U.S. NUCLEAR REGULATORY COMMISSION
REGION I

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Report No. 50-334/85-16

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

Facility: Beaver Valley Power Station, Unit 1

Location: Shippingport, Pennsylvania

Dates: May 14 - June 17, 1985

Inspector: for G. W. Meyer 6/28/85
W. M. Troskoski, Senior Resident Inspector date

Approved by: for G. W. Meyer 6/28/85
L. E. Tripp, Chief, Reactor Projects Section date
Section 3A,

Inspection Summary: Inspection No. 50-334/85-16 on May 14 - June 17, 1985

Areas Inspected: Routine inspections by the resident inspector (121 hours) of licensee actions of previous inspection findings, plant operations, housekeeping, fire protection, radiological controls, physical security, engineered safety features verification, ECCS overpressure protection, surveillance activities, and related corrective maintenance, reactor coolant system RTD environmental qualification, review of selected safety issues, I&E Information Notices, and licensee event reports.

Results: No violations were identified.

The inspector identified two unresolved items concerning improper identification of annunciator wiring (Paragraph 3.b.(4)) and adequacy of the safety review prior to interchanging different temperature transmitter models (Section 7). Further, the inspector performed a one-time inspection of ECCS overpressure protection (Section 5), and reviewed a licensee identified violation for time interval between RPS response time tests (Section 10.b).

## 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
   J. V. Vassello, Manager, Nuclear Safety

   The inspector 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 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 were reviewed, and planned and completed licensee actions were discussed for those items reported below:

   (Closed) Inspector Follow Item (84-33-05): Determine whether three Barton transmitter failures are reportable per 10 CFR 21. The subject transmitters were returned to Barton and inspected by representatives from both Westinghouse and Duquesne Light. It was determined at that time that the failures were caused by hydraulic shock, which unseated the internal O-rings. The Barton Model 764 differential pressure transmitters have a range of 0 - 44 inches of water, and were supplied as environmentally qualified replacements for the Barton Model 386 transmitters, which have a range of 0 to 400 inches of water. The Model 386's had been mechanically ranged down to the 0 - 44 inch scale and contained a heavier bellows design which precluded the O-ring failure. The licensee subsequently concurred that the 764 model transmitter with its low range, was not designed to be used in the application of the High Head Safety Injection lines, and therefore, was a misapplication due to design error and not reportable under 10 CFR 21. DLC's review of other transmitters installed under DCP 351 and 306 indicated that they would not be subject to severe hydraulic shock. The failed flow transmitters FT-SI-961 thru 963 were removed from the electrical equipment qualification master list and replaced with FI-SI-940, a qualified Rosemount transmitter, which measures the total cold leg injection flow and is located outside of containment. The licensee's equipment qualification records were appropriately updated. The inspector had no further questions and this item is closed.

   (Closed) Unresolved Item (84-33-01): Review corrective action for RCS boron dilution involving (1) RCS loop partially drained or isolated and (2) significant volume changes. This item was opened to track corrective action to an event that resulted in an inadvertent boron dilution from 2380 ppm to 1620 ppm, which was below the 2000 ppm desired end point.

The cause of this event was operator error in failing to take into account off-normal volume conditions with the plant in other than Mode 1. Corrective action included the development of a new procedure, OM 1.7.4A.T, Off-Normal Blender Boration or Dilution for Shutdown Operation, that contained applicable guidance to operations personnel for the various RCS volumetric conditions encountered when the plant is shut down. It accounts for adequate shutdown margin calculation, minimum RCS flow, review of initial source range levels, review by the Nuclear Shift Operating Foreman or Nuclear Shift Supervisor, and chemistry resampling of the primary system boron concentration at the one-half way point. This comprehensive procedure adequately addresses the inspector's 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 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)
-- 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 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 are 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 were 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 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) Through a review of the Maintenance and Operations Subcommittee meeting of the Offsite Review Committee conducted on May 14, 1985, the inspector noted that the station intended to return the automatic rod control system (RCS) to service. Discussions with the Operations staff indicated that this would occur during the next outage of sufficient duration to allow recalibration of the various instrument channels associated with this system. Because this system has been operated in the manual mode for the past several years, the inspector reviewed the licensee's plans for placing it in service. Discussions with the Operations and Training Staff personnel indicated that relicensing training Module No. 5, which had just been completed in early June, 1985, reviewed the operational aspects of the RCS in the automatic mode with all licensed personnel. Additionally, the Emergency Operation Procedure Refresher Course, scheduled to begin in June, 1985, will have about one-half of the scenarios conducted with the system in automatic. The only remaining concern in this area will be the ability of the analog rod position indication system to accurately track the individual RCCA positions within the plus or minus 12 steps specified in the tech-

