U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-440/96003

FACILITY

Perry Nuclear Power Plant, Unit 1

License No. NPF-58

LICENSEE

Cleveland Electric Illuminating Company
Post Office Box 5000
Cleveland, OH 44101

DATES

March 2 through April 19, 1996

INSPECTORS

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APPROVED BY

R. D. Lanksbury, Chief 5/31/96
Reactor Projects Branch 2 Date

AREAS INSPECTED

Routine inspections of operations, engineering, maintenance, and plant support were performed. Safety assessment and quality verification activities were routinely evaluated. Follow-up inspection was performed for non-routine events and for certain previously identified items.

RESULTS

This integrated inspection report covers aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 7-week period of resident inspection; in addition, it includes the announced inspections by a regional radiation specialist, an emergency preparedness specialist, and two projects inspectors.

Performance during the recently completed refueling outage was generally better than performance during the previous refueling outage. There was significant improvement in plant material condition and control of collective radiation dose. However, problems persisted with communications between organizations, control of contractors, configuration control, completeness of engineering work packages, and clarity of procedures. Personnel were generally sensitive to these problems as well as others, and continued to formally identify the problems for corrective actions. However, the inspectors continued to occasionally identify problems that had not been formally documented. Licensee management was continuing to aggressively pursue improvements in those areas. In some cases, such as with procedure improvement, the licensee had comprehensive improvement programs in place. While occasional personnel errors still occurred, past improvements in personnel performance were maintained.

OPERATIONS:

Improvement in operation's performance over the previous refueling outage was noted with some exceptions. Startup and operational activities were generally conducted in a controlled and cautious manner (Sections 1.0 and 1.6). The following exceptions were noted:

- A potentially serious error in the proper use of the personnel safety tagging system was appropriately addressed by licensee management (Section 1.3).

- Some weak sensitivity to maintaining reliable decay heat removal was highlighted with an unexpected interruption of cooling water to a heat exchanger (Section 1.1).

- Problems with procedures (Section 1.5) reinforced the need for timely completion of the ongoing major "Procedures Upgrade Program."

- The High Pressure Core Spray water leg pump was operated with its suction valve closed, indicating that there was room for improvement in control of equipment configuration (Section 1.4).

- Two examples of communications weaknesses demonstrated opportunities for improvement in that area (Section 1.8).

MAINTENANCE:

Maintenance activities were conducted well during the refueling outage with some exceptions (Section 2.0). The number and severity of material condition problems had been significantly reduced (Section 2.1). An appropriate questioning attitude identified a gasket partially blocking flow through a Residual Heat Removal pump orifice plate due to poor contractor workmanship (Section 2.2). The foreign material exclusion program was well implemented with some exceptions (Section 2.3). Workers identified some problems with parts resulting in rework in radiation areas (Section 2.5).

ENGINEERING:

Engineering activities observed were generally well performed. There was appropriate support of operations by the reactor engineers during startup activities (Section 1.6). Engineers appeared to be knowledgeable, experienced, and qualified. However, some engineers expressed a concern about their work load (Section 3.1) and some engineering work packages did not provide appropriate details (Section 3.2). The threshold for initiating Potential Issue Forms (PIFs) was low (Section 3.0). A degraded Emergency Service Water Pump resulted in an Unresolved Item (Section 3.3). The engineering response was appropriate to errors identified by General Electric (GE) in the analytical methods used in design and monitoring of the reactor core. However, the number of issues identified, combined with other GE performance issues indicated that the licensee's control of these contractor services was weak (Section 3.6). A situation related to effective corrective actions for Agastat relay replacement resulted in additional operator work arounds (Section 3.7).

PLANT SUPPORT:

Radiological controls for the fifth refueling outage were effectively implemented with significant improvement noted (Section 4.1.1). Inadvertent creation of a high dose area in the upper drywell indicated a program weakness with contractor performance which will be evaluated in the future (Section 4.2.1). The radiation protection and chemistry staffs' response in providing monitoring and assessment of the potential for an unmonitored release pathway from a leak in the heater bay was appropriate (Section 4.2.2).

Several emergency lighting units were identified as incorrectly positioned for safe egress or access to some emergency equipment (Section 4.4).

The overall operational status of the emergency preparedness program and response facilities was appropriate (Section 4.5).

SAFETY ASSESSMENT and QUALITY VERIFICATION:

The corrective action program has improved plant performance. There was an increased sensitivity to the significance of observed conditions. However, specific areas for improvement remained (Section 5.1).

