U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No.	96-11
Docket No.	50-219 72-1004
License No.	DPR-16
Licensee:	GPU Nuclear, Incorporated 1 Upper Pond Road Parsippany, New Jersey 07054
Facility Name:	Oyster Creek Nuclear Generating Station
Location:	Forked River, New Jersey
Inspection Period:	October 21, 1996 - December 1, 1996
Inspectors:	Larry E. Briggs, Senior Resident Inspector Stephen M. Pindale, Resident Inspector
Approved By:	Peter W. Eselgroth, Chief Projects Branch No. 7

EXECUTIVE SUMMARY

Oyster Creek Nuclear Generating Station
Report No. 96-11

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers about a six-week period of inspection.

Plant Operations

- Operations had been alert to identify the need to implement a special method to shutdown the reactor and control the cooldown rate without exceeding the specified cooldown. The shutdown and subsequent restart activities were conservatively controlled. Licensee action to stop control rod movement when any one HCU alarm is received is a proactive action to prevent improper control rod movement; however, the expected action is not implemented by procedure and is subject to management change without review.

- Control room operators responded promptly and correctly to an automatic turbine runback. Operator actions to scram the reactor and following the scram were in accordance with procedures. Excellent command and control was demonstrated by the on-shift Group Operating Supervisor (GOS) during this transient. The post transient review group (PTRG) and the independent transient review group (ITRG) had performed in-depth analysis of the event but could not positively identify the cause of the turbine runback.

- The lack of a more formal work-around program was a weakness because 1) several operators were not aware of current expectations regarding how work-arounds are to be identified, tracked and resolved; and 2) only the more significant work-arounds received management attention.

- An inadequate safety determination associated with a change to procedure 336.3, "Generator Hydrogen Gas System," on February 23, 1994, resulted in failing to perform a required 10 CFR 50.59 safety evaluation, and is a violation of NRC requirements. The change modified the method by which cooling water flow was to be controlled from the generator hydrogen coolers and was contrary to the description in the UFSAR.

- Operations management was appropriately involved in providing oversight of the additional testing and troubleshooting activities following the identification of degraded acoustic monitors for two electromatic relief valves.

Maintenance

- The maintenance and surveillance activities observed by the inspectors were conducted safely and in accordance with station procedures.

Executive Summary (cont.)

- The licensee's actions following electromatic relief valve monthly surveillance test discrepancies were acceptable. The associated operability determination, performed by system engineering, was acceptable.

- Cable installation activities had been performed correctly and in accordance with written instructions.

- Poor mechanical maintenance worker practices resulted in the containment allowable leakage rate being exceeded. In this case, the event was of minor safety significance because the standby gas system was operable and would have filtered any release and radioactivity levels were normal.

- An audit conducted by Nuclear Safety Assessment of the Maintenance Program was of good quality and depth. The audit found that the maintenance program and the conduct of preventive and corrective maintenance was adequate and has been effective in preserving the material condition of the station. A particular strength identified by the audit included the presence of a strong, well-defined Self-Assessment Program. Several deficiencies were also identified by the audit, including ineffective corrective action for surveillance test related deviations, and the lack of adequate instructions regarding interim corrective actions when implementation of full corrective actions may be long term.

- A self-assessment of the Minor Maintenance (MM) process was a good initiative, and the quality of the product was good. The report concluded that MM was being performed in accordance with station procedures. Minor discrepancies were identified, and included inconsistent filing of completed MM job orders. No significant deficiencies were identified.

Engineering

- The licensee had appropriately evaluated the reinjection of reactor water cleanup system valve V-16-63. The licensee kept all parties (NRC) appropriately informed of their actions and plans concerning this valve.

- The licensee had performed very thorough troubleshooting in an attempt to identify the cause of an automatic turbine runback. They had completely instrumented the runback circuit to monitor and identify the faulty runback circuit components. Proper evaluations had been performed for removal of the runback circuit prior to its removal. Engineering provided strong support for plant operations.

- Engineering provided good support to maintenance personnel during emergency diesel generator (EDG) cable installation activities to ensure proper performance. Engineering also ensured that sufficient data was obtained to verify that the No. 1 EDG cables would not be a problem during the next run cycle.

- Engineering personnel provided strong support in investigating the thermal power oscillations and associated balance of plant operational anomalies. Their efforts were successful in partially dampening the thermal power oscillations. Continuing evaluation activities were in progress at the end of this inspection.

- Engineering provided strong support to operations in the implementation of an action plan to identify and correct the containment leakage that was found to have been in excess of technical specification limits. Operations was also alert in the identification of what appeared to be excessive N2 use in the drywell.

- An audit conducted by the Nuclear Safety Assessment of the Plant Support Engineering Audit Report was of acceptable detail and quality. The licensee's Engineering organization made good use of audit resources by selecting areas for review, such as plant performance monitoring, plant modifications using 125-1 forms (engineering evaluation forms), effectiveness of communicating Engineering direction to Maintenance, and 10 CFR 50.59 reviews of 125-1 forms. The audit did not identify any significant deficiencies, although it was noted that Engineering support on immediate problems was good, but not as good when required support was not urgent. The detail and quality of the audit was acceptable.

Plant Support

- The licensee effectively implemented the radiation protection and security programs.

- An audit conducted by Nuclear Safety Assessment was of sufficient detail and quality. The audit found that the Chemistry Program at Oyster Creek has been effectively implemented. No significant findings were identified. Use of the chemistry process performance team reviews to satisfy Procedure 106.6 audit requirements was a reasonable and acceptable practice.

TABLE OF CONTENTS

Table of Contents (cont.)

Report Details

Summary of Plant Status

At the beginning of this report period, the plant was critical (plant startup commenced on October 20, 1996) and the licensee was in the process of conducting the 1000 psig inspection of the reactor coolant system following the 16R outage. The licensee returned the plant to a shutdown condition on October 21, 1996, to repair a valve in the steam system that had a body-to-bonnet leak. On October 22, 1996, following the valve repair, the plant was restarted. The main generator was connected to the grid at 9:57 p.m. on October 23, 1996, officially ending the 16R refueling outage. The plant was manually scrammed on October 25, 1996, after an automatic main turbine generator runback occurred due to a problem in the stator cooling system. On October 27, 1996, while the plant was shutdown, a ground fault in the 4160 volt cable from the No. 2 emergency diesel generator caused a loss of the "D" 4160 volt safety bus. A new cable was installed and the plant was restarted on November 6, 1996. The main generator was connected to the grid on November 7, 1996, and the plant reached full power at 10:40 a.m. on November 8, 1996. Full power continued for the remainder of the reporting period.

I. OPERATIONS

O1 Conduct of Operations[1]

O1.1 General Comments (71707)

The inspectors conducted frequent reviews of ongoing plant activities and operations using the guidance in NRC inspection procedure 71707. The inspectors observed plant activities and conducted routine plant tours to assess equipment conditions, personnel safety hazards, procedural adherence and compliance with regulatory requirements.