nical specifications. By running the reactor with the control system in manual and all rods out, this has not been a significant problem. With the RCS in automatic and the RCCA's located in a mid-plane position, greater attention to the TS action statements will be required by the operations staff.

(2) On May 30, 1985, Westinghouse issued a report to various licensees detailing the potential for system interaction between the flux mapping system and the seal cable due to seismic loads. Specifically, it is believed that a seismic event could cause the non-nuclear safety grade flux mapping system to rupture the Class 1 pressure boundary at the seal table, which is located inside containment. The consequences of a flux mapping system falling on the seal table have not been analyzed. In the report, Westinghouse stated that because of the large number of different flux mapping system designs, and the various load interactions which could be expected to occur, that sufficient information to evaluate the integrity of the guide tubes at the seal table was not available on a generic basis, and that a plant specific review is recommended. Followup on DLC's actions in this area is Inspector Follow Item (85-16-01).

(3) At about 10:55 a.m. on May 31, 1985, a minor gas release occurred inside the PAB while pressurizing part of the B seal water injection filter (CH-FL-4B) for return to service. Apparently, the low point drain valve, CH-306, had been left open. Ventilation monitor VS-101A increased from 600 to 6000 cpm. From this, the licensee calculated that the release was roughly equal to 4.5 E-2 mpc. Rad monitor VS-109 (SPING) indicated no increase above background. The inspector verified that the gaseous release records were updated to account for this event.

Review of the equipment clearance (492264) associated with CH-FL-4B indicated that it was properly marked to have CH-306 opened with the aide of maintenance personnel because this valve is located at the 722' level of the PAB, under a floor plug. Upon returning the system to normal alignment, the operator failed to follow the equipment clearance procedure and missed aligning this remotely located valve. The inspector followed the subsequent system hydro on June 3, 1985. The test was conducted without incident and the inspector had no further concerns.

(4) During a review of lit control room annunciators, the inspector noted that the reactor vessel head vent high pressure alarm had been changed from a red background plate to a green background plate, signifying a normally lit condition. This alarm had been in since startup because one of the system's Solenoid Operated Valves was not leak tight. Maintenance has been scheduled for the next time Mode 5 conditions are achieved. In discussing the reason for changing the alarm's designation, the shift supervisor informed the inspector that pulling the knife switch designated for this annun-

ciator failed to clear the alarm indicating that the switch was mislabeled. Followup to determine how the reactor vessel head vent high pressure alarm's knife switch was incorrectly identified when this design change was turned over to the station is an Unresolved Item (85-16-02).

(5) The licensee identified a leaking cell on Battery No. 4 during efforts to find the source of a battery ground alarm. Cell No. 45 had developed a crack about nine inches long and was slowly leaking electrolite. The battery was declared inoperable at 1:15 p.m., on June 10, 1985. Technical Specification 3.8.2.3, requires the licensee to return the inoperable battery back to service within 2 hours, or place the reactor in Hot Standby within the next 6 hours.

The inspector observed corrective maintenance activities which removed the defective cell from the active bank and left the disconnected cell (one of 60) in place for seismic support considerations. OST 1.39.1D, Weekly Station Battery Check - Battery No. 4, was then successfully performed to verify minimum voltage requirements.

