U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-334/86-18

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: August 1-27, 1986

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Inspection Summary: Inspection No. 50-334/86-18 on August 1-27, 1986

Areas Inspected: Routine inspections by the resident inspectors (400 hours) of licensee actions on previous inspection findings, outage activities, housekeeping, fire protection, radiological controls, physical security and allegation followup, outage surveillance testing, the CILRT, startup recovery, control of Design Change Package open items, miscellaneous safety issues and hydrogen recombiner modification testing.

Results: One violation was identified (failure to administratively control keys, detail 4.c). Outage recovery and startup activities were found to be well controlled. Cold shutdown plant configuration control over required systems and components met regulatory requirements, however, areas were identified where further improvements are needed (detail 7.b) in configuration control for other equipment.

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DETAILS

1. Persons Contacted

   During the report period, interviews and discussions were conducted with members of licensee management and staff as necessary to support inspection activities.

2. Plant Status

   Unit 1 completed its Fifth Refueling and Modification Outage and entered Mode 2 to conduct Hot Zero Power Physics Testing on August 23, 1986. A manual reactor trip was initiated from 3% power at about 1:05 p.m., on August 26, 1986, after the four control rod clusters associated with shutdown bank A, Group 2, dropped into the reactor. At the conclusion of this inspection period, the plant was operating at 30% power.

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 OIs 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) Unresolved Item (86-04-01): Determine cause of Vital Bus 3 circuit board terminal problems. During the course of this inspection period, several Vital Bus 3 power fuses were blown due to a mis-sequence firing of the thyristor. The licensee, with the aid of the Cyberex vendor representative, disassembled the No. 3 inverter and found evidence of arcing on the ground strip from the thyristor logic control board. The arcing occurred at a loose connection between the ground strip and the ground bus bar, which was subsequently tightened. Inspection of the No. 4 inverter also found evidence of minor arcing. The station is planning to modify the preventive maintenance program to provide for a refueling outage frequency check of these components. As this appears to have been the root cause of the inverter malfunction, this item is closed.

   (Closed) Unresolved Item (85-06-04): Develop 18 month OST test conduct program guidance. This item is discussed in detail 6 of this inspection report and is being administratively closed because of program changes and different concerns identified during the course of this inspection. Discussions with plant management indicated that significant portions of these procedures would be rewritten to incorporate lessons learned.

   (Closed) IFI (85-16-01): Determine whether a seismic event could cause the flux mapping system to rupture the seal table pressure boundary. Information Notice 85-45 detailed a design deficiency identified at another Westinghouse

NSSS facility. Because the exact configuration of these components are site specific, licensees were requested to perform an inspection of their system and perform any analysis necessary to verify that an adverse interaction would not take place during a design bases earthquake. The inspector reviewed EM 61558 which performed the seismic analysis. It concluded that, based on the BV-1 configuration, calculations showed that no interaction between the seal table and surrounding supports would occur. This item is closed.

(Closed) Unresolved Item (84-33-03): Investigate possible containment integrity violation during startup from Fourth Refueling Outage. Licensee corrective actions were confirmed during the augmented inspection discussed in detail 7 of this report.

(Closed) Unresolved Item (86-08-03): Use of parts from a non-safety component on a safety-related component without a 10 CFR 50.59 review. The component in question was a mechanical latch that was removed from a Category 2 motor generator set breaker and used in a Category 1 reactor trip breaker. Engineering Memorandum 61859 dated June 24, 1986, determined that the stop plate function can be considered non-safety-related as it does not impact the ability of the reactor trip breaker to open. This item is therefore closed.

(Closed) IFI (84-33-07): Verify maintenance of personnel access pathways during the Fifth Refueling Outage for the containment airlock. The inspector verified that these pathways were kept clear throughout the entire outage and especially during the high activity periods that included material removal for Type A testing and containment closeout. Licensee actions were satisfactory and this item is closed.

(Closed) IFI (86-05-06): In response to Generic Letter 84-12, DLC submitted a copy of their Process Control Program (PCP) to NRR for review. During this inspection report period, it was determined that DLC had developed another PCP which had not been submitted to NRR, and neither had the licensee performed evaluations to assure that vendor supplied data could be used to assure compliance with the regulations. By letter dated August 1, 1986, the revised PCP was submitted. Included in this submittal, were the results of the DLC Engineering section's independent review of the Atcor Supply data which was subsequently incorporated into the Beaver Valley, Unit 1 Operating Manual through the technical specification required review and approval process. This item is closed.

(Closed) Unresolved Item (84-18-01): Licensee to take corrective actions to ensure that reportable events are properly identified. This item was initiated because, for about one month, the licensee had been delinquent in preparing a required incident report on fire detection instrumentation test deficiencies. The inspector reviewed SAP Chapter 13, Preparation of Draft Incident Reports, Unit Off Normal Reports and Conduct of Critiques. The licensee has instituted a requirement for preparation of Unit Off Normal Reports (UONRs). These reports document off normal plant conditions or events which do not meet the criteria for an Incident Report yet are of a nature that they may be used for data collection and evaluation of plant occurrences. Since creation of the UONR, station personnel more closely evaluate abnormal plant conditions for reportability and therefore, are no longer likely to neglect preparation of the necessary reports. The inspectors continually review UONRs, Incident Reports and LERs and have found no further deficiencies.

