137) for calibration of monitors RM-VS-101B and RM-LW-104. The manufacturer's technical manual recommended that a Barium (Ba-133) source be used to validate the primary calibration curve at the low energy region. The licensee subsequently updated MSP 43.13, Rad Process Monitor RM-VS-101B Ventilation Gas - Calibration, and MSP 43.18, Rad Process Monitor RM-LW-104 Liquid Waste Effluent - Calibration, to include the low energy source. About 20 other MSPs still need to be updated prior to their next scheduled use. Inspector discussions with the procedures group indicated that appropriate steps were taken to prohibit the use of these procedures until the appropriate revisions are complete. The inspector had no further concerns and this item is closed.

(Closed) Unresolved Item (84-24-02): Check plateau curve for process monitor detectors. It was noted that MSP 43.13 did not require a plateau check to obtain the operating high voltage setting. Discussions with the licensee indicated that they do not perform primary calibrations with gas and liquids containing all of the isotopes of interest at the station because of the technical difficulties involved. Rather, the rad monitor vendor, Victoreen, maintains a primary calibrated detector for both gas and solid sources (Cobalt, Barium, etc.) to obtain the original detector efficiency curve. The

licensee sends their solid sources to Victoreen, who, in turn, performs a secondary check to obtain the high voltage range for transfer of calibration data. Additional steps to perform a plateau check for these monitors are therefore, not required.

A second concern noted that MSP 43.13 and 43.18 did not require the low energy discriminator setting to be determined. The inspector reviewed the latest revision to these procedures and verified that appropriate changes were made. The remaining MSPs are currently flagged to require these changes prior to their issuance for the next scheduled performance. This item is closed.

(Closed) Unresolved Item (85-02-05): Determine why the condensate pump recirc valve RK series instrument rack print did not reflect actual as-built plant conditions. This item was last reviewed in Inspection Report 334/85-06 and left open pending review of corrective actions recommended by the Technical Advisory Group. It was determined that the cause of the problem was due to: (1) an oversight by personnel performing the field work, and (2) a lack of management control over the design change and modification process for the non-safety related turbine plant that resulted in out-of-date prints (RK series). The licensee has updated the drawing and in the future, the Construction Group will use plant loop calibration procedures rather than generic calibration procedures. The loop calibration procedures are specific for each instrument and contain as-built drawings. In addition, the licensee has instructed Construction Startup Group personnel to isolate and clear any device which may be activated during calibration, regardless of whether it is in service or not. This item is closed.

(Open) Unresolved Item (85-11-01): This item concerns six (6) fire dampers located in the Cable Spreading Room (CS-1). These dampers initially had a 1.5 hour fire rating but were upgraded to a 3 hour rating during the first refueling outage in 1980. When the dampers were placed back into operation, the carbon dioxide lines to the damper blow-out release mechanism were inadvertently left capped. The licensee noted that conditions such as those described in IE Notice 83-41, Activation of Fire Suppression System Causing Inoperability of Safety Related Equipment, might require leaving some of the dampers disconnected from the blowout feature. During the licensee's evaluation of this issue, American Nuclear Insurers (ANI) issued a letter, dated September 9, 1985, addressing their concerns with the fire dampers. The letter stated that in 1975 a full discharge test was conducted in CS-1 with the affected six dampers arranged to trip on CO2 discharge. Based on the results of this test, ANI continues to recommend reinstallation of the trip mechanism for all six dampers. As a result of this recommendation, the licensee issued ECN 589 to revise release linkage arrangements on the six affected fire dampers. The licensee has completed the installation of all six release mechanisms. The post modification CO2 puff test has not yet been performed; this item will remain open pending positive puff testing of the dampers.

(Closed) Inspector Follow Item (85-13-03): Followup to determine the status of the wind speed and direction strip chart recorders and the availability of this data. Currently, the licensee utilizes two methods of monitoring the

wind speed and direction, a strip chart recorder and computer output. The strip chart recorders are an old model and replacement paper is difficult to obtain. In the interim period, the licensee is using paper with a different scale than the recorder, but there is a correct scale on the top of the recorder. The inspector compared the readings from both the strip chart recorder and the computer and verified that they were the same. Human factors deficiencies of this type have been independently identified by the control room design review for Beaver Valley, Unit 1. Resolution of these individual deficiencies are being tracked by the licensee. This item is considered closed.

