U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-334/85-20

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: September 1 - 30, 1985

Inspector: for J. E. Tripp 10/3/85
W. M. Troskoski, Senior Resident Inspector Date

Approved by: J. E. Tripp 10/3/85
L. E. Tripp, Chief, Reactor Projects Section 3A Date

Inspection Summary: Inspection No. 50-334/85-20 on September 1 - 30, 1985.

Areas Inspected: Routine inspections by the resident inspector (100 hours) of licensee actions of previous inspection findings, plant operations, housekeeping, fire protection, radiological controls, physical security, engineered safety features verification, reactor protection system OTDT trip, ESF equipment maintenance and testing, component cooling water heat exchanger repairs, emergency preparedness drill, monthly operating reports, and review of licensee event reports.

Results: Though no violation was issued, another example of a wrong security badge issue was identified by the licensee (Detail 3.c).

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

(Open) Violation (85-18-04): Protected Area access granted to individual with wrong picture badge. A second example of this problem is discussed in Detail 3.c of this report.

(Closed) IFI (85-12-05): Follow licensee actions to identify cause of spurious OTDT alarm. This item is discussed in Detail 5 of this report.

(Closed) Unresolved Item (85-16-04): Determine whether adequate safety review was conducted prior to RTD transmitter model changeout. This item is discussed in Detail 5 of this inspection report.

(Open) Unresolved Item (85-18-01): High steam pressure rate MSIV isolation requirements of TS Tables 3.3-3 and 4.3-2 are not consistent regarding surveillance testing. This item is updated as discussed in Detail 6.a of this report.

(Closed) Unresolved Item (84-12-05): Review CCR heat exchanger corrective actions. This item is closed out in Detail 7 of this report.

(Closed) IFI (85-12-03): Determine failure mode of component cooling water heat exchanger tube. This item is closed out in Detail 7 of this report.

(Closed) IFI (85-12-07): Review solution to recurring steam generator level trips during transfer of feedwater control from bypass to main control valves during plant startups. Procedure changes associated with this problem are detailed in Onsite Safety Committee Meeting Minutes BV-OSC-30-85. These changes and the reasoning prompting them were discussed with various licensed operators. Operating procedures now require that the primary side be stabilized with the main feedwater valves closed under manual control. Next, the steam generator levels are brought to a slightly higher than normal level via the bypass flow control valves. At this time, the main feedwater valves are placed in automatic control and the bypass flow control valves are manually bumped closed. The operators stated that this practice apparently worked well during the two reactor trip recoveries discussed in Detail 3.b of this report. This item is therefore 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 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 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) At the beginning of this inspection period the reactor was in Hot Standby (Mode 3), recovering from an inadvertent Safety Injection - Reactor Trip (see IR 334/85-18). Resulting equipment maintenance and related surveillance activities are discussed in Detail 6.a of this report. The inspector witnessed reactor startup on September 3, 1985. Full power was subsequently achieved on September 4, 1985, without event.

(2) The reactor operated at full power until a spurious Overtemperature - Delta Temperature (OTDT) trip occurred at 10:26 a.m., on September 16, 1985. The inspector was in the control room during the event, and observed operator action taken to stabilize the plant. All emergency systems functioned correctly. The cause of the trip was a momentary electrical short on vital bus II, which tripped the Loop 2 OTDT bistable with the Loop 3 bistables already tripped for surveillance testing. This completed the two out of three logic required for RPS actuation.

The cause of the short was traced to I&C surveillance testing of a wide range hydrogen analyzer recorder (H2R-HY 101). A poorly insulated shield cable contacted the recorder's power lead from vital bus II and shorted it to the chassis (this instrument loop measures changes in current rather than voltage). Heat shrink tubing was added to correctly insulate the shielded cable. A check of other similar recorders added as part of this TMI modification work package found no other similar deficiencies.

(3) The inspector observed reactor startup activities on September 16, 1985. An inverse multiplication plot was performed per previous commitments. Estimated critical position was calculated to be about 160 steps on control bank D. Actual critical position occurred earlier than expected; at about 186 steps on bank C with bank D fully inserted, which was within the minimum rod insertion limit found in TS Figure 3.1-1. The licensee informed the inspector that they believed the reason for this discrepancy was due to the quick decay of Xenon which peaked about 2 hours prior to criticality, and the RCS boron sampling error due to the delay in RCS mixing while diluting. The inspector had no further questions.