4. Plant Operations

a. Outage Activities

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

The inspectors regularly verified compliance with NRC requirements and TS during operational mode changes and selected outage work activities. Included in these reviews were plant radiation monitors, nuclear instrumentation systems, onsite and offsite emergency power sources, control of boration and dilution flow paths, containment integrity and ventilation requirements, decay heat removal, and availability of necessary engineered safety features systems. 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.

During the course of the inspection, discussions were conducted with operators concerning 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, the inspector comments or questions resulting from these daily reviews were acceptably resolved by licensee personnel.

1. While heating the reactor coolant system to 160 F with pump heat on August 7, 1986, the licensee received a pressurizer safety valve tail pipe high temperature alarm and PRT high level alarm indicating leakby. Apparently, the pressurizer safety valve (RV-RC-551C) had indication of a bellows failure. The licensee subsequently cooled the plant down and drained the pressurizer to about 20% to replace the failed valve. Discussions with test personnel indicated that this valve had been sent offsite during the outage for the periodic testing required by TS 4.4.3. Followup to identify the cause of the RCS safety valve failure is Unresolved Item (86-18-01). It was replaced with a qualified spare manufactured by Target Rock. The inspector reviewed the test certificates to verify that the left setpoint had been set to the TS value of 2485 psig plus or minus 1%.

During subsequent plant heatup and pressurization to 2235 psig, an operations walkdown of the RCS identified a steam leak from the flange of RV-RC-551C. The plant cooled down and depressurized. The licensee found that the flexitallic gasket had been accidentally crimped during installation of the spare valve. After replacement, a second walkdown at operating temperature and pressure conditions confirmed satisfactory repair.

2. After experiencing several electrical problems with "A" train motors on August 5, 1986, and identifying an additional problem associated with starting the A reactor coolant pump, the licensee determined that the probable root cause was due to an inaccurate control room meter indication for the 1A 4KV Bus. The meter which normally reads 0 to 130 volts for the full range 4160 volt bus was found to be about 4 volts low. In addition, some of the pump relay overcurrent protection setpoints were found to be set in the low end of the band, which when coupled with the high inrush current needed to obtain the same power level at the lower voltage, resulted in the spurious trip. The relay protection setpoints were reset at the upper end of the band. The voltage meters were subsequently calibrated and are to be entered onto a periodic test schedule.

3. A spurious safety injection occurred during the No. 1 Diesel Generator Auto Load Test (OST 1.36.3) on August 8, 1986, with the reactor in Mode 5, that activated only Train B components. No water was injected into the reactor because the SI pumps had been previously disabled per procedure. The operator placed the SSPS switch for Train B in Test, while the SSPS multiplexer was in the A+B position for an unrelated reason. This resulted in multiple control room alarms, as the SSPS indication alternated between the two trains. The operator was erroneously directed to return the Mode switch to Operate which resulted in a Train B SI on low steam pressure due to the block not being reinstated.

   The SSPS was immediately reset. A critique of the event also identified a test deficiency in that OST 1.36.3 de-energized two closed valves from the RWST to the charging pump suction line that were part of the boron injection path. Procedures were revised to prevent recurrence.

4. During a tour of the Control Room on August 15, 1986, the inspector noted that I&C technicians had been instructed to insert dummy signals into the A steam generator narrow range level instrumentation system. This was being accomplished per OM 1.24.4T, Draining and Refilling Steam Generators, to lower conductivity prior to startup. It cautions that the steps used to insert the dummy signals cannot be performed when the plant is operating in Modes 1 or 2. A signed double verification of the restoration steps are provided. At the time of this evolution, the plant was in Mode 4 with reactor coolant temperature at 340 F.

Since the SG level instrumentation provides input to both the reactor protection system and ESF logic cabinets, the inspector questioned the use of a dummy signal that effectively bypassed this trip and ESF function. A review of Technical Specifications 3.3.1.1, Reactor Trip System Instrumentation, and TS 3.3.2.1, ESF Actuation System Instrumentation, indicated that the SG low-low level trip was required only in Modes 1 and 2; which is consistent with the OM procedure caution. However, Table 3.3-3, ESF Actuation, requires it to be operable in Modes 1 - 3. This inconsistency was brought to the licensee's attention so that either the OM procedure or TS table would be revised.

A second discrepancy was also discovered in Table 3.3-3. Item 7c, Safety Injection (Start Motor - Driven AFW Pumps), requires the AFW system to be operable for all SI initiating functions and requirements per Item 1 of the table. Item 1, SI and Feedwater Isolation, require all manual and automatic features to be operable when the plant is in Modes 1 - 4. This is more restrictive than TS 3.7.1.2, Auxiliary Feedwater System, which only requires the pumps to be operable in Modes 1 - 3. The licensee is also reviewing this item for possible revision.

Discussions with the Procedures Group indicated that OM 1.24.4T would be revised accordingly. Long term corrective action to strengthen the design change and modification system, which includes the use of dummy signals to instrumentation that does not have an installed bypass switch, is currently under way in the development of a Station Administrative Procedure. Review of these actions to assure that the plant is not placed outside of its design basis by use of jumpers, lifted leads or unanalyzed bypasses to RPS and ESF instrumentation, is Unresolved Item (86-18-02).

5. The inspectors observed portions of the reactor startup activities and core physics testing that started on August 24, 1986. While conducting this testing, four RCCAs, of Shutdown Bank A, Group 2, dropped into the reactor at 1300 hours on August 26, 1986. The reactor was manually tripped from about 3% power per the abnormal operating procedures. Probable cause was identified as a failed circuit card in the rod control system power cabinet. Shortly before the trip, a rod urgent alarm came in, signifying trouble with the rod control system. Before the operators could respond to clear the alarm condition, the four shutdown rods were observed to be at the rod bottom position. The plant was stabilized and appropriate ENS calls were made.