(Closed) Inspector Follow Item (85-15-02): Confirm that the licensee has positive control at all times over the dosimetry issue booth. Previously, the inspector had found the TLD booth left unattended and unlocked during backshifts after the licensee implemented changes to the shift rad technician assignments. The licensee stated that the booth would be secured when unattended in the future. Through subsequent discussions with several rad technicians, the inspectors verified that they were knowledgeable of this requirement. Backshift tours found the booth locked at all times. This item is closed.

(Open) Inspector Follow Item (85-16-03): Followup on licensee's submittal of a schedule and method of pressure isolation verification in the RHR system and implementation into the testing program. This item concerns the RHR pump suction pressure isolation valves MOV-RH-700 and 701. The licensee has chosen the pressure monitoring technique described in the initial SER of June 29, 1982. One of these gate valves will be tested each refueling outage to assure that the valves adequately maintain redundant pressure isolation and system integrity. This test procedure and acceptance criteria will be developed and in place before the fifth refueling outage. This item remains open pending incorporation of MOV-RH-700 and 701 testing into the test program, and verification that test results are acceptable.

(Open) Inspector Follow Item (85-17-08): Incorporate special operating order for return of 4KV or 480 volt breakers to operation in OM procedures. OM Chapter 36, 4KV Station Service System, Figures and Tables, has been updated via Figure 36-24, Breaker Racking Methodology, to provide appropriate guidance for both 4KV and 480 Volt linestarters. The inspector noted that OM Chapter 1.37, 480 Volt Station Service System, has yet to be updated. This item remains open.

(Open) Violation (85-22-04): Failure to issue contractor radiation worker termination report. The licensee responded to this violation by letter dated December 16, 1985. This letter noted that past termination report problems were apparently limited to craft personnel and that actions taken at that time were successful in preventing a recurrence. The recent violation was determined to be due to miscommunication to the Dosimetry Lab regarding contractor personnel (a consultant and a security guard) which had been communicated in a different manner. The licensee committed to issuing a nuclear group directive to establish a uniform method of reporting radiation workers who termi-

nate employment at BVPS. Security personnel are now required to directly forward a Site Employee Status Report to the Dosimetry Laboratory on a routine basis. This item remains open pending review of the directive and security administrative controls over the Site Employee Status Reports.

(Open) Violation (85-22-01): Unauthorized operation of Unit 1/2 boundary isolation valves resulting in an unplanned release of radioactive liquid from BR-TK-7. The licensee responded to this violation by letter dated December 16, 1985. The immediate corrective action steps specified have been previously reviewed in NRC Inspection Reports 85-22 and 85-24. These actions were found to be satisfactory. To prevent further recurrence, the licensee reposted a clearance on all Unit 1 isolation and drain valves on cross-connect lines to Unit 2 and chain locked all potential effluent path valves closed except ball valves. For ball valves, the licensee intends to install a specially designed clamping device by January 31, 1986. The inspectors verified that the licensee has installed an additional dam at the east end of the south trench to prevent water leakage into Unit 2. Local postings were reviewed and found to be satisfactory. Additionally, Unit 1 operating flow schematics and Unit 1/2 interconnection drawings were reviewed for identification of potentially radioactive piping interconnections. All valves were verified closed and tagged. This item remains open pending verification that the installation of the clamping devices is completed by January 31, 1986.

4. 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 Rooms
-- Containment Building
-- Penetration Areas
-- Safeguards Areas
-- Various Switchgear Rooms/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)
-- 10CFR50.54(k), Control Room Manning Requirements
-- BVPS Site/Station Administrative Procedures (SAP)
-- BVPS Physical Security Plan (PSP)
-- Inspector Judgement

b. Operations

The inspector 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 4a.

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 inspector 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 tour of the Primary Auxiliary Building on December 5, 1985, the inspector noted that containment air lock door control panel was energized. Followup determined that OST 1.47.1, Containment Air Lock Door(s) Type B Leak Test, had been completed at about 4:00 a.m. that morning. The OST only requires the operator to notify the shift supervisor upon completion. It does not require de-energization of the control panels (power switches are located in the control room). The inspector reviewed Station Administrative Procedure 28, Reactor Containment Entry, and OM Chapter 1.47.4A, Reac-

tor Containment Access Control. Neither requires the air lock door to be de-energized when not in use. Technical Specification 6.12.2 requires high radiation areas where the intensity can be greater than 1,000 mrem/hour, to have locked doors to prevent unauthorized entry. The keys are required to be kept under the administrative control of the operations shift supervisor or a facility health physics supervisor. Though the various high radiation areas inside containment are under such controls, the licensee's program for total control over containment entries could be improved. Discussions with the operations supervisor indicated that appropriate procedure revisions would be made to require verification that the air lock door is de-energized when not in use. Review of this action is Unresolved Item (85-27-01).