During a Corrective Action Review Board (CARB) meeting, a larger than normal number of corrective actions were questioned and rejected. This reflected negatively on the PIF (corrective action) process leading to the CARB reviews (Section 5.2).

Enhanced QA activities were noted regarding field surveillances and overall observations of radiation worker practices indicating that the role of the QA organization in this area was effective (Section 5.4).

Summary of Open Items
Violations: Not identified in this report
Unresolved Item: Identified in Section 3.3
Inspector Follow-up Items: Identified in Sections 4.2.1 and 7(multiple)
Non-cited Violation: Not identified in this report

Report Details

Summary of Plant Status

The plant was in a scheduled refueling outage (RF05) that began on January 27 and ended April 10. Startup activities that were originally scheduled to begin on March 26 were delayed until April 4 because of a failed hydrogen seal on the main generator rotor shaft. On April 15, the operators reduced plant power to 10% and disconnected the generator from the grid to repair a feedwater leak on the motor driven feedwater pump. The generator was returned to service on April 16. Full power was achieved on April 17 and the plant remained at full power through the end of the inspection period.

1.0 OPERATIONS

Using Inspection Procedures 60710, 71707, 71500, 92720, and 92901 the inspectors conducted frequent reviews of ongoing plant operations. The inspectors noted considerable improvement in operation's performance over the previous refueling outage as demonstrated by outage activities being generally well coordinated, with maintenance activities presenting few challenges. Some exceptions are discussed below. The inspectors concluded that the operators conducted startup activities and other plant maneuvers in a controlled and cautious manner.

1.1 Sensitivity to Shutdown Safety and Decay Heat Removal Requirements

During the refueling outage, fire protection water temporary piping and hoses were used with a Nuclear Closed Cooling (NCC) heat exchanger to remove decay heat. Safety-related equipment was available as a backup. The inspectors routinely inspected decay heat removal equipment, observed plant management meetings, and periodically discussed shutdown safety with operators and maintenance personnel. The following observations were made:

- The importance and status of decay heat removal systems was regularly discussed at management meetings and shift turnovers.
- Operators were consistently aware of the decay heat load and status of decay heat systems, aided by status boards that were maintained with current information.
- Shutdown safety advisors periodically walked down the plant and regularly discussed shutdown safety at management meetings.
- Cables and hoses through open containment penetrations were controlled and monitored by designated personnel who were aware of their duties.
- Special shutdown safety signs were posted to advise workers of plant equipment important to shutdown safety. Work in posted areas was tightly controlled.

- Emergency diesel generators (EDGs) were included as required shutdown safety equipment (they were allowed to be excluded during some conditions in the previous refueling outage).

- Two valve problems during transfer of NCC heat exchanger cooling back to the service water (SW) system allowed a 6-minute interruption in the flow of fire protection water. This allowed NCC temperature to rise to 92# F. Reactor coolant temperature remained within the normal shutdown band of 95-105# F. Operators had attempted to divert the fire protection water from the discharge of the heat exchanger to fill the SW system. Engineering and outage management had proposed this new method for filling SW piping to shorten the outage. The operators closed an isolation valve (Hydrant 7) to stop fire protection water discharge flow back to the lake. A SW flow control valve was expected to open automatically. However, the valve did not open. This was promptly detected, but immediate manual efforts to open the valve were unsuccessful. There was a delay in opening Hydrant 7 to restore flow because the valve had frozen (outside temperature was 7# F). The licensee notified the inspectors and an inspector responded to the site to verify plant conditions and to observe the licensee's response to the unexpected flow interruption. Licensee management reviewed the activities with participation by all responsible parties. New instructions were drafted to attempt the evolution again. However, senior management decided to fill the SW system by the previously planned method. This event had minor potential safety consequences because decay heat load was low, the reactor cavity was flooded (large coolant inventory), backup cooling capability was available, and there was prompt and correct operator response.

- The inspectors observed a 4'x 6' work platform on the temporary fire protection water piping near the NCC heat exchanger. The piping had not been evaluated for use as a work platform support. This condition did not have any potential for damaging the piping, but such an installation could have led to conditions that challenged the integrity of the piping. The inspectors verified that the work platform was promptly supported by scaffold.

- During NCC heat exchanger work next to the heat exchanger in use for decay heat removal, workers dropped a heavy heat exchanger end bell (about 4 ft in diameter). The fire water temporary piping was only 4 feet away and could have been damaged if it had been struck by the end bell.