   After replacement of the suspect card (both stationary and moveable gripper regulator and firing cards), the plant was restarted at 2330 hours on August 26, 1986. At the conclusion of this inspection, the plant was operating at about 30% power and continuing with the startup test program.

6. While in Mode 2, a problem arose concerning the actual position of rod F2 which is in Control Bank A (CB"A"). CB"A" had been pulled to 228 steps (operational "full out" position) per the group step counters. The individual rod positions (RPI) for all rods in CB"A" were within plus or minus 12 steps per technical specifications except for rod F2. The licensee suspected that the RPI was the problem. To verify this, TOP 86-34 was performed. A visicorder was installed to monitor the stationary gripper coil voltage profile for CB"A", Group 1 rods (F2, B10, K14, P6) only. The object of the test was to withdraw these rods several steps to the "full out" position of 230 steps and compare the voltage profile from the visicorder traces. Vendor data had been provided which showed a unique inflection on the voltage profile for the stationary gripper coil when rods are at 230 steps. Only CB"A" Group 1 rods were moved during this test since the lift coil disconnect switches for CB"A" Group 2 rods were opened per the procedure.

   The inspector observed the performance of TOP 86-34. The voltage profile for all four rods was very similar with the noted unique inflection which indicated the rods were in the "full out" position of 230 steps. The RPI for rod F2 was recalibrated satisfactorily and was now within plus or minus 12 steps when compared to other rods in CB"A". All lift coil disconnect switches were returned to normal and the inspector considered these operations satisfactory.

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

Implementation of the Physical Security Plan was observed in various plant areas 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.

Security Allegation Followup

Region 1 received a letter claiming that a set of security keys are readily accessible and not adequately controlled by the station. It was stated that the keys were kept in a locker located in the Administration Building, and accessible to anyone with the building master key. Through discussions with security personnel, the Administration Building custodian, and inspection of various key lockers, the inspector determined that protected area and vital area security keys were not stored in this offsite location. The storage of any other keys is of no concern for meeting the requirements of 10 CFR 73, Physical Protection of Plants and Materials. No further inspection followup for this allegation is planned.

c. 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.

On July 29, 1986, NRC license examiners observed three individuals (one radcon and two maintenance technicians) obtain keys from the locker in the NSS office in the Control Room by turning the combination dial approximately one-quarter turn, removing the key and signing them out. They then closed the door and turned the combination dial approximately one-quarter turn in the opposite direction. There was no shift supervisor in the office at the time and a sign on the key locker clearly stated keys are to be given out only with supervisor approval. This item was passed on to the resident inspectors for further followup.

TS 6.12.2 requires that each high radiation area access be controlled by locked doors and that the keys shall be maintained under the administrative control of the shift supervisor on duty. The failure to do so as evidenced by station personnel's ready access to the key locker containing the high radiation area keys is a Violation (86-18-03).

During a tour of the PAB on August 11, 1986, the inspector found a posted high-radiation door to the 1B Boric Acid Storage Tank Cubicle, closed but unlocked. No one was present and the door was secured. Discussions held with the Radcon Supervisor indicated that this event would be reviewed with the Operations Department and that station controls would be strengthened. The inspector noted that the frequency of locked door tours were increased to twice per shift for the duration of the outage, and that the station's policy in regard to each individual's responsibility was reinforced and clearly posted at the NSS key locker. The inspector had no further concerns at this time.

d. Plant Housekeeping and Fire Protection

Plant housekeeping conditions including general cleanliness conditions and control of material to prevent fire hazards were observed in various areas during plant tours. Maintenance of fire barriers, fire barrier penetrations, and verification of posted fire watches in these areas was also observed.

No discrepancies were identified.

5. Containment Integrated Leak Rate Testing

a. Previous Testing

The last Containment Integrated Leak Rate Test (CILRT) was conducted on May 9-13, 1982, in accordance with BVT 1.1-1.47.2, Rev. 0. Two significant problems hampered the testing; an excessive leakage path into the River Water System through the Recirculation Spray heat exchangers and malfunction of the personnel airlock emergency access hatch equalizing valve which caused the airlock to become pressurized. Acceptable leak rate data was taken for a period of 24 hours. Using the Mass Point Analysis Method, a calculated leak rate at the 95% upper confidence level of 0.0375 weight percent per day was obtained.

b. CILRT Procedure Review

The inspector reviewed BVT 1.1-1.47.2, Rev. 2, Containment Integrated Leakage Rate Test, and verified technical adequacy and compliance with TS 3.6.1.2, 10 CFR 50, Appendix J, and ANSI N45.4-1972, Leakage Rate Testing for Containment Structures for Nuclear Power Reactors. The test procedure adequately provided the necessary prerequisite testing, system configurations, actual leak rate measurements, superimposed leak testing, radiation discharge permit for depressurization, and controls for return of equipment after testing. The inspector noted that the licensee has chosen to use the Bechtel Corporation Total Time Analysis method as described in Topical Report BN-TOP-1 Rev. 1, Testing Criteria for Integrated Leakage Rate Testing of Primary Containment Structures for Nuclear Power Plants. The report states that previous performance of this method has shown that the acceptability or unacceptability of the leak rate can be determined during the first four to six hours of the leak measurement portion of the test. The BVT provides for a 12 hour leak measurement period after which a determination will be made based on an overall review of test data as to whether the leak rate is satisfactory. This time may be shortened at the discretion of the lead test engineer.

c. Test Prerequisites

The inspectors reviewed the following CILRT prerequisite tests to ensure that in each case, the test was adequately performed with acceptable results and that any unacceptable conditions were repaired and accounted for prior to test commencement.