Because the battery was more than 12 years old and visual signs of cell deterioration were evident, the inspector requested the licensee to verify that adequate capacity remained to fulfill the system's design intent. During a meeting with members of NECU, Plant Performance and Testing, Operations and Maintenance, test data obtained during the fourth refueling outage was reviewed. The licensee concluded that based on the results of this data as modified for the removal of one cell, the battery is fully operable. Replacement of both the No. 3 and No. 4 batteries is scheduled for about May, 1986, during the next refueling outage. With both voltage and capacity requirements met, the licensee appears to be in compliance with ANSI/IEEE 450-1980, IEEE Recommended Practice for Maintenance, Testing and Replacement of Large Lead Storage Batteries for Generating Stations. Any further licensee actions to replace the failed cell with a qualified spare will receive routine inspector followup.

c. <u>Plant Security/Physical Protection</u>

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

-- Adequate lighting was maintained.

No discrepancies were observed.

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.

No discrepancies were observed.

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. The inspector noted that increased housekeeping efforts on both the primary and secondary sides of the plant have resulted in good improvements.

f. Chemistry

Amendment No. 39 to the BVPS Unit 1 Facility Operating License requires DLC to implement the secondary water chemistry monitoring program to inhibit steam generator tube degradation. The Station Chemistry Manual is required to describe: the sampling schedule for critical parameters and control points for those parameters; identify the procedures used to measure the values of those parameters; procedures for the recording and management of data; procedures for defining corrective actions for off-control point chemistry conditions; procedures that identify those with the authority responsible for the interpretation of the data, and a sequence and timing of administrative events required to initiate corrective action. The inspector met with the Chemistry Supervisor to discuss the above items and to determine whether or not the plant receives periodic chemistry recommendation updates from Westinghouse, the NSSS. The inspector was informed that the station received a technical bulletin entitled "Westinghouse Guidelines for Secondary Water Chemistry," dated

May 2, 1985, which contained updated information for plants utilizing the all volatile treatment (AVT) process. The Chemistry Department is in the process of revising their program to implement these guidelines contingent upon completion of DCP 129, Steam Generator Blowdown System Modifications, scheduled for the end of June, 1985. It was expected that previous INPO concerns for requiring mandatory action levels for specified secondary chemistry parameters would also be implemented consistent with the objectives of the Westinghouse secondary water chemistry program. The inspector had no further concerns at this time.

4. Engineered Safety Features (ESF) Verification

The operability of the Fuel Pool Cooling System was verified on June 12, 1985, by performing a walkdown of accessible portions that included the following as appropriate:

a. System lineup procedures match plant drawings and the as-built configuration.

b. Equipment conditions were observed for items which might degrade performance. Hangers and supports are operable.

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

d. Instrumentation was properly valved in and functioning; and had current calibration dates.

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

The system was inspected to verify that no creditable failure mechanism was available to drain the spent fuel pool level below the top of the active fuel, either by line break or a siphoning effect due to a valve misalignment. The line that penetrates the fuel pool at the lowest elevation is the 10 inch fuel pool pump suction line. It is located at the 750' elevation, which is about 9 feet above the top of the fuel racks. Since this would be the lowest point that the pool could be drained, no unreviewed safety question exists with respect to a line break.

With respect to the refueling activities, when the fuel pool is cross-connected to the reactor cavity via the fuel transfer tube, the lowest level that the pool could be drained to due to a reactor cavity seal failure would be about 2.5 feet below the top of the fuel assemblies. However, the active fuel portion would still be covered by about 9 inches of water. Further discussions of this issue can be found in NRC Inspection Report 334/84-22, Detail 9, IE Bulletin 84-03, Refueling Cavity Water Seal Failure.

No concerns were identified.

5. Overpressure Protection of Emergency Core Cooling Systems

The resident inspector performed a one-time inspection involving those valves which isolate primary coolant from low pressure ECCS piping and components to verify that a number of past industry problems have been addressed by the BVPS Maintenance and Surveillance Programs.

