U.S. NUCLEAR REGULATORY COMMISSION

REGION I

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Report No.	50-334/96-03, 50-412/96-03
Licensee:	Duquesne Light Company (DLC)
Facility:	Beaver Valley Power Station, Units 1 and 2
Location:	Shippingport, Pennsylvania
Dates:	February 13 - March 25, 1996
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EXECUTIVE SUMMARY

Beaver Valley Power Station, Units 1 & 2
NRC Inspection Report 50-334/96-03, 50-412/96-03

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes the results of announced inspections by a regional operations engineer.

Operations

Control room operations were appropriately performed. Operators consistently provided timely information to the assistant nuclear shift supervisor (ANSS) regarding plant alarms and the reasons for the alarms. In spite of the ANSS workload, all of the individuals observed in the ANSS position carried out their duties well and maintained an overall awareness of plant status.

The stations current active senior reactor operator staffing was practically at the minimum level to support technical specification requirements of two per shift but control room staffing levels met minimum technical specification requirements. The ANSS position was the busiest, most burdened position in the control room. The current operations organization had very limited operations support personnel to assist in the reduction of the SRO burden. The licensee planned to continue to assess the SRO work activities to modify or eliminate unnecessary tasks. The licensee had plans in place for licensing additional senior reactor operators.

The near term STA staffing situation with only four qualified individuals to support a five shift rotation was considered to be a critical situation to support continued plant operation. The STA reduced staffing was expected to be temporary (5 months), until former STAs were recertified. The licensee had preliminary plans for training and qualification of additional STA staff. The development of a long term operating organization was ongoing and was considered to be essential to assure adequate staffing to support continued plant operations in accordance with technical specifications.

Initial shutdown operations for the Unit 1 refueling outage were well controlled and received good oversight from the shift supervisors. However a feedwater isolation and turbine trip occurred due to high steam generator level. The inspectors did not observe any deficiencies with operator performance prior to or during the transient. However, the sequencing of testing as directed by Operations management did significantly contribute to the difficulties experienced by the operators in maintaining proper RCS temperature control. A root cause analysis, including corrective actions is under review by the licensee.

Control rod drop testing was properly conducted with good management oversight. Test results demonstrated the operability of the control rods and were consistent with beginning of core data.

(EXECUTIVE SUMMARY CONTINUED)

Very good management involvement and oversight was provided for Unit 1 reactor coolant system loop isolation. Operators successfully isolated all three RCS loops with proper attention towards the safety implications involved with reduced RCS inventory and assured continued decay heat removal.

Maintenance

Maintenance engineering provided timely support for an investigation of a reactor coolant pump vibration alarm which was due to a loose probe and not high vibrations.

The on-line maintenance of a station system transformer used risk assessment to assure a conservative plant alignment was maintained and to limit permissible outage time. Good preplanning and coordination between station groups minimized out of service time.

Good evaluations and corrective actions were observed when static test torque values were measured in excess of preset values, including the component engineer's weak link analysis and adding additional inspections to valve test programs.

Engineering

Appropriate root cause analyses and corrective actions were taken for two event reports which were reviewed and closed.

The licensee had properly addressed lower temperature limits for the service water system.

A design change package was properly evaluated with thorough instructions to control the installation and post-installation test activities.

The root cause analysis of a previous transformer failure was thorough. Corrective actions were being properly pursued.

Plant Support

Licensee personnel were properly implementing the radiological protection and security programs for the activities observed.

Safety Assessment and Quality Verification

Pre-outage planning was performed to implement the licensees shutdown safety philosophy which remained the licensee's highest priority. The outage schedule planning ensured a greater than minimum required level of defense-in-depth was established for key safety functions, where possible. The licensee developed contingency actions and implemented a number of precautions to minimize the likelihood of a challenge to the key safety functions. The preoutage shutdown safety review was considered by the inspectors to be of very high quality.

TABLE OF CONTENTS

Report Details

Summary of Plant Status

Unit 1 operated at 100% power from the beginning of this inspection period until February 23, 1996, when power was reduced to 95% for condenser and cooling tower pump maintenance. Power drooped from 95% to 87% between March 8 and 15 due to end of cycle fuel burnup. On March 15, power was reduced to 65% in order to remove a main feedwater pump from service for maintenance. On March 22, a power reduction was commenced for the refueling outage. The output breakers were opened at 10:56 pm on March 22. The unit entered cold shutdown (Mode 5) at 11:03 pm on March 23.

Unit 2 operated at full power from the beginning of this inspection period until March 13, 1996, when power was reduced to 45% so that a heater drain pump and a separator drain pump could be removed from service for maintenance. Power was returned to 100% on March 15 and the unit operated at full power throughout the remainder of this inspection period.