BVT 1.1-1.47.1, Verification of Structural Integrity of Containment Liner and Concrete Structure.

BVT 1.3-1.47.6, Containment Liner Bulge Monitoring.

BVT 1.3-1.47.4, Type B Leak Testing - Electrical Penetrations.

BVT 1.3-1.47.8, Type B Leak Test - Personnel Airlock

BVT 1.3-1.47.9, Type B Leak Test - Mechanical Penetrations

BVT 1.3-1.47.10, Type B Leak Test - Equipment Hatch Airlock.

BVT 1.3-1.47.11, Safety Injection and Charging System Containment Penetration Valve Integrity Test.

BVT 1.3-1.47.5, Type C Leak Test of Containment Isolation Valves.

BVT 1.3-2.24.7, Steam Generator Pressure Test.

BVT 1.3-1.13.4, Recirculation Spray Heat Exchanger Leak Detection Test.

BVT 1.47.1, Type B Leak Test - Personnel Airlock Door O-Ring Seals.

BVT 1.47.11, Type B Test - Equipment Hatch Airlock Door O-Ring Seals.

The inspector reviewed the instrument calibration records for the resistance temperature detectors (RTDs), dewcels, pressure detectors, and superimposed leak rate panel. All calibrations met the applicable accuracy requirements and were traceable to the National Bureau of Standards. During a tour of containment, the inspector verified that the sensors were positioned as required. No unacceptable conditions were identified.

BVT 1.3-1.47.6 was performed between May 23 and July 14, 1986, to monitor the existing bulges in the containment liner and to identify any new bulges. All bulges are measured and compared to the corresponding data from last outage. There are a total of 23 measurable bulges; no new ones were identified. Though the measurement data has not yet been compared to the previous data, the results will be included in the CILRT results report to the NRC.

Performance of BVT 1.1-1.47.1 revealed separation of the concrete (grouting) at the transition region between the dome and cylinder portions of the outside containment wall and two gouges in the transition region. The separations were identified between the following radial markings; R7 and R14, R18 and R24, R62 and R71. The gouges were identified at R11 and R66. Each gouge contained a small triangular section of wood which was used during initial construction. The wood appeared to have swelled and forced out the surrounding grouting. Engineering

Memorandum 61846 was issued to resolve the significance of the separation and gouges and their impact on CILRT. The evaluation concluded that these defects in the grouting are insignificant and will not affect the CILRT. The EM also specified instructions for repair of the separations and gouges at a later time. The inspector had no further questions.

The inspector verified that danger and caution tags were appropriately placed on plant equipment involved in the test as required by the test procedure and OM Chapter 48, Conduct of Operations. The inspector reviewed several equipment clearance permits and verified that appropriate measures were taken to prevent inadvertent pump and valve operation.

Performance of BVT 1.1-1.47.4 on the electrical penetrations provided acceptable results; the majority of the penetrations had leakages smaller than the detection capability of the measurement instruments. Only two penetrations were repaired and retested. The "O" ring leak check for penetration 7G (blind flange inside containment) showed an as found leakage of 28.5 SCCM. The "O" ring was replaced and subsequent leakages were acceptable. The leak test for penetration 13F identified a leakage of 308 SCCM. Repairs reduced this leak rate to 25.2 SCCM.

BVT 1.3-1.47.8 was conducted on 7/29 and 7/30. The first test of the personnel airlock indicated an excessive leak which required a limit switch adjustment on the outer door. Repairs were affected and a retest was successful (40.8 SCFD). Subsequent to the BVT, OST 1.47.1 was successfully performed.

During performance of BVT 1.3-1.47.11, the licensee was unable to pressurize penetration 13 due to excessive leakage through TV-FP-107. Several attempts to repair the valve before the CILRT were unsuccessful. For the CILRT the spectacle flange immediately downstream of the valve was turned to serve as a blank flange and the associated drain valve was isolated. The inboard containment isolation valve is a check valve with an as found leakage of 0.436 SCFD. This leakage was used as the Type C penalty added to the total measured leak rate of the Type A test.

d. <u>CILRT Performance</u>

During the course of the test, the inspectors observed the final containment close-out walkdown, data gathering and trending, leakage rate calculations, superimposed leakage test, and performed independent hand calculations of the leak rate using available raw data. The following chronology summarizes the sequence of events:

July 30, 1986

0230	Completed close-out inspection of containment
0630	Began containment pressurization
2200	Ctmt recirc fan VS-F-1A tripped, started VS-F-1C
2230	Completed containment pressurization to 55.373 psia, at 78.85 F.
2300	Began stabilization hold

July 31, 1986

0304	Completed stabilization period
0337	Commenced leak rate measurement 55.180 psia, 76.875 F
0934	Suspected leak at Recirc Spray HX to River Water system isolated at HX river water discharge valves MOV-RW-105A, B & C.
	Increasing trend in containment moisture content

August 1, 1986

0516	Initiated leak rate measurement 55.335 PSIA, 77.364 F
1516	Leak rate unsat., fan chillers still affecting temperature
1610	Continued adjusting chilled water flow to fans
1700	Chiller adjustment unsat., temp still increasing
2351	Isolate chilled water and secured fans