Through a review of P&IDs (No. 8700-RM-155 A and B) of the Reactor Coolant System (RCS) and FSAR Figures identifying the Q breaks (Section 6), it was determined that the only systems that interface with the RCS and have a design pressure less than or equal to 70% of the RCS design pressure are: (1) the low head safety injection (LHSI), (2) residual heat removal, and (3) safety injection accumulator system.

a. The two LHSI pumps are located outside of containment. Discharge from both subsystems is into a common low pressure header (700 psig pipe), with a high pressure transition point (2485 psig) prior to the header isolation motor operated valve, MOV-SI-890C. This single high pressure line then penetrates containment, and branches off into the three RCS cold leg loops. Each loop contains two six inch Velan check valves in series to isolate primary system pressure from the line that runs outside of containment. These check valves, SI-10, 11, 12, 23, 24 and 25, are designated Event V valves. The inspector verified that the above system configuration was consistent with the model contained in NUREG/CR-2069, Summary Report on a Survey of Light Water Reactor Safety Systems. This configuration is presented as follows:

   RCS-CK-CK-I-MOV(NO)-H/L-PRV-MOV(NO)-CK-P,

   Where I is the containment penetration, H/L is the high pressure - low pressure interface, and PRV is a 3/4 inch pressure relief valve.

   Technical Specification 3.4.6.3, RCS Pressure Isolation Valves, incorporated leakrate testing requirements for the Event V valves into the BV-1 License by Order dated April 20, 1981. Surveillance testing, consistent with this TS, is conducted under OST 1.11.16, Leakage Testing RCS Pressure Isolation Valves, at any shutdown to Mode 5 for greater than 72 hours if not performed in the previous 9 months. NRC Inspection Report 334/85-02 identified a violation whereby OST 1.11.16 had been performed using pressures lower than the function maximum pressure differential without adjustment of the observed leakage, as required by ASME Section XI, IWV-3420 of the Code. The DLC response to this item (85-02-01) is contained in a letter dated April 3, 1985, and is further discussed in Inspection Report 334/85-12. Review of past test data by the inspector confirmed that the licensee has met the leak rate criteria for these valves.

   Inspector review of the maintenance history of the six Event V valves determined that SI-10, 11 and 12, have exhibited no problems since Unit 1 startup in 1976. SI-23 underwent a seal weld repair in 1978 and had

its seating surface relapped and die checked in 1980. SI-24 and 25 likewise had bonnet to body seal welds performed during the 1982 outage. During this outage, all six C58 Velan swing check valves were modified under DCP-442. The modification replaced the original disc with one featuring a pin welded to the back side of the disc to serve as an anti-rotational device. This was to preclude the binding that occurred between the anit-rotational stops on the old disc and the hanger, which resulted in valve leakage due to failure to seat properly. This effectively addressed the concerns of IE Information Notice 81-30, Velan Swing Check Valves.

Discussions with cognizant station personnel indicated that no routine maintenance is performed on these valves, as long as leak rate test results continue to be acceptable.

b. The RHR system for 3-Loop Westinghouse PWRs is separate from the LHSI, and is entirely within containment except for one 6 inch recirculation line to the RWST. This line is isolated from the RCS by two normally closed block valves and a normally closed and deenergized motor operated valve, with an intervening 3 inch pressure relief valve. Hence, this system contains no Event V configuration.

Since the RHR-RCS system interface is a low pressure - high pressure (600-2335 psig) one, the isolation valves have pressure isolation verification requirements as specified in ASME Section XI, endorsed by Technical Specification 4.0.5. The licensee is currently in the process of defining those requirements in a manner acceptable to the NRC staff. By letter dated March 7, 1985, NRR has granted relief for MOV-RH-720 A and B, but denied relief for MOV-RH-700 and 701. The licensee is currently required to submit a schedule and method to accomplish the pressure isolation verification testing by about June 12, 1985. After resolution of this licensing issue, verification that testing of MOV-RH-700 and 701 is incorporated into DLCs test program, and test results are acceptable, is Inspector Follow Item (85-16-03).