I. Operations

1.1 Operational Safety Verification (71707)

Using applicable drawings and check-off lists, the inspectors independently verified safety system operability by performing control panel and field walkdowns of the following systems: control room emergency bottled air pressurization system, reactor plant river water system components in the intake structure, hydrogen recombiners, emergency diesel generator air start, cooling water, and fuel oil systems. These systems were properly aligned. During the inspectors walkdown of the diesel cooling water system, the inspectors identified a discrepancy with respect to the Updated Final Safety Analysis Report (UFSAR). Specifically, the Unit 2 UFSAR Section 9.2.1.1.2 describes adding chemicals to the emergency diesel generator coolers for wet layup from a chemical addition tank to prevent undue corrosion. However, since initial unit startup, it has not been the licensee's practice to place the diesel heat exchangers in chemical wet layup other than with the chemical injection points provided for controlling algae, macro invertebrate growth, and silt deposition, and corrosion inhibitors were only recently added. This observation is under review by the licensee. The inspectors observed plant operation and verified that the plant was operated safely and in accordance with licensee procedures and regulatory requirements. Regular tours were conducted of the following plant areas:

- Control Room
- Auxiliary Buildings
- Switchgear Areas
- Access Control Points
- Protected Areas
- Spent Fuel Buildings
- Diesel Generator Buildings
- Safeguards Areas
- Service Buildings
- Turbine Buildings
- Intake Structure
- Yard Areas
- Containment Penetration Areas
- Unit 1 Containment Building

During the course of the inspection, discussions were conducted with operators concerning knowledge of recent changes to procedures, facility configuration, and plant conditions. The inspectors verified adherence to approved procedures for ongoing activities observed. Shift turnovers were witnessed and staffing requirements confirmed. The inspectors found that control room access was properly controlled and a professional atmosphere was maintained. Inspectors' comments or questions resulting from these reviews were resolved by licensee personnel.

Control room instruments and plant computer indications were observed for correlation between channels and for conformance with technical specification (TS) requirements. Operability of engineered safety features, other safety related systems, and onsite and offsite power sources were verified. The inspectors observed various alarm conditions and confirmed that operator response was in accordance with plant operating procedures. Compliance with TSs and implementation of appropriate action statements for equipment out of service were inspected. Logs and records were reviewed to determine if entries were accurate and properly identified equipment status or deficiencies. These records included operating logs, turnover sheets, system safety tags, and the jumper and lifted lead book. The inspectors also examined the condition of various fire protection, meteorological, and seismic monitoring systems.

1.2 Conduct of Operations (71715)

Scope

The inspectors observed both Unit 1 and Unit 2 control room operations on January 30, 31, February 1, March 5 and 6, 1996. The inspectors assessed the ability of the senior reactor operators (SRO) to carry out the responsibilities of the SROs per technical specifications and Section 48 (Conduct of Operations) of the Beaver Valley Operations Manual. In addition, the inspectors observed the interactions of the operations crew and also conducted interviews with the operators.

Findings

The control room crew consisted of a nuclear shift supervisor (NSS), assistant nuclear shift supervisor (ANSS) and two reactor operators (RO) and a non licensed STA. The NSS and ANSS were licensed senior reactor operators, and the two reactor operators were licensed reactor operators. In addition, depending on the planned work activity, an extra licensed reactor operator was used to conduct surveillance testing. Staffing levels were consistent with the technical specification requirements.

On several occasions, licensed operator staffing levels in the control room were observed to be one SRO and one RO as permitted by technical specifications. At no time did the inspectors observe control room staffing levels that violated technical specifications. There were various reasons for the reduced staffing level, which included required coordination meetings, plant tours, problem resolution and personal needs. The inspectors concluded that some instances of minimal staffing levels were unnecessary and could have been avoided by more effective control room personnel awareness and coordination.

The NSS and ANSS were aware of the plans for the shift and effectively communicated and assigned work assignments to the shift. The ROs consistently provided timely information to the ANSS regarding plant alarms and the reasons for the alarms.

The ANSSs for both Units were by far the busiest, in each unit control room. The Unit 2 ANSSs were considerably busier than the Unit 1 ANSSs. This observation was based on actual observation as input from the various interviews conducted. The ANSSs workload included assigning work to operators, authorizing maintenance work, reviewing completed work, reviewing future clearances, responding to problem reports, responding to unexpected operational problems, conducting plant tours and logging.

Daily work plans significantly influenced the ANSS workload. The ANSSs were significantly less burdened when the daily work plan was less involved.

In spite of the ANSS workload, all of the individuals observed in the ANSS position carried out their duties well and maintained an overall awareness of plant status. There were some tasks that the ANSSs performed, such as procedure copying and computer input of problem reports, that appeared to be assignable to other individuals.

Duquesne Light Company had performed some short term actions to minimize the workload of the SROs and planned to computerize shift logging and non-licensed logging review as additional workload reduction improvements. Duquesne Light Company indicated that they planned to further independently assess SRO workload in attempts to reduce the SRO workload until additional SRO staffing could be licensed.

Conclusion

Control room operations were appropriately performed. Control room staffing levels met minimum technical specification requirements. The ANSS position was the busiest, most burdened position in the control room. Duquesne Light Company planned to continue to assess the SRO work activities to modify or eliminate unnecessary tasks.

1.3 Operator Training and Qualification (71715)

Scope

The inspectors interviewed the Operations Training Director to understand the Duquesne Light Company (DLC) plans for the licensing of new operators and for the training and qualification of shift technical advisors (STA).

Findings

DLC had initiated a SRO class for both Unit 1 and Unit 2. For Unit 1, the class consisted of 3 instant applicants and 1 upgrade applicant with an examination scheduled for March 17. 1997. For Unit 2, the class consisted of 2 instant applicants and 3 upgrade applicants with an examination scheduled for February 10, 1997. The training department budget plans included starting another senior operator licensing class immediately after the 1997 examinations. DLC had no plans for additional reactor operator license classes.

For the STAs, DLC had plans to recertify two former STAs for control room duties, complete the training of an additional person, and initiate a class for new STAs. The exact schedule and class size were still being developed by DLC. In addition, the licensee has hired a contractor to perform problem report root cause analyses normally assigned to STAs.