Control room activities were found to be well controlled and were conducted in a professional manner. Staffing levels were above those required by Technical Specifications. The inspectors verified operator knowledge of ongoing plant activities, the reason for any lit annunciators, safety system alignment status, and existing fire watches. The inspectors also routinely performed independent verification from the control room indications and in the plant to determine that safety system alignment was appropriate for the plant's current operational mode.

---

[1]Topical headings such as O1, M8, etc., are used in accordance with the NRC standardized reactor inspection report outline. Individual reports are not expected to address all outline topics.

O1.2 Plant Shutdown and Restart Observations

a. Inspection Scope (71707)

The inspector observed portions of the plant shutdown that occurred on October 21, 1996. The shutdown was initiated to repair a body to bonnet steam leak on a second stage reheater pressure regulating valve (V-1-312). The inspector also observed portions of the plant restart on October 22, 1996, following repairs to V-1-312.

b. Observations and Findings

On October 21, 1996, the licensee commenced a shutdown of the reactor to implement repairs to the body to bonnet leak on V-1-312. Just prior to the shutdown, the licensee determined that the low power history on the reactor would not provide adequate decay heat to prevent an excessive cooldown rate. Technical Specification (TS) requires cooldown and heatup rates to be maintained 100° F per hour, or less, under normal conditions. Operations management and core engineering briefed the operating crew and initiated a procedure change to perform a "critical plant cooldown." The licensee performed a 10 CFR 50.59 safety determination to determine if a full written safety evaluation was required. A full evaluation was not required. The licensee's safety determination noted that the change did not change the facility or its operation as described in the Updated Final Safety Analysis Report (UFSAR) Chapter 4, Reactor, or TS, Section 3.3, "Reactor Coolant." The inspector independently reviewed the above referenced UFSAR and TS Sections, as well as UFSAR, Section 5, "Reactor Coolant System and Connected Systems." The inspector verified that the procedure change did not change the facility or its operation as described in the UFSAR. The reactor power level during cooldown and heatup is not addressed in the UFSAR, cooldown and heatup rates are discussed. The intent of the procedure change was to control cooldown rate within the required value of 100° F per hour or less.

The procedure change directed the control room operators to insert control rods to maintain the desired cooldown rate. This allowed plant cooldown to be controlled by reactor power and heat input. The method of cooldown was the only change to Procedure 203.2, "Plant Cooldown from Hot Standby to Cold Shutdown." The inspector observed the plant shutdown and cooldown and noted that operators were controlling the cooldown rate acceptably at about 60° F to 70° F per hour. The plant shutdown and cooldown was completed, with the reactor in cold shutdown at 8:27 p.m. on October 21, 1996.

---

[1]Topical headings such as O1, M8, etc., are used in accordance with the NRC standardized reactor inspection report outline. Individual reports are not expected to address all outline topics.

On October 22, 1996, following repairs to V-1-312, the licensee performed a reactor plant startup. The inspector observed a portion of the startup and plant heatup. The startup proceeded in accordance with applicable plant and system procedures, and supervision demonstrated good command and control of plant activities. The inspector noted that all control rod activity was suspended when one hydraulic control unit (HCU) low pressure alarm annunciated. The operations director stated that this action was a new conservative reactivity management effort to prevent improper rod movement. A previous incident, prior to shutdown for 16R, involved control rod movement of one notch in the wrong direction. The incorrect movement was thought to have been caused when a rod block (due to second HCU alarm) was received simultaneously with a withdrawal signal. When the rod block occurred, it stopped the outward direction control sequence. And since the rod normally moves inward to unlatch the collet fingers, the suspension of the out direction control sequence caused the rod to simply settle one notch further inserted in the core. Since it takes two HCU alarms to give a rod withdrawal block, the termination of rod movement when one is received provides a margin to prevent possible improper control rod movement. This action was implemented verbally as a "management expectation." This was discussed with several operations personnel and all understood the verbally expressed instructions.

At about 6:40 p.m. on October 22, 1996, the licensee began the 1000 psig inspection of the drywell. Due to body-to-bonnet leakage on V-16-63, the 6 inch, manual isolation valve from the reactor water cleanup system to the "B" recirculation loop, the licensee decided to perform a sealant injection to reduce the leakage. The leak repair was completed about 1 a.m. on October 23, 1996. This activity is discussed in Section E1.1. Following valve repair, the drywell was closed in preparation for plant power ascension.

At 9:57 p.m. on October 23, 1996, following turbine testing, the turbine generator was connected to the Grid, officially ending the 16R outage. The plant reached full power at 4:56 a.m. on October 25, 1996. The turbine generator experienced a runback at 11:59 a.m. that morning that resulted in a manual reactor scram, discussed in Section O1.3, below.

c. Conclusions

The inspector determined that operations had been alert to identify the need to implement a special method to shutdown the reactor and control the cooldown rate without exceeding the specified cooldown. The shutdown and subsequent restart activities were conservatively controlled. Licensee action to stop control rod movement when any one HCU alarm is received is a proactive action to prevent improper control rod movement; however, the expected action is not implemented by procedure and is subject to management change without review.

O1.3 Manual Reactor Scram Due to Turbine Generator Runback

a. Inspection Scope (71707, 93702)

The inspector reviewed the circumstances surrounding the October 25, 1996, manual scram.

b. Observations and Findings

On Friday, October 25, 1996, control room operators manually scrammed the reactor after a turbine runback occurred. The manual scram was performed in accordance with plant procedures. All plant systems responded normally on the scram with the exception of one control rod that settled at notch position 02 vice 00. The inspector observed control room personnel actions following the reactor scram. Operators were alert to plant conditions and following appropriate procedures in a professional manner. The group operating supervisor (GOS) demonstrated excellent command and control of control room activities. Initial plans were to keep the plant in hot shutdown, determine the cause of the turbine runback and restart the reactor without going to cold shutdown. However, the licensee's actions to identify the cause of the turbine runback were unsuccessful and the plant was placed in cold shutdown on October 26, 1996. Troubleshooting activities by the licensee are discussed in Section E2.1.

The licensee formed a "post transient review group" (PTRG) to review plant data to verify systems performed as expected and to identify the cause of the turbine runback. As noted above, an exact cause could not be determined. The PTRG recommended that an "independent transient review group" (ITRG) be formed to further review the transient to assist in the determination of the cause of the turbine runback. Neither group could positively identify the cause of the runback. The most likely cause was the recently (16R refueling outage) stator cooling temperature switches may have unexpectedly actuated.

The licensee checked the three stator cooling temperature switches. Although calibration data showed some drift from the previous as-left calibration, the switch with the most drift still had a setpoint 18° C above the actual recorded temperature of the stator coolant at the time of the runback. Subsequent troubleshooting and monitoring by the licensee had confirmed the temperature switches as the cause of the turbine runback.