2. The licensee declared the Beaver County, Pennsylvania, Offsite Emergency Notification System (ENS) inoperable at 12:40 a.m., on December 8, 1985, after the system failed a once per 12 hour test code check. The NRC Operations Center was notified of the condition within one hour. The problem was traced to the master code generator at the Beaver County Emergency Center transmission tower. The ENS was returned to service at 3:30 a.m. that morning after the problem disappeared during troubleshooting. The ENS again failed a test code check the next day. After technicians removed several electrical cards and cleaned contacts, no further problems were encountered. The inspector noted that the licensee entered this event into their Unit Off Normal reporting system to build a historical file.

   The Columbiana County, Ohio, ENS was declared out-of-service at 11:00 a.m., on December 31, 1985, after failing a radio test check. The licensee made appropriate notifications. Subsequent investigation determined that the radio used to signal the individual sirens would still have been able to properly function.

   Licensee actions were satisfactory.

3. During a review of the control room logs on December 26, 1985, the inspector noted two instances where operations personnel identified safety-related instrumentation with out-of-date calibration stickers. Charging pump 1A discharge pressure indicator CH-PI-151 was found due by December 22, 1985, while returning the pump to service following maintenance work on the lube oil system. Since the other two pumps were operable, restoration was delayed one day for I&C to complete calibration. Performance of OST 1.13.10A, Chemical Addition System Valve Position and Pump Operability Check - Train A, was also delayed because the flow indicator on the recirculation line to the chemical additional tank (FI-QS-107) was out of calibration. In each case, these were local indicators used during performance of a monthly surveillance test. Discussions with I&C personnel indicated that each calibration had been properly sched-

uled, but were delayed due to manpower constraints during this time of the year. The inspector toured the control room and verified that safety-related instrumentation had current calibration stickers. Since all remote instruments used during surveillance testing (OST, MSP, BVT) are referenced in the specific test, with calibration due dates, the inspector had no further concerns.

c. Plant Security/Physical Protection

Implementation of the Physical Security Plan was observed in the areas listed in paragraph 4a 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 the Protected Area;

-- 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 staffed and equipped, security personnel were alert and knowledgeable regarding position requirements, and that written procedures were available; and

-- Adequate lighting was maintained.

The inspector discussed site access authorization procedures for contractor personnel with the Director of Security to determine whether adequate background checks are performed. The inspector was informed that DLC audits the background checks of the contractor guard force, and incorporates background check requirements into their contract with Stone and Webster Engineering Corporation (the A-E and prime contractor). However, no audits have been performed by DLC on the background checks of these individuals. Followup to determine how the licensee ensures that the required background checks were performed for all personnel granted unescorted site access, is Unresolved Item (85-27-02).

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 the conditions of the 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.

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 4a. Maintenance of fire barriers, fire barrier penetrations, and verification of posted fire watches in these areas were also observed.

5. Engineered Safety Features (ESF) Verification

The operability of the Containment Depressurization System was verified during December 1985, by performing walkdowns of accessible portions that included the following as appropriate:

(1) System lineup procedures matched plant drawings and the as-built configuration.

(2) Equipment conditions were observed for items which might degrade performance. Hangers and supports were operable.

(3) The interior of breakers, electrical and instrumentation cabinets were inspected for debris, loose material, jumpers, etc.

(4) Instrumentation was properly valved in and functioning; and had current calibration dates.

(5) Valves were verified to be in the proper position with power available. Valve locking mechanisms were checked, where required.

No deficiencies were identified.

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:

a. The surveillance test procedure conforms to technical specification requirements.

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

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

d. Required test instrumentation is calibrated.

e. LCOs are met.

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

g. Independently verify the system was properly returned to service.

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

i. The surveillance test was completed at the required frequency.

The following in-progress tests were witnessed by the inspector:

-- MSP 6.39, T-RC422 Delta T-T average Protection Instrument Channel II Calibration, December 4, 1985.

-- MSP 2.06, Power Range Neutron Flux Channel NI-42, Quarterly Calibration, December 16, 1985.

-- OST 1.24.4, Steam Turbine Driven Auxiliary Feedwater Pump Test, December 24, 1985.

-- MSP 24.31, F-FW 496 Feedwater Flow Protection Instrumentation Channel IV Calibration, December 30, 1985.

No deficiencies were observed.

7. Reactor Plant Component Cooling Water System (CCR) Maintenance Activities

Maintenance activities associated with the B pump motor inboard bearing replacement and A heat exchanger tube cleaning were periodically observed by the inspector. Equipment control procedures were followed by station personnel and two CCR subsystems remained operable at all times per TS 3.7.3.1 requirements.