The inspector reviewed the maintenance history of the four isolation valves. From the period of April, 1976 thru June, 1985, the only corrective maintenance involved relapping the seat of MOV-RH-720B. This was in response to a seating leak problem at the end of Cycle 4, that slowly pressurized this run of pipe to about 550 psig. No overpressure events have occurred involving this system.

c. The SI accumulators are located inside containment, and are low pressure vessels (normal operating pressure is 600 psig) connected to the RCS via two series check valves for each loop, SI-48, 49, 50, 51, 52 and 53. Leak testing of these valves to IWV-3420 Code requirements has been committed to by the licensee. A violation related to testing methodology has been identified in NRC Inspection Report 334/85-02. In the response, dated April 3, 1985, DLC committed to review the methods of leak testing

Category A valves in the IST Program to ensure that such tests are conducted in full compliance to Subsection IWV-3420 of the Code. This item (85-02-01) is scheduled to be completed by October 1, 1985.

The only safety system to experience an overpressurization event at BVPS Unit 1 was a charging pump suction line, due to a discharge check valve failure. The pressure was from the operating charging pump, thru the common header and not from the RCS. Region I issued Immediate Action Letter 81-16, dated March 27, 1981, and updated by letter issued June 16, 1981. This resulted in the previously discussed modifications (DCP 442) to all three and six inch Velan swing check valves. The charging pump monthly surveillance tests (OST 1.7.4, 5 and 6) continue to verify check valve operability.

6. Surveillance Activities and Related Corrective Maintenance

Portions of selected tests or resultant corrective maintenance activities were witnessed by the inspector to verify that: (1) procedures conform to technical specification requirements, (2) any necessary administrative approvals and tagouts were obtained, (3) work was accomplished by qualified personnel, (4) LCOs were met, (5) test results met acceptance criteria, and (6) any post-maintenance testing ensured the components ability to meet performance objectives. Activities observed included:

-- OST 1.13.10A, Chemical Addition System Valve Position and Pump Operability Check, maintenance troubleshooting on May 16, 1985.

-- OST 1.11.2, LHSI Pump 1B Test, on May 22, 1985.

-- OST 1.30.5, River Water System Valve Test - B Header, post-maintenance valve retests on June 4, 1985.

-- Charging Pump 1C corrective maintenance on June 13 - 14, 1985.

a. During performance of OST 1.13.10A, on May 16, 1985, the 4A chemical addition pump (QS-P-4A) failed to initially start upon demand. The licensee declared the pump inoperable and entered the action of Technical Specification 4.6.2.3, which requires restoration of pump operability within 72 hours. The inspector observed the licensee's troubleshooting which identified the cause of the problem as being a poor connection of one electrical phase in the 480 Volt breaker, caused by misalignment. The right side of the breaker apparently stopped sliding about 1/4 inch prior to the left side. This was caused by interference from electrical cable which had become loose due to a plastic tie-connector dropping down. One cable showed evidence of a blemish but no cutting occurred. The licensee tied down the loose cable, reinserted the breaker and verified operability by bumping the pump.

QS-P-4A was last tested on about April 16, 1985, prior to the plant shutdown for the one week maintenance outage that ended May 6, 1985. When the licensee entered cold shutdown for this outage, all of the con-

tainment depressurization pumps were disabled per procedure to prevent an inadvertent containment spray down. The breakers were racked out and pulled to the disconnect position. Since no work was done on this system during the outage and the surveillance tests were current, operations personnel determined that it was only required to rack the breakers back in and verify that the pump indicating lights in the control room were energized. It is believed that the pump was inoperable from this time until the surveillance test. The Operations Supervisor informed the inspector that long term corrective actions would include bumping all equipment to prove operability after the breakers are racked back in. This is already being done for the 4KV motors. A check of the other components that were de-energized failed to identify a similiar problem. The inspector has no further concerns on this item.