On Saturday, October 26, 1996, the inspector reviewed the licensee's troubleshooting activities to verify that all possible checks had been made to identify the cause of the turbine runback. The licensee's troubleshooting was thorough. On October 27, 1996, at 11:59 p.m. while making final preparations for plant restart, the 4160 volt cable between the 1D 4160 volt bus and the No. 2 emergency diesel generator output breaker failed. The plant remained shutdown until November 6, 1996, while a new cable was installed. Cable installation is discussed in Section M1.5 of this report.

c. Conclusions

The inspector determined that control room operators had responded promptly and correctly to the turbine runback. Operator actions to manually scram the reactor and in response to the scram were in accordance with procedures. Excellent command and control was demonstrated by the on-shift GOS during this transient. The PTRG and the ITRG had performed in-depth analysis of the event, but could not positively identify the cause of the turbine runback.

O1.4 Licensee Identification and Followup of Operator Challenges (Operator Work-Arounds) **(Violation 96-11-01)**

a. Inspection Scope (71707)

The inspector reviewed the classification and status of "operator work-arounds," and assessed selected individual work-arounds. In general, an operator work-around represents a degraded condition that prevents the normal operation of a structure, system, or component, and is compensated for by operator action. The inspector reviewed the documents that identify and track operator work-arounds and interviewed several operations staff personnel.

b. Observations and Findings

The licensee currently does not have a formal and documented program for work-arounds, however, they are developing a work standard that will formalize the process. For about a year, the licensee had maintained a list of operator work-arounds. That list had received management attention and had been reviewed on a weekly basis during the Plan of the Day meetings.

The inspector found that the operator work-arounds were typically of relatively high threshold. For example, automatic operation of the feedwater control system at low power and the operation of the thermal dilution gates at the main intake structure (to prevent ice formation) were both on the list. Both represented challenges to the operators with respect to potential plant or system impact and/or resource impact in achieving desired results. The Director of Plant Operations informed the inspector that the new standard will address less significant work-arounds as well as the highly visible ones. The existing work-around list (at the end of the inspection period), included some of the less significant work-arounds. It was apparent that an effort was underway to make the work-around list more inclusive of all degraded conditions that represent system or operator challenges.

The inspector interviewed several operations personnel. Not all were familiar with the work-around process (including the work-around list and status) or with management's expectations regarding work-arounds.

During the operations personnel discussions, another potential work-around was identified in which an automatic temperature control valve in the turbine building closed cooling water (TBCCW) system supply for the main generator hydrogen coolers had been disabled for many years. The inspector found that the operators desired the valve to remain in a failed open position (and control cooling flow manually) because they had little confidence in proper automatic system operation. The inspector found that the UFSAR (Section 9.2.1.5.2), "TBCCW System Description," stated, in part, that *except* for the hydrogen coolers TBCCW flow, which is adjusted by a temperature regulated air control valve, all valving is *manual*.

Manual control of the TBCCW flow to the hydrogen coolers is described by station procedure 336.3, "Generator Hydrogen Gas System." The inspector reviewed the associated change review document (Revision 18) for the procedure change that was implemented on February 23, 1994. Question 5 on the safety determination form questioned whether implementation of the proposed change required a revision of any procedural or operating description in the SAR. It was answered as no, and stated that the revision does not affect UFSAR Section 8.0. The inspector determined that this was answered incorrectly as Section 9.2.1.5.2 of the UFSAR described only automatic operation of the valve. The safety significance of this error was relatively low, however, it resulted in operating/controlling the system in a manner different than the UFSAR. Moreover, operating the system in manual potentially requires operator intervention during load reductions (due to lower temperatures in the main generator) or if temperature and/or pressure changes were to occur within the TBCCW system.

If question 5 in the safety determination was answered yes as it should have been, a written 10 CFR 50.59 safety evaluation would have been required to determine whether an unreviewed safety question existed. The failure to perform the required 10 CFR 50.59 safety evaluation is a violation. **(VIO 50-219/96-11-01)**

c. Conclusions

The lack of a more formal work-around program is a weakness because 1) several operators were not aware of current expectations regarding how work-arounds are to be identified, tracked and resolved; and 2) only the more significant work-arounds received management attention. An inadequate safety determination associated with a change to procedure 336.3 on February 23, 1994, resulted in failing to perform a required 10 CFR 50.59 safety evaluation, and is a violation of NRC requirements.

O8 Miscellaneous Operations Issues (90712, 90713)

O8.1 (Closed) Licensee Event Report 96-08: Manual Reactor Scram Due to a Main Generator Runback. This LER discussed a plant transient that was initiated by an invalid actuation of temperature sensing switches in the main generator runback circuit. The event is discussed in detail in Section O1.3 of this report. This LER is closed.

O8.2 Special & Periodic Report Review:

- Special Reports 96-01 (September 5, 1996) and 96-01, Revision 1 (October 15, 1996) were reviewed by the inspector. The inoperability of the high range radioactive noble gas effluent monitor (stack RAGEMS) since August 6, 1996, was the subject of the reports. The licensee found the monitor to be inoperable due to a failed power supply and a failed rate meter. The system was satisfactorily tested and returned to service on October 9, 1996. The stack RAGEMS monitor's preplanned alternate sampling system (the post-accident sampling system) remained operable during the time period that stack RAGEMS was inoperable. The inspector determined that the special report was acceptable.

- Monthly operating reports for July, August, September, and October, 1996, were reviewed and found to be acceptable.

II. MAINTENANCE

M1 Conduct of Maintenance

M1.1 Maintenance Activities

a. Inspection Scope (62707)

The inspectors observed selected maintenance activities on both safety-related and non-safety-related equipment to ascertain that the licensee conducted these activities in accordance with approved procedures, Technical Specifications, and appropriate industrial codes and standards. The inspectors observed all or portions of the following job orders (JO):

- JO 509348, Reinject Valve (V-16-63) During Power Ascension
- JO 509761, Install Lighting Upgrades at Intake Structure
- JO 510961, Replace 4160 Volt Cable (EDG 2 to "D" 4160 Safeguards bus)

b. Observations and Findings

The inspectors concluded that the above activities had been approved for performance and were conducted in accordance with approved job orders and applicable technical manuals and instructions. Personnel performing the activities were knowledgeable of the activities being performed and were observing appropriate safety precautions and radiological practices.

M1.2 Surveillance Activities

a. Inspection Scope (61726)

The inspectors performed technical procedure reviews, witnessed in-progress surveillance testing, and reviewed completed surveillance packages. They verified that the surveillance tests were performed in accordance with Technical Specifications, approved procedures, and NRC regulations. The inspectors reviewed all or portions of the following surveillance tests:

- 617.4.003, Control Rod Scram Insertion Time Test and Valve Inservice Test
- 607.4.004, Containment Spray and Emergency Service Water System 1 Pump Operability and Inservice Test
- 610.3.006, Core Spray Isolation Valve Actuation Test and Calibration

b. Observations and Findings

A properly approved procedure was in use, approval was obtained and prerequisites were satisfied prior to beginning the test. Surveillance test instrumentation was properly calibrated and used, radiological practices were adequate, technical specifications were satisfied, and personnel performing the tests were qualified and knowledgeable about the surveillance test procedure.