Conclusion

DLC had plans in place for licensing additional senior reactor operators and augmenting the STA staff. DLC had preliminary plans for training and qualification of additional shift technical advisors.

1.4 Operations Organization and Administration (71715)

Scope

The inspectors assessed the operations organization to understand the DLC long and short term plans for addressing staffing level concerns regarding licensed operators. In addition, the inspectors reviewed the staffing for shift technical advisors (STA). Interviews with operations staff personnel as well as supervisors and managers were conducted.

Findings

The DLC staffing levels of the SRO and RO positions during this inspection were as follows:

	Total SROs	Active SROs	Total ROs	Active ROs
UNIT-1	22	11	27	18
UNIT-2	15	12	20	16

An active operator was an operator that stood watch for at least seven-eight hour shifts per quarter.

In addition, there were five individuals qualified to stand the STA position.

Both Unit 1 and Unit 2 operated on a five-shift rotation. DLC had sufficient active SROs and ROs to support a five shift rotation. However, since there were limited active SROs on both units, overtime was used to provide shift coverage when individuals were either on sick leave, personnel leave, vacation leave or assigned to other tasks. A review of the long-term overtime usage indicated that, on average, overtime worked was comparable in length to leave time. The SROs indicated that as a group, they tried to support planned leave periods of individual operators by working overtime. There was no indication that overtime limits of technical specifications were exceeded.

During this inspection period, the inspectors observed that both the NSS and ANSS position were periodically staffed with individuals working a 12-hour day to cover for personnel leave or rescheduled requalification training.

Feedback from the SROs indicated that working a five-shift rotation with overtime to compensate for the few individuals actively performing SRO licensed duties was physically challenging. The SROs indicated that assigned tasks in the control room were not impacted by their work schedule and staffing, but rather the other assigned tasks outside of the control room, such as biennial procedure reviews, were difficult to complete. Under a five-shift rotation, the SROs are either on shift or in training. Due to the rebalancing of work onto all shifts, the SRO workload on the shifts did not allow sufficient time to complete these other assigned tasks.

The current operations organization had very limited operations support personnel to assist in the reduction of the SRO burden. Only one individual for each unit was currently providing operations support. The operations organization desired to implement a work control center for each unit to reduce the burden. On Unit 1 there was a functioning work control center, but not yet on Unit 2. However, there were no administrative descriptions nor approved organizational staffing levels for either of the work control centers.

The inspectors requested the operations management plans for future SRO development. The Operations organization indicated that the desired SRO staffing was 22 SROs for each unit with 17 actively performing licensed duties and 5 SROs in other departments. The 17 active SROs would include SROs on shift rotation, extra SRO help on daylight, work control center SROs and staff SRO operations support. The operators organization expected to achieve this goal by 1999 with assumptions on class size and attrition. The DLC SRO staffing level goal of 22 per unit will result in staffing that is more than 20% lower than the average SRO staffing of plants in Region I on a single unit basis.

One of the qualified STAs was recently selected to be a part of the 1997 SRO license class. This left only four qualified STAs to comply with technical specifications STA on-shift coverage. DLC indicated that the one STA would not be removed from shift until after completion of the Unit 1 outage which was expected in early May. The DLC training organization plan to recertify former STAs was estimated by the training department to take approximately 21 weeks. The inspectors noted that STA on-shift coverage for approximately 5 months, would rely on a four-shift rotation of STAs, which would require the use of overtime. The inspectors considered that with proper planning, the on-shift coverage and requalification training could be conducted without exceeding the overtime requirements of technical specifications. The inspectors noted, however, that the time period with a four STA shift rotation should be minimized.

Operations management had not yet developed a staffing plan to address the long term operating organization. Whereas plans were provided to the inspectors regarding SRO staffing plans, DLC was developing the long-term plans for the operating organization which included the staffing levels of the non-licensed auxiliary operators, reactor operators, senior reactor operators, work control centers, and operations support personnel. The DLC plans were not available for review during this inspection.

Conclusion

The DLC current active senior reactor operator staffing was practically at the minimum level to support technical specification requirements of two per shift. The STA near term situation with only four qualified individuals to support a five-shift rotation was considered to be a critical situation to support continued plant operation. The STA reduced staffing was expected to be temporary (5 months) until former STAs were recertified. The development of a long-term operating organization was ongoing and was considered, by the inspectors, to be essential to assure adequate staffing to support continued plant operations in accordance with technical specifications.

1.5 Engineered Safeguards Feature Actuation: Feedwater Isolation During Unit 1 Shutdown (71707)

The inspectors observed the Unit 1 plant shutdown in preparation for the eleventh refueling outage. The observations included the unit load reduction, removal of the main generator from service, and subcritical operations.