(4) On September 26, 1985, computer specialists replaced a power supply in the process variable computer (PVC) racks (DIN 3). When returned to service at 10:23 a.m., the P-250 process computer began reading the input from power range monitors NI 42 and 43 as about 20% lower than actual. This resulted in the erroneous logging of 62 penalty minutes for axial flux difference. The operators responded by manually logging delta flux every 30 minutes per TS 4.2.1.1.b.

At 11:20 a.m., the reactor operator noted that the individual rod position indicators (RPI) for all rods in control banks C and D were reading 200 steps instead of 228 and 225, respectively. The DIN-3 unit was de-energized at 11:25 a.m. and all delta flux and RPI indications returned to normal. Investigation revealed that a single analog input board was common to these instruments. The board was replaced and control room indications remained normal when the DIN-3 unit was re-energized. Since operability of the RPI system is required by TS 3.1.3.2, evaluation of the acceptability of the PVC design such that an internal failure could effect multiple control room indications, is Unresolved Item (85-20-01). Verification that the RPI failure is reported in the next monthly operating report (per TS 3.1.3.2(3)) is Inspector Follow Item (85-20-02).

(5) During the week of September 23, 1985, the control room received a trouble alarm for vital bus No. 3. During troubleshooting, the inverter was placed on a dummy load with vital bus supplied from its auxiliary source. During this time, the 500 amp inverter input fuse was accidentally blown during troubleshooting. The licensee replaced it with 400 amp fuse because stores had no available spares. The I&C supervisor stated that this was deemed acceptable as the normal load is 35 amps and the emergency load is 200 amps. The electrical technical specification (Section 3/4.8) addresses only the charger and the battery banks. The inspector observed the licensee subsequently replace the fuse with a qualified spare on September 27, 1985.

The 500 amp fuses are stock items that had a reorder level of zero. During the fuse replacement discussed above, a 3 amp instrumentation fuse was also accidentally blown. A review of the warehouse spare parts computer listing indicated that this item also had a reorder level of zero. The inspector expressed a concern that an actual plant emergency could be exasperated by a lack of qualified spare parts. Inspector Follow Item (85-20-03) will track licensee action to ensure that the stores department upgrades their administrative controls system to reorder emergency spare part stock items in a timely manner.

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 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.

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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 was 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 were also observed.

(1) The No. 1 diesel generator automatic fire suppression system was declared out of service on September 14, 1985. A solenoid operated valve failed during testing of a modification that would prevent an electrical short from erroneously firing the carbon dioxide system and disabling the diesels during a plant emergency. TS 3.7.14.3, Low Pressure Carbon Dioxide Systems, requires the establishment of a continuous fire watch within one hour, and submittal of a special report if not returned to operable status within 14 days. The inspector periodically verified that the continuous fire watch was established.

The failed SOV was replaced on September 26, 1985. Post maintenance testing witnessed by the inspector consisted of completing applicable portions of OST 1.33.9, Carbon Dioxide Fire Protection System Test, and OST 1.33.13, Fire Protection System Detection Instrumentation Test. The first actuation attempt failed and a thermostatic circuit trouble light illuminated at the local panel. After reset, the second attempt succeeded. A fire watch was maintained until the system was tested a third time. The inspector was informed that the reason for the first actuation failure was that the manual actuation button was not held in long enough for the circuit to pick up, hence the trouble light. The Operations Supervisor stated that for human factors considerations, a placard specifying required pick up time would be placed at the panel. The inspector had no further concerns.

(2) 10 CFR 50, Appendix R, Section III.G.2(e) requires structural steel forming a part of, or supporting fire barriers separating redundant trains to be protected to provide a fire resistance equivalent to that of the required barrier. TS 3.7.15, Fire Rated Assemblies,

requires fire barriers separating safety-related fire areas or portions of redundant systems necessary to achieve safe shutdown within a fire area, to be operable at all times. When such an assembly is considered inoperable, the licensee has the option of either (1) establishing a continuous fire watch or (2) verifying the operability of fire detectors on at least one side of the inoperable assembly and establishing an hourly fire watch patrol until the functional capability is restored.