b. During performance of OST 1.30.5, on June 3, 1985, MOV-RW-113C, one of the two river water valves from the A header to emergency diesel generator No. 1, failed to properly cycle on the first attempt. The valve was manually opened and closed, lubricated and successfully cycled five times without incident. After approximately 12 hours, the valve was again successfully cycled on June 4, 1985. Stroke times were equivalent to previous data.

c. Operators noted a lube oil leak on the C charging pump (CH-P-1C) during the week of June 10, 1985. After running the pump on June 17, 1985, the source of the leak was positively identified as coming from the inboard oil seal. The inspector observed the mechanics disassemble the seal to find that it had been installed backwards. The seal was reinstalled and CH-P-1C was put on line for over one week without further significant leakage.

   Through discussions with maintenance personnel, it was determined that the seal had been replaced in March, 1985. Apparently, post-maintenance testing failed to identify the problem because the pump was run for about 30 minutes per OST 1.7.6 before being shut down and placed in a standby condition. It takes about one hour in-service time before the leak develops as the oil heats up. This did not occur until it was first placed in service during the week of June 3, 1985, when it began to get progressively worse. Review of the Dresser Industry Pump manual showed the correct alignment of the oil seal. However, no step specifying this was placed in the corrective maintenance procedure used by the mechanics. Discussions with the Plant Manager indicated that an incident report would be initiated to track this action. The inspector had no further concerns at this time.

7. Reactor Coolant System RTD Environmental Qualification

10 CFR 50.49, Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants, requires licensees to establish a qualification program for equipment that is relied upon to remain functional during and following design basis events, and certain post-accident monitoring

equipment. Section (g) requires that a schedule be developed and implemented for either the qualification of existing equipment or its replacement. Section (l) further requires that replacement equipment must be qualified within the provisions of 10 CFR 50.49.

Regulatory Guide 1.84, Revision 1, Environmental Qualification of Certain Electrical Equipment Important to Safety for Nuclear Power Plants, Appendix A, identifies the Reactor Protection System (RPS) as being covered under the provisions of 10 CFR 50.49(b)(1); i.e., it must remain operable during and following design basis events. This applies to the narrow range RTD instruments which provide input to the OTDT function of the RPS.

Regulatory Guide 1.97, Revision 3, Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident, Table 3, PWR Variable, identifies the RCS hot and cold leg water temperature function, provided by the wide range RTDs at BVPS Unit 1, as being required post-accident monitoring equipment.

BVPS Unit 1 was licensed in 1976. Originally, both control and protection narrow range RTDs as well as the wide range RTDs (indication) were Sostman Model 11834B-1s, which were supplied through Westinghouse. About the time BVPS was licensed, Sostman went out of business and Westinghouse obtained Rosemount Model 176KFs as replacements. Each RTD model has been qualified per IEEE 323-1971, as documented in WCAP 9157, Environmental Qualification of Safety Related Class 1E Process Instrumentation. Since 1976, all of the originally installed Sostman RTD transmitters in the wide range protection channels have been replaced with the Rosemount spares. From an environmental qualification viewpoint, this is consistent with RG 1.89, Revision 1, which allows identical equipment to be used as a replacement when it was on hand as part of the utility's stock prior to February 22, 1983.

Discussions with cognizant engineers in NECU indicated that the environmental qualifications of the wide range Rosemounts to IEEE 323-1974 standards for exposure to high rad fields expected inside containment during a design basis accident had been justified for operation until the fifth refueling outage, scheduled for May, 1986. At that time, they will be changed out under DCP 351 with RDF models from Westinghouse. The inspector was informed that the RDFs were originally purchased in 1981, but were sent to Westinghouse for conduit seal work to upgrade environmental qualifications. The RDF models apparently arrived back at BVPS in late May 1985. The inspector has no concerns regarding the wide range RTD instruments.