August 2, 1986

0100	Ctmt temp and pressure stabilized 55.373 PSIA, 77.935 F
0237	Reinitiated leak rate measurement 55.372 PSIA, 77.871 F
1317	Completed leak rate measurement 55.359 PSIA, 77.909 F
1618	Began superimposed leak rate test, 4.6 SCFM

August 3, 1986

0035 Completed superimposed leak rate test, 4.6 SCFM

0235 Began depressurization

1113 Completed depressurization

During the course of the test, the inspectors observed the response of the containment wide range pressure indicators and recorders (PR-LM100A, PR-LM101, PI-LM-101A and PI-LM-101B) which were installed as a result of the TMI Action Plan Requirements. The sensors and recorders closely tracked the containment pressure as indicated by test instrumentation. Two items of information were noteworthy concerning the operation of the Containment Recirculation Fans. These are the fan blade pitch setting and the fan motor overcurrent condition while at test pressure of 55 PSIA. A test prerequisite was to adjust the fan blade pitch for all fans from the normal setting of 13 degrees to 7 degrees to prevent overloading the motor due to the denser containment air at test conditions. The 7 degree setting appeared to work satisfactorily in the last CILRT. The fan blade adjustment was done by the vendor (Joy). However, the fan motors operated in an overload condition for an extended time while at test pressure which indicates that future CILRTs should make further adjustments to blade pitch. In the early stages of the test (on 7/30) while initially approaching test pressure with two fans operating, VS-F-1A tripped on overcurrent. The third unit (VS-F-1C) was started without incident. The fan switchover had a minimal impact on the test.

e. CILRT Results

The inspector independently calculated leakage rates using raw data during the test to verify licensee preliminary leak rate estimates. The results of these calculations closely agreed with the licensee's results.

The test acceptance criteria required that the measured leak rate (including the upper 95% confidence level) plus the penalty leakage at the initial test pressure (53 PSIA) be less than 75% of the maximum allowable leak rate of 0.10 weight percent per day.

Using the total time method of leak rate calculation, the licensee determined that measured leak rate with the 95% confidence level to be 0.012761 percent per day and the penalty leakage from the Type C testing to be 0.001496 percent per day. These two values yield a total as found leak rate of 0.014257 percent per day. These results are well within the acceptance criteria.

The inspectors noted that TV-FP-107 was repaired after the CILRT and subsequently passed the Type C test. The leakage through this valve does not affect the as-found leak rate because the total penetration leak rates takes into account the isolation valve with the least leakage. In the case of TV-FP-107, the inboard check valve had the smaller leak rate.

The inspectors identified no further concerns.

6. Outage Test Procedure Review

a. Beaver Valley Tests (BVTs)

BVTs are governed by Station Administrative Procedure (SAP) 5b, Test Group and Testing and Plant Performance Administrative Procedures (TPPs). Specifically, TPP 5.1, Administrative Guidelines for Performing Tests, and TPP 6.1, Guidelines for Completing Test Results Reports (TRR), are applicable to the actual performance and approval of BVTs. The inspector noted that TPP 5.1 adequately provides for the notation of test deficiencies and deviations and NSS notification for immediate resolution. Also, the TRRs are structured so that a BVT cannot be approved if the test results are unsatisfactory. If the results do not meet the acceptance criteria, the deviation is identified and corrected; the test is reperformed until the results are satisfactory. Each BVT TRR is reviewed by two additional reviewers other than the lead test engineer. The inspector reviewed the following BVTs to ensure that these administrative controls are being effectively implemented to assure each test is performed with acceptable results.

BVT 1.3-1.47.1, Rev. 5, Containment Isolation Valve Leakage Test Connection Verification.

BVT 1.4-1.30.2, Rev. 0, IST Exercising of (River Water) Check Va ves RW-197 and RW-198.

BVT 1.4-1.13.5, Rev. 2, Inside Recirculation Spray Pump Test.

BVT 1.1-1.46.3, Rev. 0, Wide Range Hydrogen Monitoring System Leak Test.

BVT 1.5-1.33.7, Rev. 0, Halon System Nozzle Air Flow Test.

BVT 1.1-1.39.3, Rev. 1, No. 3 Station Battery Charger Load Test and Battery Service Test.

BVT 1.4-1.39.7, Rev. 0, No. 2 Station Battery Capacity Test.

No discrepancies were identified.

b. Maintenance Surveillance Procedures (MSPs)

A review of completed 18 month MSPs was performed to verify proper licensee review and approval, conformance to technical specifications, accuracy, completeness and resolution of test discrepancies. A sample size of 20 MSPs were chosen from the Main Steam, Main Feedwater and Auxiliary Feedwater Systems. The inspector noted that these procedures were clearly written in a good format and easily followed. Critique sheets provided a positive method of feedback and resulted in procedural changes when applicable. One minor weakness noted was that some procedures stated that they could be performed in any plant mode; however, this is not true for all steps of the procedure. The steps that cannot be performed are crossed out or changed by the technician performing the surveillance test. This item was discussed with plant management to determine whether prior supervisory approval should be obtained rather than leaving it to the discretion of the technician performing the test.