- A licensee employee identified that seal water leakoff from ESW pump 'B' was spraying on the operating fire protection water pump motor. This had been identified by the inspectors during the last refueling outage and a temporary spray shield had been installed. The shield had been removed during the operating cycle. The inspectors verified that a new shield was promptly installed.

- Licensee personnel identified that scaffolding had been erected near an EDG that was available to supply backup power for decay heat removal. The control room should have been notified prior to such work and that had not been done. The scaffold was not a threat to the EDG.

  The inspectors concluded licensee management had implemented a comprehensive plan for maintaining shutdown safety which included regular personnel emphasis and provided appropriate personnel to monitor implementation. The short interruption of temporary fire protection water was an isolated case involving two equipment failures that had not been specifically evaluated. Management review of the event was exhaustive and the resulting decisions were conservative. Other problems identified indicated that some personnel had not developed an appropriate sensitivity to the importance of decay heat removal equipment. However, in most cases, other licensee personnel with appropriate sensitivity formally identified the problems and management promptly developed effective corrective actions.

1.2 Refueling Issues

The inspectors observed refueling activities and concluded that they were well performed. The inspectors' observations of fuel movements and discussions with the refuel floor craft indicated that they used a cautious and deliberate approach to loading the core. The overall success of the refueling operations reflected a high degree of competence on the part of operations and the refueling personnel. The inspectors did note two minor instances that indicated that some opportunities still existed for improvement in refueling operations.

- When the 'C' Residual Heat Removal (RHR) injection isolation valve was opened, a large bubble rose in the Reactor Pressure Vessel (RPV) and disturbed the pool water enough to tip over a piece of equipment on the bottom of the refueling pool and detach and sink a pool surface viewing box. Although some air release was expected, the bubble was much larger than anticipated. The disturbance caused by the bubble forced suspension of refueling because of reduced visibility. The air release had minor potential safety consequence. The licensee documented the occurrence for corrective action investigation.

- An isolated occurrence involving a fuel bundle being inserted approximately 20 inches into the core misoriented by 90# was identified by the licensee. The inspectors determined that the licensee effectively identified and addressed the factors which contributed to the misorientation. No additional fuel misorientations occurred.

1.3 Control of Personnel Safety Tags

In the past the licensee had problems with control of its personnel safety tagging system and its other tagging systems for special activities such as MOV testing. During the refueling outage there were many tagging activities accomplished with various tagging systems. Only one potentially serious event was identified during this inspection period. A worker compounded a minor error by quickly closing a breaker that he had inadvertently opened. Although this self-reported event had no safety consequences, licensee management promptly recognized the serious nature of this type of reflexive response to a personnel error. The inspectors verified that the associated PIF was appropriately categorized and the avoidance of such improper action was stressed at the next outage meeting. The number of errors during this inspection period compared with the amount of work represented an improvement in performance. Generally licensee personnel remained sensitive to the proper use of tagging systems for personnel safety and equipment protection. Various personnel appropriately identified several less serious administrative tagging errors with Potential Issues Forms (PIFs - corrective action documents).

1.4 Equipment Configuration Control

Due to past problems with valves being out of position the Plant Manager had his staff perform additional valve lineups. Several out-of-position valves were identified during that effort. However, subsequent to this effort another out of position valve was identified due to a system problem. On March 19, after receiving a HPCS discharge pressure low alarm, operators shut down the HPCS water leg pump and performed a valve lineup. The water leg pump suction valve was found closed instead of open. There was no apparent damage to the pump. The licensee performed a Human Performance Enhancement System (HPES) evaluation of this error and found that the unit supervisor was not aware that a suction piping modification had been completed that required the valve to be closed. The unit supervisor had instructed the operators to fill and vent the system. However, fill and vent procedures were written for systems that have previously been lined up for normal operation. Therefore, performing the fill and vent did not identify the position of the pump suction valve. This event had no safety consequences because it occurred while HPCS was being prepared for return to service.

The inspectors concluded that the plant managers decision to perform additional valve lineups was an appropriate action to remedy past problems. However, the closed HPCS valve, identified by a plant alarm, was an indication that there was still room for improvement in control of equipment configuration. Information developed by the HPES would be sufficient to allow the licensee to develop appropriate corrective actions to ensure that on-shift management personnel maintained appropriate awareness of equipment configuration.

1.5 Procedure Weaknesses

During their routine review of plant events and activities the inspectors observed four cases where weaknesses in procedures challenged personnel performance. Similar situations had occurred in the past and the licensee had initiated a major long-term, site-wide "Procedure Upgrades Program" which was planned to be completed in 1998.