M1.3 Routine Maintenance and Surveillance Activities Conclusions

The maintenance and surveillance activities observed by the inspectors were conducted safely and in accordance with station procedures.

M1.4 Electromatic Relief Valve Acoustic Monitor Anomaly

a. Inspection Scope (61726, 37551, 71707)

On November 16, 1996, while conducting the monthly main steam line safety relief valve and electromatic relief valve (EMRV) acoustic monitoring system monthly test (procedure 602.3.008), two of the five EMRVs failed to meet the acceptance criteria for their primary acoustic sensor. The inspector reviewed the licensee's immediate and subsequent followup actions associated with this event, including compliance with technical specifications and the associated operability determination.

b. Observations and Findings

The "C" and "D" EMRVs failed to achieve adequate resonant frequency during the monthly test. As a result, the installed backup acoustic monitors for those valves were connected, replacing the primary monitors. The "D" backup channel functioned properly and was retested satisfactorily. However, the "C" EMRV backup channel appeared to be slightly degraded in that it exhibited a low bias condition and a low overall signal gain characteristic. In addition, although a diagnostic trace for the "C" EMRV indicated a resonant frequency, extraneous signals ("noise") were superimposed on the typical waveform.

Each of the five EMRV acoustic monitoring channels have a corresponding audible system channel in the control room, which provides the operators the ability to listen to a baseline audible signal as a verification that the associated channels are operating.

In response to the apparent degradation of the "C" EMRV acoustic monitor, the licensee conducted additional troubleshooting and completed an operability determination. To ensure proper operation of the acoustic monitor, the licensee functionally tested the "C" EMRV by using existing procedures. During that test (procedure 602.4.003, "EMRV Operability Test"), the signal conditioner high alarm light illuminated, the EMRV Not-Closed alarm annunciated, the audible speaker indicated increased flow (high volume) and then flow stoppage (nominal volume), and the front panel indicator displayed open. These actions all occurred as expected, which indicated that the "C" EMRV backup acoustic monitor performed its intended function.

The associated operability determination documented the test results and provided the bases for continued operability for the "C" acoustic monitor. Specifically, the low bias alarm was not annunciated, the resonant frequency was observable, and the audio speaker test indicated nominal steam flow (background noise). In addition, the operators were instructed to listen to the audible speakers associated with all five EMRVs and all nine safety valves to confirm continued operability (on a daily basis). This action was directed to allow continued monitoring of the acoustic monitoring system.

The licensee did not know the reason for both primary EMRV acoustic channels becoming inoperable. The clamping device for the local sensors were replaced during the recent outage. The daily checks will continue to ensure a common cause problem is not evident. Since the operators continued to conduct the daily checks, the licensee identified this issue on the current operator work-around list, and targeted the next unplanned shutdown to investigate and repair the degraded condition (drywell entry required).

c. Conclusions

The inspector concluded that the licensee's actions following the surveillance test discrepancies were acceptable. Operations management was appropriately involved in providing oversight of the additional testing and troubleshooting activities. The inspector determined that the operability determination, performed by system engineering, was acceptable.

M1.5 Replacement of 4160 Volt AC Cable

a. Inspection Scope (62707)

The inspector observed portions of the licensee's activities during the replacement of the 4160 volt cable that failed at 11:59 p.m. on October 27, 1996. The cable runs from the No. 2 emergency diesel generator (EDG) output breaker to the "D" 4160 safeguards bus. The cable experienced an in-service failure while the licensee was making final preparations for plant restart following the October 25 manual reactor scram. There were no loads on the cable at the time.

b. Observations and Findings

Preparations for the cable pull began on October 28, 1996, and the cable pull was completed, including cable testing, on November 3, 1996. The cable run from the No. 2 EDG output breaker consists of two conduits with cable phases A, B, and C in each conduit. The cable that failed was a 1977 vintage cable (C phase). The other conduit's cables had been replaced in 1994, during the 15R outage. The inspector monitored selected portions of the various activities associated with the cable pull, such as removal of the old cable, cleaning of the conduit, pulling of the new cable, and review of the results of meggar and hi-pot testing. The inspector also reviewed the pull tension calculations and found them acceptable. During the initial pull to the No. 2 EDG from the turbine building basement, the licensee exceeded the pull tension when the ground wire pull connector became lodged in the conduit. The licensee pulled all three phases of the new cable out, cut off about 85 feet of the cable (the length that had been pulled into the conduit), and started over. The subsequent cable pull was performed without incident.

The inspector questioned the licensee concerning the bend radius allowed for this cable when they were making preparations for the pull into the 4160 volt room from the turbine building basement. The licensee was making preparations to pull the cable over a 18 inch diameter pulley due the tight space. This small pulley gives a bend radius of 9 inches. The licensee later changed to a 24 inch diameter pulley. Information (ICEA/NEMA STDS.) was provided to the inspector that indicated that this cable could have a minimum bend radius of 5 times the cable outside diameter. The outside diameter of the cable was 1.24 inches. That allowed a minimum bend radius of about 6 and 1/4 inches.

Following installation of the new cable several electrical tests were preformed. The three new cables were meggar tested at 5000 volts DC and polarity indexes derived (one minute leakage current divided by five, ten, etc., leakage currents) and hi-potted to 35 kilovolts. All readings were acceptable. The three cables in the other conduit received similar tests and were hi-potted to 25 kilovolts. Results were acceptable. Following No. 2 EDG return to service, the No. 1 EDG was removed from service and its cables were meggar tested at 1000 and 2500 volts DC, with polarity indexes obtained at the one and ten minute intervals. All readings were acceptable.

The inspector also verified that all new cable was from the same procurement time frame and from the same vendor. All new cable was from Procurement Quality Assurance No. 447522, with the same dates of receipt. The cable was "Cablec" EP insulated cable.

c. Conclusions

The inspector concluded that the cable installation had been performed correctly and in accordance with written instructions. Engineering provided good support to maintenance personnel to ensure that this high priority activity was performed correctly. Engineering also ensured that sufficient data was obtained to verify that the No. 1 EDG cables would not be a problem during the next run cycle.

M7 Quality Assurance in Maintenance Activities (40500)

M7.1 Nuclear Safety Assessment Audit of the Maintenance Program

The inspector reviewed Maintenance Program Audit Report S-OC-96-14 (May 31, 1996, Memorandum) that was conducted by Nuclear Safety Assessment. The results of the audit found that the maintenance program and the conduct of preventive and corrective maintenance was adequate and has been effective in preserving the material condition of the station. A particular strength identified by the audit included the presence of a strong, well-defined Self-Assessment Program. Several deficiencies were identified by the audit, including ineffective corrective action for surveillance test related deviations, and the lack of adequate instructions regarding interim corrective actions when implementation of full corrective actions may be long term. Audit personnel submitted deviation reports for the individual deficiencies that they identified. The inspector concluded that the audit was of acceptable depth and quality.