During review of control room logs, the inspector noted that two separate fire patrols were being conducted in sections of the service building; once an hour for the cable mezzanine and once every four hours for the ESF switchgear rooms, process rack room, and control room air conditioning equipment room. The cable mezzanine patrols were initiated in February, 1985, when operability of the carbon dioxide system was unresolved. The operations supervisor stated that this patrol was left in effect because the structural steel issue is still unresolved. The inspector was also informed that the reason for the four hour fire patrol of the ESF switchgear room was to meet commitments contained in a DLC letter dated July 10, 1985. This letter discussed Appendix R fire protection commitments and exemptions granted by NRR letter of August 30, 1985. The structural steel exemption was denied at that time because it is to be addressed on a generic basis.

The inspector noted that the four hour commitment appeared to conflict with the one hour requirement already contained in TS 3.7.15. The licensee immediately increased the switchgear fire patrol frequency to once an hour. Further review indicated that security personnel perform a defacto fire watch in this area as part of their routine patrols. The inspector had no further concerns.

4. <u>Engineered Safety Features (ESF) Verification</u>

The operability of the Low Head Safety Injection System was verified during the week of September 23, 1985, by performing a walkdown 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.

During performance of the monthly surveillance test on September 25, 1985, the inspector verified that the wedge rod repairs to the low head safety injection pumps discussed in IR 334/85-18 remained leak tight. No discrepancies were identified.

5. Overtemperature - Delta Temperature Trip

Purpose

The Overtemperature - Delta Temperature (OTDT) reactor trip setpoint referenced in TS Table 2.2-1, is provided to prevent DNB for all combinations of reactor coolant system pressure, power, coolant temperature, and axial power distribution, provided that (1) the transient is slow with respect to transport delays and (2) pressure is within the range of the High and Low Pressure reactor trips. The OTDT trip setpoint takes the form of a Laplace transform containing specific time constants that are utilized in the lead - lag controller for T-average. Currently, there are several ongoing issues related to spurious alarms, changes in network response due to RTD model changeout, and its effects on the TS trip setpoint and response time limits. The inspector reviewed the current status of licensee actions as discussed below.

Spurious OTDT Alarms

After startup from the fourth refueling outage, the plant began experiencing numerous OTDT turbine runback and Delta-T alarms. Though these spurious alarms have occurred in all three loops, they were most prevalent in the C. Inspector Follow Item (85-12-05) was opened to track licensee corrective action.

Investigation revealed that the last protection channel Sostman RTD was replaced during the fourth refueling outage with a quicker responding Rosemount RTD, to complete environmental qualification commitments. Through discussions with I&C engineers, the inspector was informed that the T-average signal varies by about 1 F. The circuit's dynamic compensation of T-average amplifies this fluctuation by a factor of seven. When coupled with a random 2% fluctuation of the delta T signal, a 12% momentary variation in the OTDT setpoint is seen. Since the turbine runback is set at 109%, this results in a spurious alarm whenever the delta-T and T-average signals upper fluctuations are synchronous. This appears to be a reasonable explanation, as the alarms greatly diminish when reactor power is less than or equal to 98%.

RTD Replacement

The Solid State Protection System 7100 Series racks were shipped to Beaver Valley, Unit 1 with five resistors in the T-average and delta-T summators (TM-RC-422-J and K) that could be wired into the circuit to act as a filter, providing a one to five second lag. The RTDs were originally procured by Westinghouse from two suppliers; Sostman and Rosemount. It was expected that both models would have a response time of about 0.5 seconds. After the Sostman RTDs were installed at Beaver Valley, Unit 1, it was discovered that their response time approached 3.0 seconds. When coupled with the summator lag time, a possibility existed that the overall response could exceed 4.0 seconds (which excludes a 2.0 second margin for coolant transport and thermal lag). Consequently, Westinghouse informed the station by letter WIN 5581, dated December 21, 1977, that a two second lag should be installed when using Rosemount RTDs and a zero second lag when using a Sostman RTD.

Beaver Valley, Unit 1 preoperational and startup testing was conducted with Sostman RTDs and zero summator lag for all protection channels. Sostman stopped manufacturing RTDs in this time period and the only replacements available were the Rosemounts. From 1977 to date, as the RTDs failed, they were replaced on a one-for-one basis with the Rosemounts. These replacements were performed without modifying the summator lag values. The 18 month calibration and quarterly surveillance tests never identified a problem with the OTDT trip function as a result of this. Unresolved Item (85-16-04) was opened to determine whether an adequate safety review was conducted prior to replacing the Sostman RTDs with Rosemount RTDs. Since it appears that the RTD changeout has had a minimum effect on safety and a safety analysis was performed for DCP 695 (discussed below) to address the addition of the summator lag values, this item is closed.