- On March 17, during restoration of the condensate system for startup, operators identified two events where valve lineups controlled by procedures had allowed more water to be transferred to the hotwell than intended. The inspectors questioned operators on control of plant water inventory and verified operator conclusions by reviewing condensate and feedwater drawings. In each case a complex, rarely performed procedure had directed the operators to rely on leaking valves to function as tight shutoff valves. During normal operations the valves, a control valve and a check valve, did not need to be tight shut off valves. Neither event had any potential safety consequences and in each case the operators responded promptly to their indications. After the second event the operators increased the frequency for checking hotwell level from two to six times a day.

- On April 4, operations personnel had begun a reactor pressure vessel pressure test and individual control rod scram time testing. The reactor was shut down at the time with temperature at about 138# F. System engineering personnel identified a weakness in temperature and pressure control in the procedures. The testing was immediately stopped to allow a thorough review of the specified test conditions. The system engineer was aware of a similar plant that had been doing the same tests and had inadvertently increased pressure beyond a technical specification low temperature pressure limit after an unexpected full scram. The test procedures were revised to require a higher temperature during the test. That increased the allowed operating pressure and minimized the possibility that a scram could increase pressure enough to exceed the technical specification pressure limit. Specific guidance was also provided to help the operators minimize any pressure increase if a scram occurred. The inspectors observed the licensee conduct a briefing for this infrequently performed test. Specific test termination criteria were emphasized. The inspectors verified that the operators were aware of the test termination criteria. The testing was completed without incident.

- On April 16, operators were preparing to shift the reactor recirculation pumps from slow to fast speed. During the first pump shift an instrument and control (I&C) technician had difficulty understanding the third note in Section 5.1 of System Operating Instruction SOI-B33, "Recirculation System." He received assistance from an operator and an I&C engineer in interpreting the note, which involved taking voltage readings from a panel in the control room. However, the pump shift was delayed because he had not used the correct terminal points. The error was corrected and both pumps were shifted without any additional problems.

For the hotwell level control events, the inspectors concluded that the volumes of water transferred were not significant because of plant conditions and because the operators had promptly identified the water transfers and corrected the situations. However, given that operations decided to maintain large volumes of water during the outage to minimize discharge and makeup, the review of the procedures to return the plant and the water volumes to normal should have been more effective. The inspectors concluded that conservative operating practices had been followed during the RPV and scram time testing and that there was appropriate engineering support of operations activities. However, more thorough preparation for the testing could have avoided the need to change the procedures after the test had begun. The inspectors concluded that the pump shift procedure was weak because three trained individuals working together did not accomplish it on the first attempt. The I&C technician promptly documented the problem in a PIF. These procedure problems reinforced the need for timely completion of the "Procedures Upgrade Program."

1.6 Operators Controlled the Plant Well During Startup

On April 7, the operators began pulling control rods as part of a normal startup from cold shutdown. The inspectors observed operators perform control rod pulls, reactor recirculation pump shifts to fast speed, and generator synchronization with the grid. The maneuvers were generally performed smoothly and were well controlled. The inspectors noted that the operators expressed the desire to "do it right the first time" which was a management phrase used to communicate to the operators that there was no undue pressure to get the plant on line quickly.

When the reactor was taken critical on April 7, 1996, the operations and nuclear engineering staffs observed that the source range nuclear instrument channels A and B indicated that the reactor was critical while channels C and D indicated that the reactor was subcritical. The reactor engineering staff recommended to the shift supervisor that control rods be inserted to take the reactor subcritical. The reactor engineers, using the same pattern, developed a plan where control rods were banked at smaller increments. The reactor was taken critical with the four source range instruments indicating criticality at the same time. The inspectors evaluated this evolution and concluded that the plant staff had demonstrated appropriate control and that there had been appropriate support of operations by the reactor engineers.

1.7 Motor Driven Feedwater Pump Leak

The inspectors observed diverse licensee activities related to control and repair of a feedwater leak and associated plant maneuvers.

On April 12, the operators completed a plant walkdown while at low power and identified a small leak on the motor driven feedwater pump (MFP) flow balancing pipe from a 3/4" pressure sensing line. The pressure sensing line was one of two used to measure flow through the 3" flow balance line between the discharge and suction of the pump. The licensee concluded that the leak could be repaired with a leak seal device. The inspectors observed the leak to be a small (about a 2 foot steam plume) leak typical of those sealed with leak seal devices.