Initial load following operations were well controlled without complication as the shift supervisors provided good oversight. Subsequently, however, a main feedwater isolation and turbine trip occurred due to a hi-hi 'A' steam generator level (72% narrow range). The main unit generator had just been removed from service, and reactor power was approximately 5%. After the generator was taken off line (an 80MW load reduction), reactor coolant system average temperature (RCS Tave) increased as expected. Steam dumps responded properly and Tave began to decrease. Simultaneously, the reactor operator began boration in order to establish an all rods out (226 steps) condition in preparation for control rod drop testing. This was the first occasion in which control rod drop testing was performed at end of core life and was required by NRC Bulletin 96-01 (see Section 1.6). Additionally, the main turbine was maintained on line in preparation for pedestal checks. This testing sequence was directed by the night orders issued by Operations Management. However, the combination of boration and xenon buildup contributed excessive negative reactivity and resulted in RCS temperature rapidly decreasing to from 555°F to 537°F. This in turn resulted in a decrease of secondary side steam generator pressure while the turbine continued to place a steam demand on the steam generators. The steam generator level rapidly swelled to the high level setpoint. The plant operator controlling feedwater flow to the generators had isolated the bypass regulating valves, however, the steam generator swell could not be controlled. Nuclear instrumentation indication that power was higher than actual may also have contributed to this event. After the turbine trip, operators appropriately stabilized the plant in accordance with operating procedures.

The inspectors did not observe any deficiencies with operator performance prior to or during the transient. However, the sequencing of testing as directed by Operations management did significantly contribute to the difficulties experienced by the operators in maintaining proper RCS temperature control. The inspectors discussed the use of night orders with operations management and agreed with the explanation that they are intended to give general direction and an overview of plans and are not used as procedures. Operations management also reviewed this philosophy with the shift operators. A root cause analysis, including corrective actions is under review by the licensee.

1.6 Unit 1 Control Rod Drop Testing (71707, 61726)

NRC Bulletin 96-01, "Control Rod Insertion Problems," alerted licensees of recent industry experience with sticking of control rods associated with Westinghouse fuel. Of particular concern was Vantage 5H fuel with burn up exceeding 45,000 MWD/MTU. The inspectors observed the rod drop testing required by the bulletin in order to verify that the control rods could have performed their intended function. Unit 1 does use Vantage 5H fuel, however; the highest burn up for a rodded assembly was 43,953 MWD/MTU.

The rod drop tests were designated as an "Infrequently Performed Test or Evolution," thus requiring additional management attention and oversight. This test was being performed for the first time for end-of-core life conditions. This testing is normally performed for beginning of life core conditions after core reload. Operations management properly stressed the need for added diligence and safety awareness because of the unique conditions of the test. A dedicated reactor operator was assigned to the test so as to maintain proper focus on reactor power and changing reactivity conditions. Sufficient shutdown margin was established via boration to allow an all rods out condition prior to dropping the rods. Testing sequence during the shutdown did contribute to operator difficulty in reactor coolant temperature control and is discussed in Section 1.5. The actual rod drop testing was completed safely with proper attention to detail. All control rods exhibited proper recoil/bounce and rod drop times were well within the technical specification minimum of 2.7 seconds. Rod drop times were consistent with beginning of core data and averaged between 1.2 to 1.4 seconds. The licensee plans to forward the details of the tests to the NRC as required by the bulletin.

The inspectors also identified two discrepancies with respect to the Unit 1 Updated Final Safety Analysis Report (UFSAR). Specifically, UFSAR Section 3.2.2.4.2 states that the acceptance criteria for rod drop testing, from start of rod cluster control assembly motion to dashpot entry, is 2.2 seconds. However, Technical Specification 3.1.3.4 specifies an acceptance criteria of less than 2.7 seconds. Further review by the inspectors revealed that licensee Amendment 144, approved September 28, 1989, changed the acceptance criteria from 2.2 second to 2.7 seconds to account for the use of Vantage 5H fuel; however the UFSAR was not updated accordingly. In addition, UFSAR Section 3.2.3.4.1 states that:

> The full length rod cluster control assemblies are functionally tested, following core loading but prior to criticality to demonstrate reliable operation of the assemblies. Each assembly

is operated (and tripped) one time at no flow/cold conditions and one time at full flow/hot conditions.

The licensee had in the past also performed rod drop testing under cold conditions, but have since discontinued this practice since it does not provide any additional information beyond what the full flow/hot rod drop testing provides. This position is consistent with technical specifications which require testing only under full flow/hot conditions. The observations by the inspectors are currently under review by the licensee for corrective action.

Overall, the inspectors concluded that the rod drop testing was properly conducted with good management oversight. Test results properly demonstrated the operability of the control rods.

1.7 Unit 1 Reactor Coolant Loop Isolation (71707)

The inspectors observed the isolation of the reactor coolant loops three days after the plant shutdown. This activity was managed as a high risk evolution since three loops were isolated on the same day this early in the outage. In past practices, the third loop had not been isolated until the reactor refueling cavity was flooded when decay heat loads were less. Also, having the cavity filled with water allowed greater RCS inventory to be available in the event of a loss of decay heat removal (DHR) event would occur.

The inspectors observed the pre-evolution briefing conducted by Operations Management. The increased risk to shutdown cooling was well emphasized to the operating crew. Precautions in maintaining residual heat removal (RHR) system fully operable were discussed. For example, potential challenges to power supplies were eliminated by securing all switchyard activities between the period of loop isolation and cavity flood. Also, interlocks associated with automatic RHR system isolation were defeated. Diesel generators were also not released for maintenance until cavity flood. Contingency plans, abnormal operating procedure usage, and time estimations to boiling were fully discussed. Lessons learned from past industry loss of DHR events were reviewed. The inspectors also verified that acceptance criteria were satisfied for the RHR pump performance tests. The actual isolation of all three loops was completed safely and without complication as directed by the well detailed procedure. Operators carefully monitored pressurizer and volume control tank levels following each loop isolation to ensure that unexpected RCS inventory loses did not occur.