The B CCR pump was declared inoperable on November 1, 1985, after lube oil temperatures reached 205 F for the motor inside bearing. During the month of December, 1985, several attempts to identify and correct the root cause were unsuccessful as the lube oil temperature would quickly increase without showing signs of leveling off while running the motor uncoupled. Discussions with cognizant personnel indicated that the vendor had been contacted for support. High CCR pump and motor bearing temperatures have been a recurring problem at Beaver Valley since about 1980. Further review to identify the root cause of the apparent motor misalignment is Unresolved Item (85-27-03).

Asiatic clam shells (see IE Bulletin: 81-03), some vegetable matter and dead river shad were found in the A and C heat exchangers (CCR-E) during November and December, 1985. The maximum accumulation on the tube sheet (river water

side) amounted to about 15 gallons of shells in CCR-E-C, which appeared to be the one most susceptible. Periodic checks have also found a small amount on the river water strainers to the charging pump lube oil coolers. Other safety-related heat exchangers, such as the emergency diesel generators, have shown no discernible increase in the differential pressure across them.

Discussions with station management indicate that the fully grown shells are thought to have been transported by the river water pumps from the pump bays, as opposed to growing in the heat exchangers. The combination of growth in an inactive bay, and transport by revolving screens into the pump bays during the recent high river water conditions, are thought to be the major source. In addition to the routine heat exchanger performance checks, the licensee has sent divers into the pump bays to remove the silt and shells, and plans to dredge in front of the intake structure during the next refueling outage (May, 1986). These actions appear acceptable and the inspector had no further questions.

8. Reactor Protection System Items

a. Over Temperature - delta T Surveillance Testing

The inspector noted through a control room log review that difficulties were encountered during performance of MSP 6.20, Delta T - T Average Protection Instrumentation Channel I Test, Revision 15, on December 2, 1985. Initial discussions with I&C personnel indicated the monthly surveillance test found that electrical noise had caused the loop setpoints to change by about 50 mvdc. Troubleshooting found that the noise could be eliminated by placing the lead-lag module (TM-RC-412E) time bias switch in the "out" position, without effecting the validity of the test. Consequently, Field Revision 85-I-51 was approved for MSP 6.20.

The inspector discussed the Channel I noise phenomenon with the I&C supervisor and questioned why the field revision would not also be applicable to instrument channels 2 and 3. The inspector was informed that an incident report would be initiated to review this item. The licensee subsequently determined that the revision would be applicable to the other loops.

Discussions with I&C engineers revealed that the station had always found the 30 second lead setpoint (TS Table 2.2.1) at about 28 seconds, the lower end of the plus or minus 10% acceptance band (obtained from tech manual). Licensee discussions with Westinghouse, supplier of the 7100 Series Process Instrument System, identified a long standing deficiency in station procedures. Apparently, the 18 month calibration procedures (MSP 6.38 6.39, 6.40) were written to use only the lead-lag switches (2.8-.4) of the modules. This, when multiplied by 10, would bring the lead-lag [illegible]ts to 28 and 4.0 seconds, which was within the plus or minus 10% [illegible]mentation accuracy. To bring the lead setpoint to exactly 30 [illegible]nds, it is necessary to place the time bias switch in the TM-RC 412E module to off. Consequently, the 18 month MSPs were revised to require this on September 17, 1985.

During the month of September, 1985, the licensee experienced numerous over Temperature - delta T turbine runback alarm spikes, as discussed in detail 5 of NRC Inspection Report 334/85-20. As a result of this problem, DCP 695, Lag Compensation for RCS Delta T and T-average Summators, was performed in October, 1985, to wire two existing summator lag resistors into the circuit as required by the newer model Rosemount RTDs. When MSP 6.40 was run for post-modification testing, the licensee found that the lead time constant did not meet the acceptance criteria. Investigation found the time - bias circuit was not wired into the module. This was subsequently corrected and the test acceptance criteria met. Tests on the other two loops were then successfully completed, but the lead time constants for one was found at the lower end of its acceptance band.