On April 14, at about 10:30 p.m., an operator observed that the leak had grown larger. Efforts were still underway to procure a leak seal device. The licensee attempted to isolate the leak by closing the suction and discharge valves for the MFP because there were no isolation valves for the flow balance line. However, the suction valve leaked by and the leak continued to grow. Radiological aspects of the leak are discussed in Section 4.2.2. and a communications weakness is discussed in Section 1.8. On the morning of April 15 the inspectors observed licensee management meet to develop an action plan for the leak. The licensee considered appropriate facets of the problem and developed a conservative action plan. The inspectors observed that individuals at the meeting exhibited strong technical knowledge and questioning attitudes. The licensee decided to reduce plant power and take the main turbine off line in an effort to facilitate seating the MFP suction valve. At 12:34 p.m. the inspectors observed the operators manually trip the main turbine and maintain reactor power at about 14%. The evolution was well-controlled. The licensee then manually repositioned the suction valve and isolated the leak. The inspectors verified that the leak was successfully repaired using a temporary modification to replace both pressure sensing lines with pipe plugs. The licensee synchronized the generator with the grid at 1:47 a.m. on April 16. Because the licensee had to repair the motor operator for the MFP suction valve and remove water from the MFP lube oil system, the MFP was still out of service at the end of the inspection period.

The inspectors concluded that the licensee used conservative decision making and an appropriate technical methodology in sealing this leak. The licensee also applied appropriate resources to the restoration of the MFP due to its probabilistic risk analysis importance.

1.8 Communications Weaknesses

Communications between organizations at Perry has been a problem in the past. The inspectors evaluated communications and personnel sensitivity to improving communications during all observed activities. The inspectors concluded that the licensee's efforts had improved communications and increased individual sensitivity to identification of communications weaknesses. Although the inspectors did not identify any communications weaknesses, licensee personnel documented with PIFs two communications weaknesses.

- On April 15, as a feedwater leak (Sections 1.7 and 4.2.2) grew larger, the plant environmentalist and health physicist were not promptly notified. That reduced the plant's effectiveness in responding to the radiological aspects of the leak.

- With the Unit 1 Startup (SU) Transformer off site for repairs, the importance of the Unit 2 SU Transformer had increased. The inspectors verified that the licensee was protecting the Unit 2 SU Transformer with added precautions, including control room notification of work that could impact availability of the Unit 2 SU Transformer. On April 19, personnel working near the cables for the Unit 2 SU Transformer had not notified the control room.

2.0 MAINTENANCE AND SURVEILLANCE

The inspectors used NRC Inspection Procedures 62703, 61726, and 92902 to perform inspections of maintenance and testing activities during the refueling outage and startup. Maintenance activities during the outage were generally completed in a professional manner with some exceptions. Work packages were present, the craft were knowledgeable of the work they were performing and had a questioning attitude; supervision was normally present; and outage management was actively engaged in control and responsive to identified problems.

2.1 Material Condition

The refueling outage included **modifications** of the main turbine, Reactor Feedwater Pump 'A,' the reactor core isolation cooling turbine exhaust valve to the suppression pool, the leak detection system instrumentation, the plant process computer, the recirculation pump seals, and the emergency closed cooling temperature control valves; **installation** of an alternate boron injection pump; **replacement** of all RPV safety relief valves (shortly after plant startup one of 19 was weeping to the suppression pool, two were weeping during the previous operating cycle); **rebuilding** of 25 control rod drive mechanisms; **completion** of Generic Letter 89-10 MOV testing; **inspection and repairs** of underground service water piping and emergency diesel generators; and fuel sipping.

During the refueling outage, the number of Temporary Modifications (TM) was reduced from 20 to 1, a leak seal device on a balance of plant steam line drain. Four leak seal devices were added during startup.

Offgas system discharge volume was reduced to about 16 standard cubic feet per minute with the plant at full power. This was the lowest volume that had ever been observed and indicated that the amount of air leaking into the condenser and parts of the condensate system was lower than it had been in the past.

Startup was delayed approximately 10 days due to rework of a main generator hydrogen seal that had been incorrectly modified by GE. Once startup began, there were no material condition problems that required shutting down the reactor. Based on the inspectors' knowledge of previous plant refueling outage startups, the number and severity of problems had been significantly reduced. However, there were mostly minor material condition problems identified during licensee and inspector walkdowns (exceptions were the motor driven feedwater pump leak discussed in Section 1.7 and the feedwater heater leak discussed below).

- A leak from a threaded pipe plug on a reactor main feedwater bypass line identified by the inspectors was promptly sealed.