M7.2 Maintenance Self-Assessment of Minor Maintenance

By report dated June 30, 1996, the maintenance department completed self-assessment report 96-04, which reviewed minor maintenance (MM) activities for calendar year 1995. The report concluded that for the 100 closed MM job orders reviewed, MM was being performed in accordance with station procedures. Minor discrepancies were identified, and included inconsistent filing of completed MM job orders. No significant deficiencies were identified. The inspector concluded that the licensee's effort to conduct this self-assessment was a good initiative, and the quality of the product was good.

M8 Miscellaneous Maintenance Issues (90712)

M8.1 (Closed) Licensee Event Report 96-11: Primary Containment Leak Rate in Excess of Technical Specification Requirements Due to Incorrect Re-assembly of Valve Cover. A torus to drywell vacuum breaker valve cover was found to be leaking due to inadequate maintenance in which the valve cover was misaligned during valve re-assembly during the recent refueling outage. Primary containment leakage was calculated to be about two times the amount allowed by technical specifications. See Section E2.3 of this report for additional details on this event.

M8.2 Discovery of Four Support Bolts for Vital DC Motor Control Center Missing: On November 13, 1996, the licensee discovered and immediately reported to the NRC that four bolts were discovered missing on a vital DC motor control center (MCC). The licensee's engineering staff determined that without the bolts the support was inadequate in a seismic event. As a result the MCC and the "B" isolation condenser was declared inoperable. The "B" isolation condenser has two motor operated valves the were powered from this MCC. This placed the plant in a 30 hour shutdown LCO action requirement, in accordance with Technical Specification 3.7, Auxiliary Electrical Power. The licensee replaced the missing bolts and returned the MCC and isolation condenser to service at 6:25 P.M. on November 13, 1996, less than four hours after discovery.

The bolts were removed during the recent 16R outage to perform cable replacement work related to Generic Letter 89-10, Safety Related Motor-Operated Valve Testing and Surveillance. The job order did not provide specific details concerning removal and reinstallation of the bolts. The activity was considered within the "skills-of-the-craft." The maintenance workers and their immediate supervisor did not exhibit sufficient attention to detail during the final walkdown of the MCC following completion of work.

The inspector determined that this occurrence was due to personnel error and inadequate supervisory oversight of contractor personnel. The safety significance of this occurrence was minimal because the other isolation condenser was fully operational and there was a minimum of power history on the new reactor core which would result in a small decay heat load. Licensee response on discovery was very prompt and effective.

III. ENGINEERING

E1 Conduct of Engineering

E1.1 Leak Seal Injection of Six Inch Isolation Valve (V-16-63)

a. Inspection Scope (37551, 71707)

The NRC resident staff, NRC Region 1, and NRC Nuclear Reactor Regulation (NRR) reviewed the licensee's calculations and plans to perform a sealant injection repair to the manual six inch reactor water cleanup (RWCU) return line isolation valve. The valve is the return of the RWCU flow to the "B" reactor recirculation (RR) loop and is not isolable from the "B" RR loop. In addition, the inspector observed the licensee perform the sealant injection on October 22, 1996, in the primary containment during the 1000 psig drywell inspection.

b. Observations and Findings

This valve was initially injected with sealant following the 15R outage in late 1994. It had performed satisfactorily following that injection, during the operating cycle. During the week of October 15, 1996 the licensee performed the 1000 psig hydrostatic test. Licensee observations during that test indicated that V-16-63 was leaking several ounces per minute and would possibly require a leak repair during the 1000 psig drywell inspection. Since the 1000 psig hydrostatic test is not performed hot, the possibility existed that the valve might seal during the subsequent 1000 psig drywell inspection since plant temperatures are at 535 to 545 F during that inspection.

The licensee had originally scheduled this valve for permanent repair during the recent 16R outage. It was scheduled for early in the outage; however, outage risk management had determined that risk was excessive due to projected plant conditions when the activity was scheduled to be performed. Risk management wanted to move the repair activity, which involved using a freeze seal to provide a boundary between the RR loop and the valve, to the end of the outage when the reactor vessel was reassembled and containment was established. This would have required about 3 additional days of critical path outage time. A second option was to inspect the valve during the 1000 psig hydrostatic test and again during the 1000 psig drywell inspection and to reinject the valve if necessary. The second option was chosen.

In preparation for the possibility of a leak repair, the licensee performed Safety Evaluation 000215-011. This evaluation, the vendor's (Team Environmental Services - "TES") injection procedure and calculations, a risk outage assessment memorandum, and the licensee's job order were sent to the NRC Region 1 and NRR for review. The licensee's plans were also discussed in a telephone conversation between NRC Region 1, NRR and the resident staff. The NRC agreed with the licensee's plan of action to inject the valve, vice attempting repair using a freeze seal, as the safest approach to the repair.

On October 22, 1996, the licensee decided to inject V-16-63 to reduce the observed leakage rate, about 4 ounces per minute. TES had calculated the injectable void in the valve to be 0.269 cubic inches. The valve body had previously been drilled and fitted with four injection valves, two of which had been injected to seal the valve in late 1994. During the initial entry to inject the valve, a previously injected port could not be opened. The other injected port was redrilled but did not provide a sufficient open access to the leakage space. A previously undrilled injection port was drilled and injected (five strokes) with sealant. This reduced the leakage somewhat but did not reduce it to an acceptable level. Subsequent discussion between the vendor and NRC indicated that the compressibility factor was 1.5 for the 2X sealant being used. The vendor calculated that 7 1/2 strokes of the hand pump would inject the proper amount into the valve seal area. The vendor on the next entry was instructed to try and reopen the previously (1994) injected port since it was closest to the leakage observed. The inspector observed the vendor, being supervised by the licensee, redrill and inject the previously drilled and injected port with seven strokes of the injection pump, which did not stop the leakage. The vendor drilled and injected the last partially drilled port and injected seven strokes of sealant into that port also. Leakage slowed to about 2 to 3 drops per minute. Licensee management decided that leakage was reduced to an acceptable level and directed that the drywell be closed following the completion of the 1000 psig drywell inspection.

Plant startup and power escalation continued until October 25, 1996, when a manual reactor scram was initiated due to a turbine runback (Section O1.3).

While the plant was shutdown, the licensee made plans to reinject V-16-63 if it should be necessary. This was discussed with the NRC Region 1, NRR, and the resident staff during a telephone conference call on October 31, 1996. All parties agreed that reinjection, if necessary, was appropriate and the safest course of action. During the licensee's 1000 psig drywell inspection the leakage from V-16-63 remained at 2 to 3 drops per minute and licensee management decided not to reinject V-16-63.

c. Conclusions

The inspector concluded that the licensee had appropriately evaluated the reinjection of V-16-63. The licensee kept all parties (NRC) appropriately informed of their actions and plans concerning this valve. Due to the valve design (pressure seal) the possibility of damage to the valve due to injection of sealant was highly unlikely.