Overall, the inspectors concluded that very good management involvement and oversight was provided in this high risk evolution. Operators successfully isolated all three RCS loops with proper attention towards the safety implications involved with reduced RCS inventory and assured reliable decay heat removal.

II. Maintenance

2.1 Maintenance Observations (62703)

The inspectors reviewed selected maintenance activities to assure that: the activity did not violate Technical Specification Limiting Conditions for Operation and that redundant components were operable; required approvals and releases had been obtained prior to commencing work; procedures used for the task were adequate and work was within the skills of the trade; activities were accomplished by qualified personnel; radiological and fire prevention controls were adequate and implemented; QC hold points were established where required and observed; and equipment was properly tested and returned to service.

The maintenance work requests (MWRs) listed below were observed and reviewed. Unless otherwise indicated, the activities observed and reviewed were properly conducted.

- MWR-049626 MOV-RW-104A, Static BARTS Test/PMP
- MWR-050310 VS-D-40-1A, Replace Bladder
- MWR-050271 Environmental Qualification Inspection of 2MSS-SOV-105F
- MWR-050913 Investigation of Solid State Protection System Test Discrepancy
- MWR-050474 Investigation of Reactor Coolant Pump (RCP-21A) Vibrations

The inspectors observed the investigation associated with high vibration alarms associated with the 'A' reactor coolant pump shaft. The licensee contacted Westinghouse specialists who provided support for the investigation. Vibration spectrum analysis determined that the source of the alarms was a loose probe and not an actual high vibration condition. A maintenance work order has been initiated to correct the deficiency during the next outage. The inspectors concluded that maintenance engineering personnel provided timely support for the investigation process to determine if a valid alarm condition existed.

2.1.1 On-Line Maintenance Practices (62703)

The inspectors reviewed the licensee's on-line maintenance of the Unit 1 'A' station system transformer. The relay checks associated with this transformer required that one of the two offsite station power supplies be removed from service. Technical specifications provides an allowable outage time of 72 hours.

Temporary operating procedure 1TOP-95-16 provides the guidelines for on-line maintenance. Maximum permissible out-of-service times are based on the limiting condition of either probabilistic risk assessment (PRA) modeling or 33% of the technical specification allowable outage time. For this maintenance activity, 33% of technical specification allowed outage time was more limiting, since PRA modeling determined a maximum permissible outage time of 31 hours. The risk assessment also evaluates the impact of other maintenance activities to ensure that there is no compounding increase in risk to the plant. Recent industry experience at Catawba demonstrated how on-line maintenance of multiple components of the same train resulted in a nonconservative plant alignment. The on-line maintenance of the station transformer needed to be accomplished prior to the refueling outage. During the outage, the normal backfeed method of supplying power to the station, via the main unit transformer would not be available. The main unit transformer will be replaced. Thus, on-line maintenance provided a benefit of maintaining a redundant operable offsite power supply during the refueling outage. Actual work scope was properly reviewed and assessed, such that the maintenance time was consistent with the projected maintenance time. Proper job preplanning and coordination between the operators, electricians, and substation personnel minimized the out-of-service time. The station transformer was out of service for a total of 24 hours. Prior to removing the transformer from service, operations properly verified the operability of both emergency diesel generators. Additionally, all switchyard activities were secured so as not to jeopardize the existing single offsite power supply.

Overall, the inspectors assessed the on-line maintenance of the transformer to result in a net safety benefit relative to the upcoming outage work. Additionally, the on-line maintenance guidelines ensured a conservative plant alignment was maintained using risk assessment modeling.

2.2 Surveillance Observations (61726)

The inspectors witnessed/reviewed selected surveillance tests to determine whether properly approved procedures were in use, details were adequate, test instrumentation was properly calibrated and used, technical specifications were satisfied, testing was performed by qualified personnel, and test results satisfied acceptance criteria or were properly dispositioned. The following operational surveillance tests (OSTs) and Beaver Valley Tests (BVTs) were observed and reviewed. Unless otherwise indicated, the activities observed and reviewed were properly conducted without any notable deficiencies.

- 1OST-26.4 Pedestal Checks (see Section 1.5)
- 1BVT 1.1.10 Control Rod Drop Time Measurement for NRC Bulletin 96-01 (see Sections 1.5 and 1.6)
- 2OST-30.17A Service Water Pump Train 'A' Seal Water System Operability Test

2.3 Unit 1 Recirculation Spray Heat Exchanger Isolation Valve Testing (61726, 62703, 37551)

The station responded well when the static test torque values were measured in excess of the preset values on the Unit 1 recirculation spray heat exchanger inlet and outlet isolation valves (MOV-RW-104A and MOV-RW-105A). Component engineering personnel reviewed the weak link analysis for these valves and elected to visually inspect the gear drive (HBC) units to determine if operation in the high torque condition had caused damage. The HBC unit visual inspection revealed noticeable wear on the MOV-RW-104A HBC unit worm shaft and drive sleeve.

The licensee replaced the MOV-RW-104A HBC unit worm shaft, drive sleeve and bearings, performed static valve testing, and returned MOV-RW-104A to service.

Engineering performed a root cause investigation for the degraded HBC condition and attributed the wear to degradation over time rather than operation in the high torque region. The inspectors observed engineering personnel perform a bench top test involving operation of a similar valve and HBC unit in a high torque condition and did not observe any damage to any HBC unit components.

Long-term corrective actions for the wear problem included incorporation of a visual HBC unit inspection into the periodic valve test program. The inspectors concluded that the root cause and corrective actions were appropriate.