- A leak from a discharge check valve flange on Reactor Feedwater Booster Pump 'A' was identified by the licensee. The inspectors talked with the system engineer, noting that significant work had been performed during the outage to repair the leak and remove a leak seal device. The system engineer related that multiple efforts had been made to repair the flange and he did not know what more could be done.

- A leak on a drain line to the direct contact heater flange connection was identified by the licensee. The inspectors observed the leak with a licensee camera. The leak was a low energy (approximately 14 psig) leak which was sealed with a leak seal device.

- A leak from an access opening on the crossunder line between the main steam reheaters identified by the licensee was sealed with leak sealant.

- The two reactor vent valves (in series) were weeping to the identified leakage sump in the drywell contributing to a total leakage of about 1.75 gpm. Typical total leakage to the sump during the last cycle was about 2.0 gpm.

- A tube leak on Feedwater Heater 6A resulted in a loss of about 2500 gpm back to Feedwater Heater 4. This leak later forced the operators to monitor a condensate demineralizer bypass valve that was opening on high differential pressure. This also complicated control rod withdrawal because of the lower feedwater temperature. This leak was still active at the end of the inspection period.

- Degraded performance of the Emergency Service Water A pump (Section 3.3) for long term operability.

2.2 Appropriate Questioning Attitude During Post Maintenance Testing

On March 10, an operator identified, during post maintenance testing, that a residual heat removal pump was operating at 300 gpm less than normal (but greater than 7100 gpm as stated in the UFSAR). His conclusion was based on experience, as the flow rate met the surveillance test requirements. Investigation by the licensee found that an orifice plate gasket in the test return line to the suppression pool was incorrectly cut with one of the six orifice plate holes covered by the gasket material. The licensee installed a new gasket. The inspectors concluded that the operator demonstrated an appropriate questioning attitude, the failure to properly cut the gasket was the result of poor workmanship on the part of contract maintenance personnel, and that outage engineering management responded aggressively to the operator concern.

2.3 Foreign Material Exclusion

The inspectors observed numerous examples of effective actions by plant maintenance personnel to exclude foreign material from equipment. Based on these observations the inspectors concluded that, with minor exceptions, the foreign material exclusion program was well implemented. Exceptions identified by the licensee are listed below.

- Several items were dropped in the reactor Pressure vessel during refueling activities: the head of a ball lock pin (1" x 1/2" cast steel), a clamp from initial reactor startup vibration monitoring equipment that was being removed; an adjusting collar on a slide hammer; and a rope and viewing box that sank (Section 1.2). All items listed were recovered from the vessel.

- A piece of tape was found over a recirculation pump seal line; apparently it had been put there to exclude foreign material during work in the previous refueling outage. The inspectors questioned the responsible system engineering (RSE) who stated that the tape had not significantly affected seal water flow. The inspectors had regularly observed seal flow indications during the operating cycle and agreed with the RSE's conclusion.

- An air inlet line for a main steam isolation valve was found uncovered. No foreign material was found inside.

2.4 Surveillances

The inspectors observed all or portions of the following complex and infrequent surveillances performed during the refueling outage. All equipment performed as expected and presented no challenges to the operators. The inspectors concluded that the operators demonstrated a thorough knowledge of the surveillances and noted that plant management provided additional oversight during the surveillances and that operations conducted comprehensive "infrequently performed test or evolution" briefings.

- Surveillance Instruction (SVI) R43-T5367, Rev. 6, "Low Pressure Coolant Injection (LPCI) B/LPCI C Initiation and Loss of EH12 Response Time Test." The surveillance simulated a Loss of Offsite Power with a concurrent Loss of Coolant Accident.

- SVI-R43-T1330, Rev. 3, "Simultaneous Start of All Diesel Generator" March 23 and 24. This surveillance is required every 10 years.

2.5 Warehouse Parts Support

Several licensee workers appropriately identified various problems with parts that had caused inefficient use of maintenance resources, including rework in radiation areas. The inspectors reviewed the licensee-identified problems documented during the inspection period and identified that there appeared to be repetitive problems with warehouse (materials management) support of the plant. Later, on April 19, 1996, the licensee initiated PIF 96-1942 related to an overview of 1995 materials management PIFs. The overview, completed in early April, had identified several issues requiring additional action or evaluation. This PIF combined with a QA audit that began near the end of the inspection period should provide sufficient information to allow the licensee to develop appropriate corrective actions.

2.6 Work Planning

The inspectors observed significant improvement in planning for refueling outage work. In addition, licensee personnel continued to appropriately identify planning problems that had reduced work efficiency. This indicated that the licensee's continued efforts to improve implementation of the planning process were appropriate.