E2 Engineering Support of Facilities and Equipment

E2.1 Engineering Support of Troubleshooting of the Turbine Generator Runback Circuit

a. Inspection Scope (37551)

On Saturday, October 26, 1996, the inspector reviewed the scope and results of troubleshooting activities conducted by the licensee to identify the cause of the turbine generator runback that occurred on October 25, 1996.

b. Observations and Findings

Prior to the 16R outage, a turbine generator runback circuit consisted of two circuits of one-out-of-one logic actuation. The two circuits were stator coolant temperature and stator coolant low flow (sensed by a pressure switch in the stator coolant system). Temperature indication is provided by separate sensors. The licensee modified the two runback circuits to two-out-of-three logic circuits as part of their scram reduction program during the 16R outage. The main turbine generator runback can be initiated from two signals, either high temperature at 89° C or low stator cooling flow (sensed by discharge pressure switch), corresponding to about 230 gallons per minute (GPM).

The licensee had experienced an automatic scram due to high reactor pressure on December 1995, initiated by a problem in the stator cooling system that initially resulted in a turbine runback. However, the stator cooling system problems in December 1995 were from completely different circumstances than those experienced on October 25, 1996.

Following the manual reactor scram, the licensee performed troubleshooting of the turbine runback circuit, including calibration checks of all six sensors. One of the temperature switch's "as found" trip point was 82° C, which was 7° C lower than the nominal setpoint (89° C). This was the most drift of any of the six instruments checked, and its trip setpoint was still about 18° C above the actual temperature of the stator cooling system. Pressure switches were found within the tolerance band. Other testing by the licensee included all logic combinations with actual relay energizing and de-energizing functions checked. The licensee had also performed wire checks of the relays and switches. No faults that could have caused the runback were identified. The inspector reviewed the runback schematic drawing and discussed the licensee's troubleshooting activities and possible additional tests. The licensee noted that the testing questioned by the inspector had already been conducted during previous troubleshooting activities with no conclusive results. The inspector was satisfied that the licensee had fully tested the turbine runback circuit.

Since the licensee was unable to identify the cause of the turbine runback, they fully instrumented the turbine runback circuit prior to plant restart on November 6, 1996. Instrumentation consisted of three recorders and one contact annunciator. The equipment monitored all temperature and pressure switches, stator cooling system pressure, stator cooling pumps, runback signal status, and runback relay status. The instrumentation also provided an additional local alarm and an input into the stator trouble common alarm in the control room. The alarm would be received when any single temperature or pressure switch actuated. The instrumentation was installed under temporary modification 96-101. The modification did not affect the operation of any of the installed instrumentation.

Following restart on November 6, 1996, the licensee received two stator cooling trouble alarms, one on the 14th and one on the 15th of November. Each time, the licensee locally observed that a temperature switch had moved to the actuated position, although the stator system was functioning normally at the time the alarms were received. After the first alarm, the faulty temperature switch was removed (bypassed) from the circuit and the logic became two-out-of-two to initiate a turbine runback on temperature. After the second alarm due to a second faulty switch, the turbine runback temperature portion of the circuit was disabled. The circuit was disabled under temporary modification 96-105 on November 15, 1996. The inspector reviewed the modification package and determined appropriate reviews and evaluations had been conducted and that acceptable compensatory action was directed, including increased monitoring of stator temperatures and stator cooling system function. In addition to the temperature switches in the runback circuit, there are additional temperature sensors that provide indication and a high temperature alarm in the control room at 48° C (stator inlet temperature) and 84° C on the stator outlet temperature. Licensee actions in the event of a high temperature (increasing) are the same; manually scram the reactor if above 30 percent reactor power.

The three new temperature switches installed during 16R were Mercoid switches with liquid filled thermobulbs, capillary and bourdon tubes that were similar in design to the original single temperature switch. The replacement switches are Dresser/Ashcroft with gas filled thermobulbs and a bellows type switch actuator. The new switches were installed on December 2, 1996, and monitored until December 5, 1996, when they were reconnected into the runback circuit.

When questioned concerning why the original switch had never given any false turbine runbacks, the licensee determined that the original switch had a long capillary tube that had been run from its sensing point up into the overhead then down to the switch. The replacement switches had shorter capillary tubes and were run along the mounting base of the stator cooling expansion tank. The mounting base was subject to some fluctuations in temperature due to surges into and out of the expansion tank which caused the temperature sensitive liquid filled capillary tube to falsely actuate the temperature switches. The sensitivity was verified by tests using a hot air gun. Likewise, the insensitivity of the new (gas filled switches) was also verified by tests with the hot air gun prior to their installation.

c. Conclusion

The inspector concluded that the licensee had performed very thorough troubleshooting in an attempt to identify the cause of the turbine runback. They had completely instrumented the runback circuit to monitor and identify the faulty runback circuit components. Proper evaluations had been performed for removal of the runback circuit prior to its removal. Engineering provided strong support for plant operations.

E2.2 Thermal Power Oscillations

a. Inspection Scope (37551, 71707)

Since plant startup from the recent 16R refueling outage (October 23, 1996), the control room operators have noticed small thermal power oscillations. The inspector reviewed the licensee's actions in identifying and addressing potential causes for the oscillations.

b. Observations and Findings

Control room operators observed that the computerized trend displayed in the control room for reactor thermal power indicated small oscillations on a continual basis. The maximum peak-to-peak value was about 10 MW_t, and completed a full cycle in about four to five minutes. In response to the observed phenomenon, plant staff (engineering, operations, and maintenance personnel) evaluated the condition.

Also, the control room operators maintained nominal reactor power slightly less than the licensed limit of 1930 MW_t such that the peak of the oscillations did not exceed 1930 MW_t.

The licensee suspected various causes for the oscillations, including minor perturbations in the condensate/feedwater system or a response to system control parameters or electrical "noise" from the feedwater control system. Their initial efforts were focused on investigating condensate system fluctuations, and in particular, the main condenser hotwell level control system.

Condenser hotwell level control is accomplished via two sets of valves for condensate makeup and rejection. Each set of valves consists of a small (2 - 4 inch) control valve and a large (8 - 10 inch) control valve (arranged in parallel). The makeup valves draw water from the condensate storage tank (CST) and provide water directly to the three condenser hotwells via vacuum drag. The reject valves direct excess water volume from a point in the condensate system downstream of the hotwells and the condensate demineralizers, and direct the water flow back to the CST. There is also an additional connection between the condensate system and the control rod drive (CRD) system. Specifically, a three inch line, the CRD water quality line, provides a source of clean, dearated water to the suction of the CRD pumps (and the CST) via regulating valve V-2-124 (90 gpm total flow; about 70 gpm going to the CRD pumps, and about 20 gpm being diverted back to the CST).

The licensee developed and implemented several troubleshooting action plans to investigate whether selected hotwell level control valves were leaking, resulting in excessive operation of other control valves. This excessive operation was believed to have contributed to minor system fluctuations, and thereby caused the feedwater control system to respond in the observed cyclic manner (power oscillations). The licensee also monitored the CRD quality line to determine whether proper flow was being supplied.