DCP 695, Lag Compensation for RCS Delta-T and T-average Summators

The inspector reviewed the design concept dated August 28, 1985. The two design objectives are to: (1) wire in two of the five existing summator lag resistors, and (2) revise the OTDT and OPDT reactor trip setpoint equations of TS Table 2.2-1. The safety evaluation addressed the RPS response time to assure that the sum of the sensor, channel, reactor trip breaker delay and gripper coil release times were less than 4.0 seconds. The safety evaluation also noted that a TS change would be required. The DCP contained no further discussions on the nature of the proposed TS change.

The inspector discussed the proposed TS change with members of NECU, the Onsite Safety Committee and Licensing and Compliance. Because of the nature of the OTDT setpoint generation, the licensee stated that updating the BV equation that describes the trip to conform with the standard technical specifications or adjusting the time constants to rigorously reflect the behavior of each model RTD, constituted a clarification only. The original safety analysis addressed both model RTDs, and surveillance testing has verified that the critical parameter - time response to a step change in temperature, remained within the bounds assumed. Discussions with the Licensing Project Manager, NRR, confirmed that this approach was acceptable. Licensee actions regarding TS Table 2.2-1 update will be reviewed as Inspector Follow Item (85-20-04).

Response Time and Surveillance Testing

During the week of September 9, 1985, the inspector periodically reviewed the ongoing modification work being conducted under DCP 695. The inspector noted that MSP 1.15B-2, OTDT Time Response for Implementation of DCP 695, specified an overall response time of less than or equal to 3.0 seconds. Since the safety evaluation assigned a two second value assumed for RTD sensor response and filtering time and an additional two seconds delay time between the time the OTDT reactor trip setpoint is reached and the time the rods begin to fall, there appears to be an inconsistency with the three second time assigned per the DCP. Discussions with the I&C engineer indicated that the response time associated with the analog and logic circuits, trip breakers opening, and the tripper coil releasing, was less than 1.0 seconds and therefore, a response time of less the 3.0 seconds added to that was sufficient to meet the 4.0 second criteria assumed in the safety analysis. Actual analog response times for Loop C were about 0.9 seconds for a step change in T-average and 0.1 seconds for Delta T. Previous tests with the summator lag set at zero were about 0.6 seconds and 0.03 seconds respectively. This appears acceptable and the inspector had no further concerns.

At the conclusion of this inspection period, no other spurious OTDT alarms occurred for the modified loops. IFI 85-12-05 is therefore closed.

6. ESF Equipment Maintenance and Testing

a. Main Steam Isolation Valves

TS Requirements

TS 3.7.1.5 requires each main steam line isolation valve (MSIV) to be operable when the reactor is in Modes 1 thru 3. TS 3.3.2.1, ESF Actuation System Instrumentation, requires the ESF instrumentation channels that actuate the MSIVs to be operable with their trip setpoints consistent with the values shown in Table 3.3-4. From Table 3.3-3, ESF Actuation System Instrumentation, the steam line isolation function is required for (1) a low steam line pressure when the plant is operating in Modes 1 thru 3 (above the P-11 setpoint) and (2) a high steam pressure rate when the plant is in Modes 3 and 4 (this trip function is automatically bypassed above P-11, and is bypassed below P-11 when SI on low steam pressure is not manually bypassed). The inconsistency between the requirement for the ESF instrumentation actuation operability versus the MSIV hardware operability to perform this function was brought to the licensee's attention for correction and will be tracked along with those items previously discussed for Unresolved Item (85-18-01).

Surveillance Testing

The MSIVs are required to fully close within five seconds on any closure actuation signal while in Hot Standby with T-average greater than or equal to 515 F during each reactor shutdown, not to exceed once per 92 days. The inspector witnessed portions of these tests from both the control room and the main steam valve room on September 2, 1985. Both the B and C MSIVs exceeded the 5.0 second limit. Investigation revealed that the SOVs were functioning properly but that the actuator assemblies were apparently binding. The B MSIV was only about .5 seconds outside of its limit. A cracked brass yoke was replaced and the actuator assembly lubricated per the preventative maintenance procedure specification. The valve was satisfactorily retested.