The Loop 1 lead setpoint received further investigation during performance of the next monthly test (MSP 6.21), and the time bias switch was also found not wired in. These time-bias deficiencies existed since the 7100 series racks were installed and tested in about 1974. The first draft MSPs were prepared by Westinghouse prior to initial plant startup. Licensee corrective action is satisfactory.

b. Negative Flux Rate Trip Setpoints

The power range negative rate trip is provided to ensure that DNBR is maintained above 1.30 for a control rod drop accident. At high power levels, a single or multiple rod drop accident coupled with the automatic rod control system maintaining nuclear power equivalent to turbine power, could cause an unconservative local DNBR to exist. WCAP-10297, Dropped Rod Methodology for Negative Flux Rate Trip Plants, provides a generic verification that the DNB design basis is met for those instances of dropped rod(s) which do not result in a reactor trip due to the negative flux rate signal. For any case where the negative flux rate trip is activated, no DNB analysis is required because there is no return to power (the reactor trips, terminating the transient). Consequently, a limiting safety system setting of less than or equal to 5% of rated thermal power with a time constant of greater than or equal to 2.0 seconds is established by TS Table 2.2-1.

Westinghouse Technical Bulletin NSID-TB-85-13, dated May 28, 1985, noted that some plants have used an incorrect value to align their nuclear instrumentation system power range positive and negative rate trip bistables. The incorrect value resulted from a misinterpretation of that specified in the Plant Precautions, Limitations, and Setpoint document and the nuclear instrumentation system's technical manual alignment procedure. This is a concern because the flux rate trip setpoint is used in determining the maximum undetected dropped rod worth which must be considered in the DNB analysis. It was recommended that plants review their test procedure methodology to achieve the proper calibration for a 5% trip setpoint.

The licensee's initial review of the technical bulletin resulted in a request for clarification of the recommended action dated July 25, 1985. No action was taken to revise the test procedure used to set the negative rate trip setpoint. Apparently, the licensee was unable to satisfy themselves through several communications with Westinghouse, that the recommended action was correct until December 9, 1985. At that time, it was decided to modify the plant maintenance surveillance procedures to the technical bulletin's recommendation. It was noted that the limiting safety system setpoint in Table 2.2-1 was correct as is currently specified. The positive and negative rate trip setpoints on power range monitor NI-43 were reset on December 11, 1985. The remaining power range monitors were not reset until December 16, 1985, due to manpower availability, and to allow for a burn in time to build up a confidence level that spurious trips would not occur.

The inspector reviewed the procedure revisions and discussed them with the I&C engineer. The trip signal is induced by making an equivalent voltage step change of 105% to 100% on the lower PRM detector. The reactor protection system develops this pulse as a non-linear voltage signal with respect to time. Since it only develops about 66% of its final voltage at the end of 2.0 seconds, the licensee had selected this as the trip setpoint. Westinghouse instrumentation personnel apparently determined that this setpoint methodology was non-conservative with respect to instrument loop inaccuracies. Consequently, the MSPs were revised to account for those inaccuracies by setting the 2.0 second voltage level at 50%. The station is currently drafting a Licensee Event Report for this item.

FSAR Section 14.1.3. Rod Cluster Control Assembly Misalignment, discusses dropped full length assemblies and takes credit for the power range negative rate trip. However, the rod control system has been operated in the manual mode for the past two fuel cycles. The immediate concerns of possibly exceeding limits during a rod drop accident with the RCS in automatic have not been applicable at BVPS-1. However, final resolution did appear to be slow. The Manager of Technical Services acknowledged that concern. The inspector had no further questions at this time.

9. Cold Weather Preparation

The inspector reviewed the Cold Weather Log (OM Chapter 1.54.3) to ensure that the licensee is maintaining effective implementation of protective measures for extreme cold weather in compliance with the November 1, 1979, response to IE Bulletin 79-24. IEB 79-24 requires the licensee to provide adequate protection for safety-related process, instrument, and sampling lines to prevent freezing during extremely cold weather. In the response letter, the licensee stated that the Cold Weather Log lists all piping and equipment that requires such protection. The letter also states that the log is completed in October and the plant is winterized by either actuating heat tracing, placing localized heaters, or enclosing or covering areas normally exposed to the outside environment. During this inspection period, the licensee has

experienced various equipment difficulties as a result of inadequate cold weather protection. Typical examples are the discovery of de-energized heat trace circuits, piping with insulation removed, and frozen instrument lines. The licensee has stated that they will revise the Cold Weather Log to better meet the requirements of IEB 79-24. Review of the revision and implementation of the log is Unresolved Item (85-27-04).

During subsequent review of heat tracing annunciator panels, the inspector identified that the drawings of annunciator panels in OM Chapter 45, Table 45-3 did not correctly represent the actual plant configuration. Specifically, the actual arrangement of alarms on panel ANN-QS-01 differed from the drawing for 17 of 18 alarms. Verification that the heat tracing panels alarm light bulb covers are in the correct configuration and update of the OM Chapter tables are Inspector Follow Item (85-27-05).

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.