As a result of the troubleshooting, the licensee identified the following. Due to either some type of line blockage or misoperation by V-2-124, there was no flow through the water quality line. As a result, less water was being removed from the condensate system (about 20 gpm), and the small hotwell reject valve was cycling excessively. Since that valve is downstream of the condensate pumps, the licensee believed that the feedwater control system responded to the repeated minor system fluctuations.

To address this problem, the licensee installed a blocking device in the small reject valve so that it would provide a continuous letdown from the condensate system to the CST. That constant flow would then require automatic operation of the hotwell makeup valve (CST water drawn into the hotwells) to maintain level. Operation of the makeup valve provided proper level control with less system impact because the makeup valves do not affect the condensate system downstream of the condensate pumps. The mechanical gag for the small hotwell reject valve was controlled via a temporary modification.

These activities were completed during this inspection, and resulted in a partial dampening of the power oscillations (from about 10 MW_t to about 5 MW_t). The licensee also linked the absence of flow through the water quality line to be the cause for minor problems associated with the condenser hotwell level controls. This problem was identified as an operator work-around (on the weekly Project Status Review Meeting summary), and has received significant management attention. The licensee then directed their efforts toward operation of the feedwater control system as well as the mechanical operation of the feedwater control valves (FCV). At the end of the inspection period, the small oscillations continued. The licensee was considering whether FCV packing or feedwater control system adjustments were appropriate.

The inspector reviewed the troubleshooting action plans for the small and large hotwell makeup valves and for the CRD water quality line. The temporary modification (96-106) for the mechanical gag on the small reject valve was also reviewed. These activities were well planned and conservatively conducted by the licensee.

c. Conclusions

Engineering personnel provided strong support in investigating the thermal power oscillations and associated balance of plant operational anomalies. Their efforts were successful in partially dampening the thermal power oscillations. Continuing evaluation activities were in progress at the end of this inspection.

E2.3 Containment Leakage in Excess of Technical Specification Limit

a. Inspection Scope (37551, 71707, 62707)

The inspector reviewed the licensee's identification of what appeared to be an excessive use of Nitrogen immediately following plant startup on October 22, 1996, and drywell inertion.

b. Observations and Findings

Following plant restart on October 22, 1996, following drywell inertion (8:30 p.m. October 23, 1996) and during power ascension, the licensee noted what appeared to be excessive Nitrogen (N2) makeup to containment (drywell and torus). During this period the licensee was not able to accurately determine the N2 makeup because plant power and drywell/torus temperatures were not fully stabilized. An additional factor was the location of the N2 flow sensing instrument had been changed during the 16R outage to reflect all N2 used in the drywell. The instrument prior to the outage recorded only the N2 used for drywell makeup. The new sensing point recorded all usage, including that used for valve and damper control. In addition, some N2 compressor casing leakage (identified during implementation of action plan 96-51) contributed to the indicated N2 used.

Plant operators almost immediately noted what they considered to be excessive N2 usage in the drywell. The shift technical advisors (STA) performed a gross leakage calculation on October 24, 1996, that indicated that leakage was above the Technical Specification limit. Engineering developed an action plan (96-51) to identify all sources of N2 leakage and to evaluate drywell N2 leakage. The licensee noted that accurate N2 usage could not be accurately determined until the plant power had stabilized for 10 hours. Full power was attained at 4:56 a.m. on October 25, 1996. The plant was manually scrammed at 11:59 a.m. on October 25, 1996, following a main turbine generator runback due to a stator cooling system problem.

Following the October 25, 1996, manual scram, the licensee implemented applicable portions of surveillance procedure 665.5.001, "Torus to Drywell Vacuum Relief Valve Leak Rate Test." The containment was pressurized to 2 psig. The licensee identified a cover plate on torus to drywell vacuum breaker valve V-26-5 as the source of leakage. The valve was subsequently disassembled and repaired. The reason for the leakage was determined to be a poor worker practice when surveillance procedure 604.1.005, "Torus to Drywell Vacuum Breaker, Mechanical Surveillance and Limit Switch Calibration" was performed during the 16R outage. The inner of two "O" rings was not seated in its groove and resulted in being pinched when the valve was reassembled. The valve did successfully pass a local leak rate test (LLRT) at the time. The procedure did not instruct the mechanic to check the cover plate to ensure that it was level when reassembled, although this activity was within normal worker skills and should not require specific instructions. As a result of this event, the licensee is revising the surveillance procedure to include specific checks to ensure the cover plate is level indicting the "O" rings are properly seated in their respective grooves. The licensee is also evaluating the method of LLRT to determine acceptability.

Subsequent to the repair, the licensee again pressurized the containment to verify that leakage was within the TS allowable value. The leakage rate calculated when the valve cover plate was leaking was 875 standard cubic feet per hour (SCFH). The TS allowed leakage was 426 SCFH. This event was reported via 10 CFR 50.72 and Licensee Event Report 96-11 (Section M8 of this report). Poor worker practice resulted in the primary containment leakage rate exceeding the TS allowable limit. This licensee-identified and corrected violation of technical specifications is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

c. Conclusions

The inspector concluded that poor mechanical maintenance worker practices resulted in the containment allowable leakage rate being exceeded. In this case the event was of minor safety significance because the standby gas system was operable and would have filtered any release and radioactivity levels were normal. Engineering provided strong support to operations in the implementation of an action plan to identify and correct the leakage. Operations was also alert in the identification of what appeared to be excessive N2 use in the drywell.

E7 Quality Assurance in Engineering (40500)

E7.1 Nuclear Safety Assessment Audit of Plant Support Engineering

The inspector reviewed Plant Support Engineering Audit Report S-OC-96-05 (June 19, 1996, Memorandum) that was conducted by Nuclear Safety Assessment. The results of the audit found that Plant Support Engineering provided effective support to the operations and maintenance functions. The audit report provided information to responsible personnel in a useful format, documenting noteworthy strengths, areas with identified deficiencies, and areas specifically requested by Engineering management as areas for inclusion in the audit scope.

The inspector noted that the licensee's Engineering organization made good use of audit resources by selecting areas for review, such as plant performance monitoring, plant modifications using 125-1 forms (engineering evaluation forms), effectiveness of communicating Engineering direction to Maintenance, and 10 CFR 50.59 reviews of 125-1 forms.

The audit did not identify any significant deficiencies, although it was noted that Engineering support on immediate problems was good, but not as good when required support was not urgent. The inspector concluded that the detail and quality of the audit was acceptable.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) Unresolved Item 50-219/93-03-01: This item concerned the need to clarify TS surveillance requirements and procedural acceptance criteria for the new (March 1993) A and B (B is safety related) station batteries. The new batteries were AT&T Lineage 2000 Round Cells. The old batteries were Gould FTA-21 type batteries. The licensee issued a licensing action item (LAI), No. 93037.01, to address NRC concerns that criteria for determining battery condition and operability may be different than the old battery. As a result, safety evaluation 735-004 was issued in June 1994. The safety evaluation recommended a TS change to revise the minimum voltage on the B battery to 2.09 volts from 2.00 volts. The increased minimum voltage criterion is more conservative than existing criterion. Procedure 632.2.002 and 632.2.003, the weekly and monthly surveillance tests for the station batteries, has been changed to reflect the more conservative value of 2.09 volts. On November 27, 1996, the licensee submitted a Technical Specification Change Request (No. 232) which implements the more conservative voltage value. This item is closed.