The inspector and operations personnel noted that the C MSIV was only traveling about two-thirds closed. When the actuator linkage was disconnected, the flapper readily dropped indicating no internal valve damage. The inspector witnessed portions of the corrective maintenance which included changing out the B actuator after dismantling indicated that internal cylinder scoring had occurred. The cylinder was remachined and the valve successfully stroke tested at about 4.6 seconds on September 3, 1985. No reason for the cylinder scoring was identified by the licensee.

b. Turbine Driven Auxiliary Feedwater Pump (FW-P-2)

The FW-P-2 governor was changed out during the fourth refueling outage as part of the routine preventive maintenance program. After plant startup, auxiliary operators noted a difference between the actual governor speed setting and the value referenced in the station logs. Monthly surveillance test results indicated that the pump was operable and fully capable of performing its design function. To ensure the speed setting was correct, maintenance personnel contacted the governor vendor. The results of this discussion apparently led to some confusion caused by the governor vendor concerning the mechanical overspeed stop and the function of the governor to control the turbine speed up to the mechanical stop.

TOP 85-18, Determination of Turbine Driven Auxiliary Feed Pump Governor Setting, was written to empirically determine the governor setting for a high speed stop of 4758 rpm, which is below the 4830 rpm mechanical overspeed trip. The inspector reviewed the safety evaluation which concluded that no unreviewed safety question was involved because the setting is not referenced by technical specifications and the determination of the high speed stop was required due to changeout of the governor, which does not change the original design criteria. The original calculation had incorrectly assumed that a zero speed setting corresponded to zero rpm on the turbine speed. After the TOP was performed on August 6, 1985, which included performance of the monthly surveillance test, the speed setting was changed on August 9, 1985, to what was thought to be 4200 rpm rated speed without rerunning the pump to measure its true speed. During the next monthly OST performed on September 4, 1985, the shift supervisor noted that although the pump passed all of the TS acceptance criteria, it had a speed of about 4700 rpm. The inspector witnessed a retest on September 6, 1985, and in addition to the 4700 rpm pump speed, noted that the turbine's sentinel valve was lifting, which indicated an excessive discharge pressure (per the Terry Turbine vendor manual).

After contacting the turbine vendor, TOP 85-23, Turbine Driven Auxiliary Feedwater Pump Speed Adjustment, was developed to set the governor to maintain a nominal speed of 4200 rpm while maintaining the performance criteria specified in the TS. The inspector witnessed performance of this TOP and noted that after correcting the turbine speed to 4200 rpm, the turbine sentinel valve no longer lifted.

Although the original safety evaluation concluded that the governor speed setting could be changed without presenting an unreviewed safety question as it was not referred to in the technical specification, adequate post-maintenance testing would have indicated that an abnormal condition existed in the turbine. The primary cause of this problem was apparently due to faulty advice provided by the governor vendor. Licensee corrective actions were satisfactory.

7. Component Cooling Water Heat Exchangers (CCR-HX) - Allegation RI-84-A-0179

Region I received an allegation on December 10, 1984, concerning the size of the component cooling water heat exchanger (CCR-HX) tube holes. Much of this allegation had to be interpreted by NRC technical personnel because the citizen was not sure of the exact nature of the alleged problem. The purpose of this detail is to consolidate past inspection activities with regard to the work performed, the role of QC, and the post-repair tests and inspections.

Several small leaks were discovered on CCR-HX-1C on April 7, 1984, after mechanical tube cleaning. Eddy-current testing showed extensive tube pitting on the river water side (ID) of the tubes. Selected tubes were plugged and the remaining two heat exchangers were inspected. Unresolved Item (84-12-05) was opened to track investigation of other heat exchangers served by the river water system to determine whether they were subjected to the same failure mode.

NECU report of June 25, 1984, identified the tube degradation problem as being due to crevice corrosion caused by manganese deposits from river water. The licensee concluded that these pinhole leaks were of such a nature that a catastrophic tube failure was not considered likely. This report was forwarded to Region I for review by engineering specialists. A telecon was conducted on August 21, 1984, between the Region I specialists and licensee engineering representatives to clarify certain details of that report. All concerns were resolved at that time as documented in IR 334/84-20.