3.0 ENGINEERING

NRC Inspection Procedures (IP) 37550, 37551, 40500, and 92903 were used to perform onsite inspections of the engineering function. The inspectors considered that the engineering activities observed were generally well performed. The inspectors noted that the threshold for initiating Potential Issue Forms (PIFs) was low and the number of PIFs issued during the last year had considerably increased from previous years. However, several weaknesses were identified, including minor weaknesses in the modification process, weaknesses in the over sight of contractor services, and some weaknesses in the corrective actions for Agastat relay problems.

3.1 System Engineering

The inspector interviewed several system engineers. The engineers appeared to be knowledgeable and qualified for the jobs assigned. Some engineers expressed a concern that they were overburdened with too many systems and were not able to meet all expectations of the System Engineering Handbook. This had also been identified in an earlier licensee self assessment of Engineering & Technical Support (E&TS). The inspectors verified that the licensee had developed corrective action plans for the issues identified during the self assessment.

3.2 Design Engineering Details Not Being Provided

The design engineers interviewed were experienced and knowledgeable in the areas assigned. However, appropriate details were not being provided in some design change packages (DCPs) as identified in PIF 96-0811. This PIF indicated that the DCP did not provide details or test instructions to verify switch contacts for a flow control valve. Lack of details in DCPs was also identified in an earlier licensee self assessment of E&TS. The inspectors verified that the licensee had developed corrective action plans for the issues identified during the self assessment.

The inspectors reviewed design change DCP 95-009, "Change of Five ESW Safety Relief Valves to a Different Design," in progress. The design package included an appropriate description of the change, necessary technical reviews and approvals, and a suitable 10 CFR 50.59 review.

PIF 96-1257 on DCP 94-0027A indicated that the 'A' Emergency Closed Cooling (ECC) Temperature Control Valve modification was identified by the licensee during implementation as not being thorough. The DCP did not specify electrical conduit runs, RTD element installation, and switch configurations. A number of less significant problems were identified and corrected by field clarification requests or simple modification requests. The licensee identified the weaknesses in this DCP and attributed them to insufficient review and understanding of CEI drawings and documentation, incomplete field walkdowns by the design consultant, and insufficient reviews of the work by CEI personnel.

The inspectors concluded that, although the licensee had improved the quality and timeliness of design engineering for modifications, there were still weaknesses remaining in final implementation of the modification process. The inspectors verified that the licensee was developing long term corrective actions.

3.3 Degradation of Emergency Service Water (ESW) Pump 'A'

At the end of RFO5, testing of ESW Pump 'A' revealed that minimum design flow through the Division I Emergency Diesel Generator Heat Exchanger (highest elevation heat exchanger) with the ESW outlet valve full open could only be achieved by throttling other Division I ESW heat exchanger flows (lower elevations). ESW Pump 'B' had been rebuilt with a modified impeller design and was performing better than ESW Pump 'A.' The work order to rebuild ESW Pump 'A' had been voided. Engineering initiated a new work order to perform the rebuild in the next refueling outage. Engineering concluded that ESW Pump 'A' was capable of providing all Division I heat exchangers with at least minimum design flows with some margin available for additional throttling should ESW Pump 'A' degrade further. The inspector's initial review of the licensee's evaluation revealed some uncertainties which the licensee could not immediately resolve. Review by the inspectors of the licensee's basis for concluding that ESW Pump 'A' will remain operable through operating cycle six is an Unresolved Item (50-440/96003-01).

3.4 ABB Electrical Circuit Breakers

The inspectors noted that refurbishment and replacement of all safety-related 4.1KV and 480 Volt ABB breakers was scheduled to be completed during the current refueling outage per the licensee's earlier commitment. The inspectors verified that the licensee was making satisfactory progress in meeting its commitments on completion of all breaker refurbishment.

3.5 Reactor Engineering and Fuel Design

The fuel manufacturer, General Electric (GE), identified several issues related to errors in analytical methods used in designing and monitoring the reactor core. The inspectors evaluated engineering response to these issues and concluded that appropriate actions were promptly taken to insure conservative operation of the reactor. See Section 7.12 for details. However, the number of issues identified, combined with earlier GE fuel issues, indicated that the licensee's control of these contractor services was weak.