The inspector also reviewed MSP 4.03, ESF and Miscellaneous Safety Related Instrument Valve Alignment and Calibration Verification, completed August 5, 1986. The implementation of this procedure indicates that BV-1 has learned from other station's problems and implemented strong controls to assure proper instrumentation valve lineups prior to startup. This is a good practice.

c. Operation Surveillance Tests (OSTs)

The overall quality of the completed 18 month OSTs reviewed was found to be acceptable. General observation and minor problems identified by the inspectors are as follows:

(1) Several examples were found where it was difficult to determine whether or not the specified acceptance criteria was met. OST 1.11.15 requires the safety injection accumulator check valve to stroke fully open as verified in Step 22. This step states "have test crew verify the following check valves fully open" and lists the six valve numbers. There is no position indication on these valves. During inspector observation of the OST, the check valves were easily verified to have fully opened by the sound of the flapper banging on the seat.

A second example is OST 1.30.8, where the acceptance criteria requires the Auxiliary River Water Subsystem to provide at least 8000 gpm cooling water for at least two hours. The flow rate is established to an orifice, pump current and pump discharge pressure data are taken, and then the system is realigned to obtain the same pump discharge pressure. The acceptance criteria is then taken to be no degradation of monitor parameters over the two hour run.

Also, a precaution step required that two component cooling water heat exchangers must be available and utilized, but the shift supervisor noted that only one heat exchanger was available due to the outlet valve inoperability on CC-E-1C. The inspector questioned whether this affected the 8000 gpm acceptance criteria necessary for successful test completion. The licensee stated that the flow path used was chosen for operating flexibility and did not impact test acceptability. An OMCN was subsequently issued to clarify this.

(2) Some of the precautions and limitations could be worded more usefully in that quantitative values could be given for specified parameters such as recommended by ANS 3.2.

(3) A third general weakness identified on several OSTs was the pretest requirements to have "all valves in designated NSA positions as determined by Control Room logs or flow diagrams." The many instances identified by the inspectors where the Control Room logs and flow diagrams contained discrepancies from actual alignments (as discussed in detail 7.b of this inspection report), indicates that this is not a good practice. The licensee stated that all such references would be revised to specifically list the required alignment prior to the next refueling outage.

Major 18 month surveillance tests witnessed by the inspectors to verify procedure compliance and that test methodology met the intent of the technical specifications, included the following:

OST 1.24.8, Auxiliary Feedwater Check Valve Test, conducted on August 9, 1986.

OST 1.36.4, No. 2 Emergency Diesel Generator Load Test, conducted on August 10, 1986.

OST 1.11.16, Leakage Testing RCS Pressure Isolation Valve, conducted on August 11, 1986.

OST 1.7.11, CHS and SIS Operability Test, conducted on August 11, 1986.

OST 1.1.4, Containment Isolation Trip Test, Train B, conducted on August 8, 1986.

BVT 1.3-1.11.1, SI Auto/Manual Switchover to Recirculation Mode Operability Test, conducted on August 8, 1986.

No problems were identified by the inspectors during conduct of the above tests.

7. Outage Recovery

An augmented inspection of the Station Outage Recovery was conducted from August 8 thru 18, 1986, as recommended by the Region 1 SALP Board (See IR 334/85-99, Page 31). The inspection included extensive backshift coverage and focused on the conduct of control room activities, plant configuration control and completion of startup prerequisites. Additionally, licensee actions outlined in DLC letter of April 11, 1985, in response to the Notice of Violation (See IR 334/85-03 and NRC letter dated March 19, 1985) were extensively reviewed to assess their effectiveness.

a. Control Room Activities

Throughout this portion of the inspection, the attitude of operations personnel was positive, cooperative and generally professional, especially when considering the duration of the outage. For the most part, the reactor operators enforced the station policy on limiting access to the control board. The inspectors also observed good involvement by the NSOF (an SRO) in both routine evolutions and outage testing. The shift technical advisor was often involved in performing calculations and tracking/followup of startup open items.

Throughout this outage, the control room noise level was kept to a minimum. This was achieved by moving the equipment clearance desk outside of the control room and establishing and enforcing administrative rules on personnel access. Additionally, the new control room carpeting has had a favorable impact by muffling the background noise level. However, because of the physical layout of the control room, it did maintain a cluttered look.

Station management involvement was evident throughout this period. The inspectors did note that unlike the last several refueling outages, the recovery was handled in a more disciplined fashion that lessened the "push to startup" problems previously observed.

b. Plant Configuration Control

To ascertain whether the licensee was effectively controlling plant configuration, the inspectors conducted extensive walkdowns of various safety systems (main feedwater, main steam, the reactor coolant system, CVCS, safety injection, post-accident hydrogen control and containment depressurization system). The inspectors compared as-found equipment clearances and valve positions with those indicated on various equipment clearance logs and control room status boards and prints. Many instances were noted where the drawings in the control room were not maintained current. Though this problem has been minimized from a technical specification impact by "hardening" required safety systems (such as clearly defining the boric acid addition flow path and placing caution tags on related valves), significant problems could still occur. A specific example observed by the inspectors occurred during performance of OST 1.11.14, Full Flow Safety Injection Tests, when the operators erroneously verified that the low head safety injection pump suction path was open through a review of control room prints when in fact it was not. The operator manually started both low head safety injection pumps with the suction valves closed and ran the pumps for approximately 15 to 20 seconds before another operator observed the incorrect lineup and shut the pumps off before damage could occur. Though these pumps are not required to be operable when the plant is in cold shutdown, the impact to the station would be unfortunate should both have been damaged.

The inspectors noted that the licensee has changed the methodology by which system lineups are performed. A complete system walkdown is now performed one time, with the second verification of critical valves provided either by OSTs or a second walkdown where applicable. The inspectors determined that this system is still weak in that some system walkdowns were initiated in early to mid-July, 1986. The walkdown for some systems was not completed until over 30 days after it was initiated. Consequently, the "NSA Deviation Review Log" which is performed to insure that the final system alignments contained no unacceptable deviations, has little value.