CCR-HX-1C was retubed beginning in May, 1984. During the 4th refueling outage, starting in mid-October, 1984, the A heat exchanger retubing work started. Difficulties were encountered during the retubing work due to support alignment problems, but the inspector was not able to identify any problems due to holes that were too big. After the alignment difficulties were resolved and retubing completed, leak testing observed by the inspector identified several pinhole leaks at the peripheral where the water box bolts to the tube sheet. Several weld repairs were conducted and a subsequent hydro test was observed by the inspector. Quality Control covered both the repair and testing. The allegation that there were "hundreds of holes that were too big for components" and the NRC assumption/interpretation that the allegation pertained to the A heat exchanger could not be substantiated. Based on the satisfactory completion of the hydro test, the heat exchanger was returned to service.

On April 2, 1985, the B heat exchanger was removed from service for mechanical tube cleaning. Three leaking tubes were identified at that time. While it was out of service for tube plugging and repair, the A heat exchanger developed a catastrophic tube failure on April 27, 1985, as indicated by a surge tank level decrease of approximately 1" every 15 - 20 minutes. The heat exchanger was isolated and the tube was plugged but not pulled at that time because of the immediate need for two CCR heat exchangers while cooling the plant down to Mode 5 conditions in preparation for maintenance activities. Inspector Follow Item (85-12-03) was opened to determine the cause of the tube failure. After the A heat exchanger was removed from service and the failed tube pulled and plugged, several additional small leaks on the tube to tube sheet cladding interface developed. Weld repairs were conducted and the inspector observed the final hydrostatic test on July 24, 1985 (see IR 334/85-17).

NECU Report dated September 9, 1985, indicated that light optical and scanning electron microscopy identified the tube failure mode as being reverse torsional fatigue. The fracture on the peripheral tube was located at the mid point of the overall tube length at the support plate. The X shaped characteristics of the tube fracture were determined to be similar to those expected for this type of fatigue failure. Subsequent eddy-current examination of the two outmost rows of tubes on the lower half of the A heat exchanger bundle identified no significant indications or wall thinning. This suggests that the problem is limited to the one failed tube. The licensee has recommended that the A heat exchanger be subjected to a shell side pressurization during the fifth refueling outage scheduled for mid-1986. IFI (85-12-03) is closed.

As of this report, CCR-HX-1B is scheduled for retubing during the next refueling outage. The inspector was informed by maintenance personnel that the results of inspections conducted during the last outage for other safety-related heat exchangers (diesel generator coolers, one recirculation spray heat exchanger) indicated that only minor tube pitting had occurred. Inspection of two additional recirculation spray heat exchangers and modification of the A and C charging pump lube oil coolers are scheduled for the 1986 outage. The inspector had no further concerns and Unresolved Item (84-12-05) is closed.

8. <u>Emergency Preparedness Drill</u>

The inspector participated in the Beaver Valley Annual Emergency Exercise conducted on September 19, 1985, as a member of the NRC's Regional Response Team. Licensee activities were observed from both the control room and the

Technical Support Center. During the drill, an actual fire occurred in the Turbine Building when the B station air compressor belts smoldered. The licensee quickly suspended the drill, assembled the fire brigade, and extinguished the belts. Instrument air pressure had dropped from 110 Lbs. to a minimum of 90 Lbs., before recovery. After the plant condition was stabilized and evaluated by the licensee, the drill was resumed. The NRC critique of the drill can be found in NRC Inspection Report 334/85-19. Licensee performance was considered strong.

9. Monthly Operating Reports

The inspector reviewed the report issued for the month of August, 1985, to verify that the information required by TS 6.9.1.6 was accurate. The inspector noted that the August 29, 1985, safety injection - reactor trip was reported only as a reactor trip due to a loss of instrument air. It did not refer to the declaration of an Unusual Event nor the safety injection involved. This was brought to the attention of the supervisor of testing and plant performance. The inspector was informed that the September, 1985, Operating Report would be annotated to corrected this omission. The inspector had no further questions.

10. 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 LER was reviewed:

LER: 85-13 provided details of a reactor trip on July 6, 1985, due to a low-low steam generator level. The initiating fault was identified as a Hagen V-TO-1 converter used in the steam pressure mode, that went into a continuous reset mode of operation. The corrective action relating to this was not discussed in the text of the LER. The inspector requested the licensee to issue a supplemental report detailing the corrective action. This is Inspector Follow Item (85-20-05).

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.