III. Engineering

3.1 Review of Written Reports (92700, 90712)

The inspectors reviewed Licensee Event Reports (LERs) and other reports submitted to the NRC to verify that the details of the events were clearly reported, including accuracy of the description of cause and adequacy of corrective action. The inspectors determined whether further information was required from the licensee, whether generic implications were indicated, and whether the event warranted further onsite follow-up. The following LERs were reviewed:

Unit 1:

95-09 ASME Valves Not Tested Within Technical Specification Surveillance Interval

This LER was characterized as a missed surveillance because several of the 160 valves in the test procedure were not stroke tested within the required quarterly interval. The time between the completion date for the prior test (July 16, 1995) and the latest test (November 7, 1995) was within the allowable interval of 115 days (including the 25% grace period). However, specific time intervals between test dates for 83 of the 160 individual valves were between 117 and 129 days. The cause of this problem was the failure to account for the collective impact of test start dates and test duration when scheduling and performing the surveillance. The 83 valves were found to have been stroke tested satisfactorily. The licensee reviewed the results of this surveillance for the last 2 years for both Unit 1 and 2, and did not identify similar deficiencies. The licensee has subsequently implemented a program to schedule surveillances on a 12-week schedule in order to maintain a heightened level of awareness and prevent recurrence.

The inspectors reviewed the details related to this event as documented in the LER and found that the licensee's root cause determination and specific corrective actions were acceptable. However, the licensee's overall investigation appeared to address only the valve stroke surveillance test. Subsequent discussions with station personnel indicated that other operations surveillance tests were reviewed for similar impact although not specified in the LER. The quarterly valve stroke test is a unique surveillance because of the nature and amount of testing performed, resulting in a long test duration.

The licensee further stated that maintenance surveillance tests are performed on a channel-specific basis, and that the duration of those tests do not impact the test intervals. Therefore, this missed surveillance appeared to be an isolated occurrence. The licensee's actions were acceptable. This LER is closed.

95-11 Condition Prohibited by Technical Specifications - Missed Source Range Surveillance

This LER described a missed "compensatory" surveillance in which a 12-hour shutdown margin determination, required because the source range nuclear instruments were inoperable, was omitted during a plant shutdown that began on December 18, 1995. During the shutdown, a control room senior reactor operator inadvertently missed a procedural requirement that directs operators to perform a surveillance test (if not done within the previous 30 days) to confirm operability of the source range nuclear instruments. Technical Specification 3.3.1.1 action statement requires a compensatory 12-hour shutdown margin determination when the source range instruments are inoperable. Because the operators failed to perform the surveillance test, the two source range instruments were inoperable. Periodic shutdown margin determinations were performed during the shutdown as a result of other proceduralized requirements, however, they were not done every 12 hours as required. The licensee reviewed the times during which shutdown margin determinations were required, and identified that one 12-hour shutdown margin determination was missed from the time of the shutdown until the missed surveillance was subsequently performed satisfactorily on December 21, 1995.

The safety impact of this event was low. Although the surveillance was missed on one occasion, the two source range channels had been in service and capable of performing the intended safety functions. In addition, the licensee confirmed that the reactor coolant system boron concentration and shutdown margin remained above the Technical Specification minimum values at all times during the shutdown. The licensee reviewed shutdown procedures for both units to incorporate enhancements to prevent recurrence of this type of event. The inspectors reviewed the licensee's response to this event and determined that their actions were appropriate. This LER is closed.

3.2 River Water Lower Temperature Limit (71707)

Background:

The inspectors performed a review of the Unit 1 and Unit 2 service water temperature limits based on an event at Haddem Neck where the river temperature dropped below the design basis of 35°F. Unit 1 & 2 Technical Specifications and Updated Final Safety Analysis Reports do not specify a lower temperature limit, but the licensee has addressed the lower river temperature issue and has determined 32°F to be the lower limit.

Recirculation Spray Heat Exchangers

The 32°F temperature does not cause overcooling of the containment and thereby the Haddem Neck scenario is not applicable at Beaver Valley. At Beaver

Valley, the containment atmosphere coolers are tripped during containment isolation.

Charging Pump Oil Coolers

The oil coolers associated with the charging pumps have a temperature control valve that is designed to fail open providing full flow through the cooler. Licensee engineers performed analysis of the affects of 32°F water on the cooler and found the results to be acceptable (the calculations are maintained by the charging pump system engineer).

Emergency Diesel Generator Jacket Cooler

The Unit 1 diesel generator is equipped with a temperature regulating valve which will automatically control the jacket water temperature by bypassing the heat exchanger. The valve is a self contained thermostatic valve which senses the generator outlet temperature to throttle the bypass valve.

The Unit 2 diesel generator jacket water temperature is controlled by an air operated throttle valve. The air supply to the valve is Cat II and can not be relied upon to be functional during an accident. The licensee plans to replace the air control valve with a self contained thermostatic valve during the next refueling outage. The station is currently operating under a Basis for Continued Operation (BCO) based on operator action to control EDG jacket water temperature manually. This BCO is planned for resolution during the upcoming refuel outage this year.

Conclusion:

The inspectors found the Updated Final Safety Analysis Reports to be accurate and the licensee's evaluation to be appropriate.