Though the licensee attempted to start the valve lineups after most of the system work was expected to be complete, alignments were often changed several times through equipment clearance work and ongoing outage testing. This contributed greatly to the inability to maintain the control room status board up to date. As an example, the inspectors found a charging pump discharge valve (CH-27) closed in the field, but indicated open on the control room print. After extensive review of ongoing work activities, the licensee was able to determine that this valve was marked Off-Log-Only. Again, this component was not required with the plant in cold shutdown but reliance on control room prints to accurately reflect the position of this manual valve would have posed problems.

Towards the end of the outage and 72 hours prior to leaving Mode 5, the licensee had non-shift SROs independently walk systems down to identify and correct deficiencies. Inspector discussions with these individuals and plant management indicated that they identified the same type of problems as already discussed. The inspectors concluded that the following weaknesses still exist:

(1) Valve lineups in general, were started too early while significant work was still in progress. These lineups, though adequate, were not maintained current as component positions are changed. Also, it could not be determined when a lineup was actually performed.

(2) Drawings in the control room were not always maintained current to reflect actual system alignment.

(3) The system of deviations is an administrative burden on supervisory personnel and is of little value as presently employed.

(4) The clearance system appears to be generally effective but is inefficient; the restoration process is questionable. The off-log-only process needs further examination because of the amount of work that remains on-going throughout an outage.

c. Startup Prerequisities

The inspectors reviewed Operating Manual Chapter 1.50, Station Startup, and the Startup Prerequisite List. Prior to leaving cold shutdown, station management spent a considerable amount of time verifying that all of the prerequisites were complete and all surveillance testing up to date.

Prior to leaving cold shutdown, the inspectors observed completion of portions of the Containment Integrity Checklist and OST 1.12.4, Containment Pressure Check for Air Leakage, on August 11, 1986. This test effectively monitored containment pressure by gathering temperature and pressure data for a four hour period to verify that there was less than a 0.1 psi differential corrected containment pressure over the time period. This practice goes beyond completing valve lineups in assuring that no air in-leakage exists.

d. Summary

Many of the problems evident during the recovery from the last two refueling outages were successfully avoided during this recovery. Plant configuration problems that did occur had little impact on plant safety because control over the required systems and components was administratively hardened. Startup prerequisite reviews were extensive and thorough, though they were manpower intensive. This indicates that DLC management placed a high priority on the conduct of a smooth and error free startup. Commitments made to the NRC in DLC letter of April 11, 1985, were met. Discussions with senior management indicated that they were cognizant of the equipment and plant configuration control problems previously discussed, and that further improvements were actively being explored. The inspector noted that further solutions would also have to account for the integration of Unit 2 activities. This concern was acknowledged.

8. Design Change Package Open Item Control

The inspector reviewed the licensee's administrative procedures and several design change packages (DCPs) to verify that DLC has positive control over open items which remain after operational acceptance. A DCP open item is any item remaining unresolved after the DCP is turned over to the station and operationally accepted. These items include, but are not limited to, construction open items, incomplete station turnover activities and any deficiencies identified during the preoperational testing.

The primary responsibility for tracking DCP open items changed in 1984 when the reorganization of the Engineering Departments took place. Before that time, Station Engineering tracked all of the open items; but after the reorganization, Station Engineering no longer existed. Nuclear Engineering and Construction Unit (NECU) was created and assumed the tracking of only those open items which related directly to engineering or construction. The remaining station open items (those related to the Technical Services Group, Nuclear Training Group, Testing and Plant Performance, Station Maintenance Instrument and Control, and Station Operations) have been informally tracked by Planning and Outage Management (P&OM).

Currently, the general control over DCP open items is governed by Nuclear Engineering Management Procedure (NEMP) 2.8, Rev. 3, Handling of Design Change Packages, and Planning and Outage Management Manual (P&OMM) Chapter 23, Design Change Package Matrix and Open Items Programs. NEMP 2.8 describes the engineering and interface controls in implementing a DCP. P&OMM 23 establishes the methods and requirements of the DCP Matrix and Open Items Program. It monitors milestones of engineering and installation with the DCPs which have been turned over as operationally acceptable.

The licensee is aware of the weakness in the program for DCP open items and is planning on developing and implementing new procedures for DCP handling and a tracking system for all DCP open items. Completion is scheduled before the end of 1986. Implementation of this DCP program and update of the DCP open items tracking list will be Unresolved Item (86-18-04).

9. Miscellaneous Safety Issues

a. IE Bulletin 85-03, MOV Common Mode Failure During Plant Transient due to Improper Switch Settings

The inspector informed the licensee that DLC letter of May 16, 1986, which contained their initial response to the subject bulletin was found to be inadequate by the Office of Inspection and Enforcement. Specifically, because no additional differential pressure tests were planned, amplification of the switch setpoint establishment methodology would be needed. This topic had been briefly discussed in Detail 11 of NRC Inspection Report 334/86-11. The inspector's comments were acknowledged by the Senior Licensing Engineer.

b. IE Bulletin 86-02, Static "O" Ring Differential Pressure Switches

This bulletin was issued to alert licensees of potential problems with Series 102 and 103 differential pressure switches supplied by SOR, Inc. for use as electrical equipment important to safety. The inspector reviewed licensing memorandum MD1NSM:2257 dated July 23, 1986, which indicated that a review of the Maintenance Equipment List and applicable technical manuals identified none of the subject model switches used at BV-1. No further action is required and this item is closed.