The narrow range protection RTDs are all Rosemount models; the last Sostman was replaced during the fourth refueling outage under a maintenance work request. After plant startup in January, 1985, an abnormal number of spurious alarms were experienced from the OTDT protection channels. The licensee informed the inspector that it was initially believed that the cause of the spurious alarms was due to the quicker response time of the Rosemounts as opposed to the Sostman RTDs (0.5 seconds vs. 3.0 seconds). However, the inspector noted that the alarms were coming from both the B and C loops, and

only one RTD transmitter was replaced during the fourth refueling outage. Inspector Follow Item (85-12-05) remains open until the source of the spurious OTDT alarms can be more firmly determined.

Consideration is currently being given to changing the lag time constant in the OTDT circuits. The original Westinghouse design called for the RTD transmitters to have the 0.5 second response exhibited by the now installed Rosemounts. However, Westinghouse found that the original Sostman transmitters, which were ordered to the 0.5 second specification, actually responded with a 3.0 second delay. Since this occurred prior to implementation of 10 CFR 21, each affected licensee was notified by Westinghouse. To account for the increased delay of the Sostmans, modifications were made to the electronic modules to ensure the 4.0 second time response assumed in the safety analysis is met. Now that all of the Sostmans have been replaced at BVPS Unit 1, the licensee has informed the inspector that they wish to return the OTDT circuits to the original configuration in hope of cutting down on the number of spurious alarms.

Inspector discussions with the Instrument and Control Branch, NRR, raised the following questions:

-- What was the nature of the safety review conducted to ensure that the OTDT setpoint, as contained in TS Table 2.2-1, would not be affected by substituting Rosemount RTD transmitters in place of the originally installed Sostmans?

-- Since the OTDT setpoint equation in BVPS Unit 1 TS Table 2.2-1 contains only two time constants, and the more recent standard technical specification contain four such constants that are specific to a single model RTD transmitter, does the licensee intend to update this TS?

The Director of Nuclear Safety informed the inspector that Westinghouse has been contacted to analyze the effect of the specific transmitters on the setpoint, and that DLC is planning to submit a TS change request prior to changing the lag time constants. Followup to determine whether an adequate safety review was conducted prior to interchanging transmitters is Unresolved Item (85-16-04).

8. Review of Selected Safety Issues

The location of the manual trip circuit in Westinghouse designed solid state protection systems was reviewed to verify that the manual trip circuits are located downstream of output transistors Q3 and Q4 in the undervoltage output circuit. The inspector interviewed cognizant I&C personnel and reviewed controlled drawings contained in the vendor's manual, as attachments to MSPs, and in the I&C Department's Training Manual. The only place where electric schematic diagram 1082H41 could be located was in vendor manual No. 1.20-483A and the training manual. Each accurately reflected the location of Q3 and Q4 with respect to the manual trip function. As these appear to be the only such drawings, the inspector had no further questions.

9. I&E Information Notices

The inspector reviewed the licensing and compliance commitment action tracking system to verify that information notices issued from 1984 to date, have been received by the licensee, reviewed to determine whether or not the information was applicable to the station, and identify and complete any further actions that might be required. For the 94 information notices issued in 1984, the licensee's tracking system indicated that all were closed except for ten items still requiring additional action. Most information notices were reviewed and required action completed within about 45 days.

For 1985, approximately 40 information notices have been issued to date. Of these, only 18 have been entered into the licensee's tracking system with action completed on ten. Initial station review is still necessary for the remainder. The inspector also noted that NECU was responsible for followup action on about six items, some of which have been opened since July, 1984. The licensee's performance in this area appears to be slipping.

10. 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 85-07, Inoperable Hydraulic Snubbers.

-- LER 85-08*, Automatic Actuation of Reactor Protection System.

-- LER 85-09, Discrepancies in Reactor Trip Response Time Testing.

-- LER 85-10*, Reactor Trip Due to Low-Low Steam Generator Level.