3.3 FSAR Review of Emergency Control Room Ventilation System (71707, 37551)

The inspectors reviewed Section 9.13.4, "Main Control Area," of the Updated Final Safety Analysis Report (UFSAR) and noted that the UFSAR was consistent with plant system operating and surveillance procedures and with the Unit 1 Technical Specifications (TS). Additionally, the inspectors performed a walkdown of the emergency control room ventilation portions of the control room ventilation system and the emergency pressurization system (EPS) finding no discrepancies.

The UFSAR states that the emergency pressurization system, consisting of five sets (10 bottles) of seismic Class I compressed air flasks, is designed to pressurize the control room for a period of one hour (to prevent in-leakage) to maintain control room habitability during a design basis accident. The TS surveillance test requirement (4.7.7.2.b.2) verifies the ability of the EPS to supply ≤1000 cfm of air and pressurize the control room to ≥0.125 inch Water Gauge relative to the outside atmosphere while using four out of five bottled air subsystems.

Surveillance test 3BVT 1.44.1, "Control Room Emergency Bottled Air Pressure Test," is designed to satisfy the TS requirements described above for both unit control rooms. The station last performed the 18-month surveillance in April 1994. The inspectors reviewed the results of the surveillance and had the following comments:

- The acceptance criteria for the control room pressurization portion of the surveillance agrees with the TS requirement (≤1000 cfm).
- The surveillance is performed with four out of five subsystems to simulate a single failure of the one subsystem.
- The corrected flow rate is subtracted from 800 cfm to determine the flow rate design margin. The surveillance results were well within the required air flow rates required by the UFSAR and TS.

The inspectors concluded that the station was properly testing the EPS in accordance with the UFSAR and TS.

3.4 Review of Unit 1 Design Change Package 1987 (37551)

Engineering properly evaluated Design Change Package (DCP) 1987 and developed adequate instructions to control the installation and post-installation test activities. The DCP was designed to trip the 'D' and 'E' pressurizer heater groups on a containment isolation phase 'B' (CIB) signal or quench spray (QS) pump start and also to delay the QS pump start for 5 seconds following a CIB signal.

The pressurizer heater group trip portion of the DCP was developed to increase the reliability of the 1N and 1P 480 volt busses by reducing the electrical demand on the busses. The QS pump start delay function was designed to minimize the differential pressure across the QS pump motor-operated discharge valves (MOV-QS-101A/B) (and increase its design margin) during the valve unseating period following a CIB signal.

The inspectors reviewed the 10 CFR 50.59 evaluation, a technical evaluation report (TER), the DCP installation and test instructions, and modified system electrical drawings and determined that these documents were thorough and provided good justification for the design changes. For example, the TER reviewed and the inspectors independently confirmed that the QS pump start delay time did not impact the emergency diesel generator (EDG) loading sequence. The inspectors noted that the test instructions properly tested all functions affected by the DCP. The inspectors concluded that engineering properly developed DCP 1987.

3.5 Root Cause Analysis of Transformer 2-2C Failure (62703, 37551)

The inspectors reviewed the root cause analysis of a 4kV/480V transformer failure which occurred at Unit 2 on December 18, 1995 (see NRC Inspection Report 95-21). This failure induced a plant transient and near plant trip. The report contained the failure mechanism and corrective actions to prevent recurrence.

The Maintenance Engineering and Assessment Department (MEAD) concluded that the failure of the transformer coil was due to the localized overheating of the aluminum ribbon for the 'C' phase 4kV winding. There had been no previous operating failures at Beaver Valley. Additionally, preventive maintenance checks on the transformer were successfully completed in 1992 and 1994. Although the transformer was only operating at 83% of full load capacity, the investigation identified that the temperature sensor was located in a nonconservative location which did not correspond to the transformer core temperature. The transformer cooling fans do not energize until 120° C. The peak temperature experienced during the failure was 100° C. The licensee has initiated action to lower the temperature setpoint to 90° C (which will correspond to 80% load). This action will compensate for the nonconservative location of the temperature element. Completion of this setpoint change is planned prior to July 1996.

The inspectors concluded that the root cause analysis report was thorough and that the corrective actions were being properly pursued for completion prior to the onset of peak summer heat loads in the service building.

IV. Plant Support

4.1 Radiological Controls (71750)

Posting and control of radiation and high radiation areas were inspected. Radiation work permit compliance and use of personnel monitoring devices were checked. Conditions of step-off pads, disposal of protective clothing, radiation control job coverage, area monitor operability and calibration (portable and permanent), and personnel frisking were observed on a sampling basis. Licensee personnel were observed to be properly implementing the radiological protection program.

4.2 Security (71750)

Implementation of the physical security plan was observed in various plant areas with regard to the following: protected area and vital area barriers were well maintained and not compromised; isolation zones were clear; personnel and their packages were properly searched and access control was in accordance with approved licensee procedures; security access controls to vital areas were maintained and persons in vital areas were authorized; security posts were properly staffed and equipped, security personnel were alert and knowledgeable regarding position requirements; written procedures were available; and lighting was sufficient.

4.3 Housekeeping (71750)

Plant housekeeping controls were monitored, including control and storage of flammable material and other potential safety hazards. The inspectors conducted detailed walkdowns of accessible areas of both Unit 1 and Unit 2. Housekeeping at both units was acceptable.