c. IE Information Notice 86-68, Potential Deficiency in Improperly Rated Field Wiring to Solenoid Valve

This Notice detailed a design deficiency in field run cables to Valcor solenoid valves at several facilities. The field run cables that were terminated inside the valve body, housing a large energized solenoid, were subjected to a temperature range of 250 - 280 F for an extended period of time. However, the wiring was found to have an insulation temperature rating of 90 C (144 F). To correct this deficiency, Beaver Valley instituted DCP 690 and replaced the then existing 90 C wire with a length of 200 C wire for about 33 SOVs in the plant. Six of the SOVs on the reactor vessel vent system were to be upgraded for environmental consideration. While performing this work, the licensee determined that past problems with the SOV on the reactor hot leg sample isolation valve (TV-SS-105A1) appeared to be due to internal valve spring failure.

The failure mechanism of the valve springs was determined to be hydrogen embrittlement of the 17-7 ph stainless steel spring material. Valcor Engineering Corporation informed the licensee of three instances at other PWR facilities where this particular material spring failure occurred after approximately one to two years of service when exposed to reactor chemistry water at temperatures above 440 F. It was recommended that replacement springs of a cobalt based alloy (Elgiloy) be used as a replacement material as it is not subject to hydrogen embrittlement.

Discussions with responsible engineers indicated that only three valves (TV-SS-105A1, A2, and TV-SS-106D) were subjected to this phenomena and required spring replacement during the Fifth Refueling Outage. This work was done under the plant maintenance work request system and TER 124 was initiated to update drawing and technical manuals to show the new material as used. None of the other valves indicated the type of degradation as evidenced by the successful Type C Leak Rate Test conducted. The inspector had no further questions at this time.

10. Hydrogen Recombiners

DCP 621 was initiated to upgrade the Environmental Qualification of the Hydrogen Recombiners to IEEE Standard 323, 1974 edition. The work on the Rockwell Hydrogen Recombiners included replacement of the control cabinets and a skid mounted blower unit, which included replacement of the positive blower with a centrifugal unit.

Initial post modification testing was conducted under OST 1.46.4, Six Month Hydrogen Recombiner Test, which recirculated blower flow rather than aligning the system to the normal pipe arrangement which pulls a suction and discharges into the containment atmosphere, due to outage conditions. After pulling the initial vacuum on containment (down to about 9.4 psia) the 18 month surveillance test was conducted per OST 1.46.2, Post-DBA Hydrogen Control System Tests, which uses the normal flow path from and to containment. Technical Specification 4.6.4.2.b.3 requires each hydrogen recombiner system to be demonstrated operable at least once per 18 months by verifying that the system is capable of producing a flow rate of greater than or equal to 50 standard cubic feet per minute (scfm) when using containment atmosphere air at a pressure of less than or equal to 13 psia. After extrapolating the data from the 9.5 psia atmosphere test pressure to something less than 13 psia, the licensee determined that both trains would fail to meet this criteria.

Additional testing indicated that the centrifugal blowers were not able to overcome the line resistances due to the weight loaded 2" swing check valves installed inside containment on both the suction and discharge lines. To overcome the flow resistance offered by these valves, the licensee decided that a pipe and valve configuration change would be necessary. Since the inside containment check valve on the suction line does not function as an isolation valve, the internals were removed and a new check valve installed outside of containment downstream of the containment vacuum pump isolation valves to prevent air inleakage should a vacuum pump fail. However, the discharge check valve does serve as a containment isolation valve and consequently, required the installation of a second ball valve outside of containment to provide double isolation. This will require a technical specification change to Table 3.6-1, Containment Isolation Valves, which contains a description of each containment penetration. After a series of conference calls between the licensee, NRR and Region 1, the description of the physical change as contained in the DLC Safety Evaluation of August 22, 1986, was found acceptable. The licensee was granted verbal permission to restart the station while proposed operating license change request No. 130 was processed by NRR on an expedited basis.

The inspector reviewed both the Type C leak test data and subsequent system testing performed at 12.85 psia which indicated that there was about a 10% margin above the minimum flow level specified in the technical specification. The inspector walked down the modification and verified that the two additional containment isolation ball valves were maintained locked closed and under administrative control. A review of control room prints indicated that they had been updated in a timely manner to reflect this modification. The inspector determined that the licensee completed the modification and conducted the testing specified in the DLC letter of August 22, 1986, and formal approval of the technical specification change is under the jurisdiction of NRR.

11. Diesel Generator No. 1 Monthly Test

During the performance of OST 1.36.1, the governor for the No. 1 Diesel Generator was not properly responding to load changes. Specifically, when the diesel generator governor control switch was placed in the raise position to increase load, load would continue to increase until the diesel generator governor control switch was placed in the decrease position. Upon reversing the loading it would continue down in a like manner. Close, dedicated operator action was needed to prevent overload conditions during the governor's unstable operation. The OST was considered unsatisfactory due to the uncertain manner in which the No. 1 Diesel Generator might perform when called upon to receive and power emergency loads.

The vendor was contacted and suggested that the OST be rerun at different governor speed droop setting. The unsatisfactory operation had been conducted with a setting of 42. The OST was rerun with the droop settings below 42 and slightly varying the load from a full load of 2850 kW. This was done to obtain proper governor response. A final setting of 38 was established and OST 1.36.1 was then signed off as being acceptable.

12. 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.