*Discussed in NRC Inspection Report 334/85-12, Detail 3.b.

a. LER 85-07 reported the inoperability of two hydraulic snubbers on safety systems. Each failed a visual inspection in November 16, 1984, because their oil reservoirs were not located above the snubber valve block to ensure gravity feed to the seals. The snubbers were removed and functionally tested on November 30, 1984. Each failed to demonstrate lockup ability during this test. Prior to plant startup, the licensee performed the necessary corrective actions, which included relocating the remaining oil reservoirs to an elevation higher than the snubber seals.

   Through document review, the inspector determined that although OQC notified the station of the inoperable snubbers in two memos dated December 18, 1984 and March 27, 1985, an incident report was not requested until April 4, 1985. At Beaver Valley, incident reports (IRs) are the

administrative mechanism by which LERs are generated for submittal to the NRC. This IR was written on April 9, 1985. An engineering evaluation concluded that a design flow and not a service induced failure was responsible for the inability to lockup during functional testing. Therefore, an increased test frequency was not required per TS 3.7.14.

The LER was subsequently issued on May 24, 1985, six months after visual inspections identified a potential problem. Although the hardware was fixed in a timely manner, this is an example where the reportability reviews were not.

b. LER 85-09 discussed two concerns related to reactor trip response time testing: (1) OTDT channel response time in excess of UFSAR assumptions, and (2) incorrect staggering of logic train testing. For the first concern, the safety analysis assumed a 4.0 second upper limit on response to the OTDT function; but the technical specifications allowed 6.0 seconds, which included 2.0 seconds for transport and thermal lag delays inherent in the RTD bypass manifold. This is not consistent with the response time definition; that is the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until the loss of stationary gripper coil voltage. This error is present in the technical specifications for several Westinghouse plants and is being corrected by NRR on a generic basis. By letter dated April 23, 1985, DLC was requested to submit a TS change to address this issue.

In comparing all previous OTDT response time test data to the 4.0 second limit, the licensee determined that only TE 412 B, one of the original Sostman RTD transmitters, was out of specification at 5.2 seconds in the 1979 test. This RTD was replaced during the 1982 refueling outage with a Rosemount model for environmental qualification requirements. The licensee has been in compliance with the 4.0 second limit since then.

The second issue centers around proper test scheduling of the two logic trains. Technical Specification 4.3.1.1.3, requires the reactor trip system response time to be demonstrated within limits at least once per 18 months. Each test is to include at least one logic train such that both logic trains are tested at least once per 36 months and one channel per function such that all channels are tested at least once every N times 18 months where N is the total number of redundant channels in a specific reactor trip function as shown in Table 3.3-1. What the licensee did was to complete one cycle, starting with train A, finishing with train B, and then went into the next cycle starting with train B again. Hence, it was 54 months between train A tests.

The licensee identified violation was found by an internal audit requested by the I&C Department. The root cause was judged to be inadequate control of test scheduling. Because of the complex nature in ensuring that all channels are tested at the proper frequency over a test period that extends several years, the licensee developed BVT 1.3-1.1.8, Reactor Trip Time Responses. This BVT assimilates data from several

sources that includes reactor trip breaker time response tests, reactor trip and ESF logic time response (channel time), sensor response time data and gripper release times, to form a comprehensive picture that accurately reflects the time from when the parameter is exceeded at the sensor until the gripper coils open. Use of this BVT should preclude any recurrence of this problem.

The inspector further reviewed the incident with regard to the timeliness of LER issuance and resolution of identified safety problems. The original draft incident report (DIR 84-100) indicated that a noncompliance existed. The final incident report, issued on January 16, 1985, reversed that conclusion. It was during a review by the Onsite Safety Committee that this conclusion was challenged and the Licensing Group was formally asked for an interpretation. Their response to the OSC was dated April 29, 1985, and the LER was issued on May 23, 1985. It took almost six months from the time the question was first asked in DIR 84-100 on December 8, 1984, until the LER was submitted to the NRC. The inspector informed the licensee that greater efforts are necessary to ensure that questions raised by the incident report system are evaluated by the appropriate station group in a timely manner. That comment was acknowledged.

11. 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.