E8.2 (Closed) Licensee Event Report 96-09: Actuation of Engineered Safety Features (ESF) Caused by Loss of Power Due to a Cable Fault. This LER reported an event in which a reactor protection system actuation occurred and the reactor vent path isolated (with the reactor in refuel mode of operation) after electrical power was lost to the "D" 4160 volt safety-related bus. The bus was lost when a supply breaker tripped and locked-out due to a ground fault, subsequently determined to be on the power feed cables between the output breaker of emergency diesel generator 2 and 4160 volt bus "D." This event is discussed in detail in Section M1.5 of this report.

E8.3 (Closed) Licensee Event Report 96-10: Failure of Remote Shutdown Equipment to Operate Due to Contact Failure. This LER was submitted because an isolation condenser (IC) valve failed to operate as expected and as stated in the 10 CFR 50, Appendix R, Technical Data Report. Specifically, during a surveillance test on the RSP, IC condensate return valve (V-14-37) did not open from the RSP. The valve is designed to automatically re-open when the RSP is activated if it were to close during an Appendix R scenario.

The safety significance of this event as documented in the LER was considered to be minimal. In the postulated scenario, the electromatic relief valves and safety valves provide decay heat removal during the first ten minutes following the event. If the IC failed to actuate, the EMRVs and safety valves would continue to remove heat, and the control rod drive system would provide makeup as required as inventory would be lost. This failure would not have prevented achieving the desired and required results (achieving and maintaining Hot Shutdown for 72 hours).

Maintenance and engineering personnel subsequently determined that the cause for the valve failing to open was dirty contacts (oxide accumulation) on the control relay for V-14-37 in the RSP. The engineering staff was evaluating the measures to preclude the occurrence of dirty contacts, including 1) performing surveillances on the RSP more frequently to ensure continued operability, 2) developing methods to operate the relay contacts to ensure oxide layers are not formed; and 3) evaluating whether different contacts can be installed that are not susceptible to oxide formation.

This inspector determined that the licensee's response and followup of this event were acceptable. This LER is closed.

IV. PLANT SUPPORT

R1 Radiological Protection and Chemistry Controls

R1.1 General Observations (71707, 71750)

During entry to and exit from the radiologically controlled area (RCA), the inspectors verified that proper warning signs were posted, personnel entering were wearing proper dosimetry, personnel and materials leaving were properly monitored for radioactive contamination, and monitoring instruments were functional and in calibration. During periodic plant tours, the inspectors verified that posted extended Radiation Work Permits (RWPs) and survey status boards were current and accurate. They observed activities in the RCA and verified that personnel were complying with the requirements of applicable RWPs, and that workers were aware of the radiological conditions in the area.

R7 Quality Assurance in Radiological Protection and Chemistry

R7.1 Nuclear Safety Assessment Audit of Plant Chemistry (40500)

The inspector reviewed Plant Chemistry Audit Report S-OC-96-02 (June 13, 1996, Memorandum) that was conducted by Nuclear Safety Assessment. The results of the audit found that the Chemistry Program at Oyster Creek has been effectively implemented. No significant findings were identified. The audit did identify, however, that the Conduct of Chemistry Operations Procedure (106.6) requires that staff chemists conduct performance audits of selected department activities, as requested by the Manager, Plant Chemistry. There was no specific requirement regarding the type of audit that was required, nor was there a specified audit frequency; the last audit of that type was conducted by the Chemistry Department in March 1993.

Although audit S-OC-96-02 determined that there appeared to be an inconsistency with respect to the intent of the audit procedure and the Chemistry Department practices, no specific recommendation or action was taken in response to this finding. The licensee stated that Chemistry supervision constantly assesses department performance by routine technician performance and chemistry parameter monitoring, and by feedback by other individuals, such as the Chemistry Process Performance Team (CPPT).

The inspector discussed the audit finding with Chemistry management. The CPPT meets monthly to review chemistry performance. Procedure 106.6 is currently being reviewed for revision, and the licensee expects to credit CPPT performance as satisfying the audit requirement. The inspector concluded that the licensee's actions have been reasonable. The inspector determined that the NSA audit was of sufficient detail and quality.

S1 Conduct of Security and Safeguards Activities

S1.1 General Observations (71750)

During routine tours, access controls were verified in accordance with the Security Plan, security posts were properly manned, protected area gates were locked or guarded, and isolation zones were free of obstructions. Vital area access points were examined and verified that they were properly locked or guarded, and that access control was in accordance with the Security Plan.

V. MANAGEMENT MEETINGS

X1 Exit Meeting Summary

A verbal summary of preliminary findings was provided to the senior licensee management on December 26, 1996. During the inspection, licensee management was periodically notified verbally of the preliminary findings by the resident inspectors. No written inspection material was provided to the licensee during the inspection. No proprietary information is included in this report.

ATTACHMENT 1

PARTIAL LIST OF PERSONS CONTACTED

Licensee (in alphabetical order)

G. Busch, Manager, Regulatory Affairs
S. Levin, Director, Operations and Maintenance
K. Mulligan, Manager, Plant Operations
M. Roche, Director, Oyster Creek

NRC (in alphabetical order)

L. Briggs, Senior Resident Inspector
S. Pindale, Resident Inspector

ATTACHMENT 2

INSPECTION PROCEDURES USED

Procedure No.	Title
40500	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
37551	Onsite Engineering
61726	Surveillance Observation
62707	Maintenance Observation
71707	Plant Operations
71750	Plant Support
92700	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
92901	Followup - Operations
92902	Followup - Maintenance
92903	Followup - Engineering
92904	Followup - Plant Support
93702	Onsite Event Response

ATTACHMENT 3

ITEMS OPENED AND CLOSED

Opened

Number	Type	Description
50-219/96-11-01	VIO	Failure to conduct written safety evaluation per 10 CFR 50.59 for a procedure change that changed system operation as described in the UFSAR. (Section O1.4)

Closed

Number	Type	Description
50-219/93-03-01	URI	Clarification of battery characteristics in Technical Specifications. (Section E8.1)
50-219/96-08	LER	Manual Reactor Scram Due to a Main Generator Runback. (Section O8.1)
50-219/96-09	LER	Actuation of Engineered Safety Features Caused by Loss of Power Due to a Cable Fault. (Section E8.2))
50-219/96-10	LER	Failure of Remote Shutdown Equipment to Operate Due to Contact Failure. (Section E8.3))
50-219/96-11	LER	Primary Containment Leak Rate in Excess on Technical Specification Requirements Due to Incorrect Re-assembly of Valve Cover. (Section M8.1)