V. Safety Assessment and Quality Verification

5.1 Unit 1 Refueling Outage Shutdown Safety (71707, 37551)

The licensee has continued the past practice of implementing the shutdown safety philosophy of NUMARC 91-06 "Guidelines for Industry Actions to Assess Shutdown Management." NUMARC 91-06 defines the key safety functions as decay heat removal, reactor coolant inventory control, power availability, reactivity control, and containment control. A minimum level of defense-in-depth is specified for each of these key safety functions. The Operations Department, Outage Management, and the Independent Safety Evaluation Group performed a preoutage safety review using this shutdown safety guidance.

The inspectors specifically reviewed the shutdown safety planning for the key safety function of power availability. During the refueling outage, major maintenance is planned for the main unit transformer, thus it will not be available to provide backfeed power to onsite emergency buses via the unit's station system transformers. During the 'DF' (B train) emergency bus outage, the lack of backfeed capability will result in only the technical specification minimum number of AC power sources being available. The only power supplies available to the station at this time would be the 1-1 diesel generator in a standby status and the '1A' station service transformer supplying the 'AE' (A train) emergency bus. Licensee procedures require that the Plant Manager, Outage Manager, and General Manager of Nuclear Operations all approve the schedule period in which there is no level of defense above the technical specification minimum. The licensee has minimized this reduction in defense-in-depth by a number of actions. For example, the 'DF' emergency bus outage will only occur when all reactor fuel is stored in the spent fuel pool. This provides a significantly greater margin to boiling during a potential loss of power event. In the event of a failure of the running spent fuel pool pump, a contingency has been developed to cross tie the opposite spent fuel pool pump to the available train power supply. The station blackout cross tie from Unit 1 is also available as a source of AC power as a contingency for spent fuel pool decay heat removal. During the 'DF' bus outage, the licensee also imposed a no work criteria for switchyard activities. This was implemented to limit any switchyard precursor events which might jeopardize switchyard reliability.

An additional example of conservative outage planning is AC power availability during the period of reduced reactor coolant system (RCS) time to boiling:

- A diesel generator is not being released from operability conditions until 23 feet of water in the refueling cavity is established. This provides a more defense-in-depth safety posture at the beginning of the outage when decay heat loads are higher. Both diesel generators will also be returned before the cavity is drained following core reload.

- No switchyard work is permitted throughout the identified period of reduced reactor coolant system time-to boiling. This time period is from the initial isolation of all three reactor coolant loops on March 24, until the refueling cavity is filled on March 31. The ISEG has calculated a time-to boil if a loss of power event occurs. The most limiting conditions are during loop isolation (33 minutes to boil), and RCS drain below the vessel flange for detensioning of the reactor head studs (32 minutes to boil).

Overall, the inspectors found that shutdown safety management is the licensee's highest priority. The outage schedule planning ensured a greater than minimum required level of defense-in-depth was established for the key safety functions. Although this was not possible for power availability, the licensee developed contingency actions and implemented a number of precautions to minimize the likelihood of a challenge to the key safety functions. The preoutage shutdown safety review was considered by the inspectors to be of very high quality.

VI. Review of UFSAR Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR description. While performing the inspections discussed in this report, the inspectors reviewed the applicable sections of the UFSAR that related to the areas inspected. The following inconsistencies were noted between the wording of the UFSAR and the plant practices, procedures and/or parameters observed by the inspectors:

- As described in Section 1.1, chemical treatment of the Unit 2 diesel coolers is different than as described in the UFSAR.

- As described in Section 1.6, the Unit 1 UFSAR has a shorter rod drop acceptance criteria (2.2 seconds) than does Technical Specifications (2.7 seconds) and the Unit 1 UFSAR also states that rod drop testing is done at no flow cold conditions, contrary to actual practice.

- Chapter 13 of the Unit 2 UFSAR described a separate Manager of Operations for each unit and a General Manager Nuclear Operations. Since the last annual UFSAR update, DLC has combined these three positions into one with the title of General Manager Nuclear Operations. The licensee was planning to revise this chapter of the UFSAR during the next annual update.

VII. Administrative

7.1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on April 10, 1996. The licensee acknowledged the findings presented. No proprietary information was identified as being included in the report.

7.2 Management Site Visit

R. W. Cooper, Director, Division of Reactor Projects, NRC Region I, visited the site on March 21, 1996. Mr. Cooper met with J. Cross, Senior Vice

President, T. Noonan, Vice President of Nuclear Operations and Plant Manager, B. Tuite, General Manager of Operations, and C. Hawley, General Manager of Maintenance, to discuss licensee performance. Mr. Cooper also toured the site with the inspectors.

7.3 Management Meeting

On March 12, 1996, the Beaver Valley Station Senior Vice President and Chief Nuclear Officer, James E. Cross, visited the Regional Administrator, Thomas T. Martin, to discuss various topics of current interest to Duquesne Light Company and the NRC. Also in attendance were Sushil C. Jain, Vice President, Nuclear Services; Roy K. Brosi, Beaver Valley Nuclear Safety Manager; Robert M. Gallo, Region I Acting Deputy Director of Reactor Projects and Peter W. Eselgroth, Region I Chief of Reactor Projects Branch No. 7. The topics of discussion included the following: introduction of Mr. Jain to NRC Region I; maintaining adequate staffing of on-shift senior reactor operator licensed and shift technical advisor personnel; steam generator tube inspections during the upcoming outage; engineering backlog management and system engineer responsibilities; outage preparation and management; the recent emergency preparedness exercise; heightened NRC inspection emphasis on ensuring that licensee's meet the current plant design basis; proper use of performance indicators and probablistic risk assessment; and safety conservative decision making. The visit lasted about an hour.