3.6 Weak Corrective Actions For Agastat Relay Problems

Prior to the refueling outage, licensee personnel identified an inappropriate extension of the periodic replacement dates for hundreds of Agastat relays. Appropriate management attention was promptly focused on prioritized remedial actions. However, by the time this error was identified it was too late to allow replacement, prior to the end of RFO5, of 234 relays that had exceeded their projected service lives. As a result, at the end of the inspection period, additional periodic operator action (a work around) was required to verify continued operability of the relays. The work around required the operators to periodically perform additional walkdowns of plant equipment. The licensee had expended significant effort to correct similar Agastat relay problems about 3 years earlier. Therefore, this situation showed that the licensee has not uniformly developed its ability to establish lasting corrective actions.

4.0 PLANT SUPPORT

NRC Inspection Procedures 71750, 82701, 83750, 92904, and TI 2515/131 were used to perform an inspection of Plant Support Activities.

4.1 Radiological Controls

4.1.1 Refueling Outage Radiological Controls

The inspectors reviewed the licensee's radiological controls program implemented for the fifth refueling outage (RFO5). This review included observations of work in progress, general plant tours, reviews of as-low-as-reasonably-achievable (ALARA) job packages, and interviews of various individuals within the radiation protection and other station departments. Several selected higher exposure jobs were monitored both remotely and onsite throughout the RFO.

The station had recorded about 302 person-rem (p-rem) based on secondary dosimetry results for the outage. This total was very close to the station established goal of 300 p-rem for the outage. The goal appeared to be reasonably aggressive based on the work scope planned for the outage. The actual dose measured by thermoluminescent dosimetry was expected to be less than 300 p-rem, based on the calibration of the secondary dosimetry. Exposures recorded for major work activities during the outage were as follows:

Bio-shield Annulus Work	57.4 p-rem
Scaffolding	33.6 p-rem
Vessel Disassembly/Assembly	26.4 p-rem
Under-Vessel Work	26.8 p-rem
Health Physics General Coverage	17.9 p-rem

The main contributors to this improved performance were the licensee's extensive outage job planning prior to the outage and the effective chemical decontamination of the fuel pool cooling, reactor water cleanup, and reactor recirculation systems. Heightened radiation worker awareness to personnel exposures and closely monitored job performance by the ALARA staff were also noted.

The radiological controls program for the fifth refueling outage was effectively implemented with significant improvement noted relative to previous outages. Notable areas of improvement included lower collective outage dose, work control and scheduling, and source term elimination through chemical decontaminations.

4.2 Miscellaneous Radiological Controls

4.2.1 Inadvertent High Dose Rates Created in the Drywell Due to Vibration Monitoring Instrumentation Removal (VMIR) Activities

The inspectors reviewed one issue involving the placement of highly irradiated components in the reactor cavity in such a fashion that high dose rates were inadvertently created in a localized area in the upper drywell.

The station was in the process of removing vibration monitoring instrumentation and associated cabling from the reactor vessel. The components were all highly irradiated and were stored underwater in corners of the cavity floor. During the performance of a routine survey, a health physics technician noted that some of the cabling was extending over the reactor cavity bellows area. This area did not have the benefit of the thick concrete cavity floor to aid in shielding lower elevations. Underwater dose rate measurements of the cabling detected a hot spot of 500 rem/hr in a localized area. The technician noted that the cabling in the bellows area could affect dose rates in the upper drywell areas located below the bellows. The drywell control point was subsequently notified of the condition and surveys were performed of the upper drywell. The drywell surveys noted that a 20 rem/hr contact, 2 rem/hr at 30 cm, localized hot spot had developed above the "C" main steam line. The licensee initially established the required controls for a locked high radiation area but later removed the postings and controls once the area was determined to be inaccessible.

The licensee immediately verified via recorded electronic dosimeter data that no workers had entered the high dose rate area. Shortly after the discovery of the cabling extending over the bellows area, fuel handlers moved the cabling to its appropriate storage area on the cavity floor. The licensee initiated a Category 2 PIF which required a root cause evaluation of the event. At the conclusion of the inspection, the licensee's investigation was still in progress.

The inspectors reviewed this incident and noted programmatic weaknesses which contributed to this event. The first item noted was that the VMIR job was not given the same level of heightened awareness as other incore/invessel component removal activities (e.g., traversing incore probes, low power range monitors). This led to the ALARA review for the job not including special precautions for handling the irradiated material to ensure that it did not affect radiological conditions within the upper drywell area (via the bellows). A contributing factor was the licensee's manner of reviewing industry generic events and NRC Information Notices (INs). Several INs have been issued regarding exposure hazards associated with invessel components and the possible changes in radiological conditions within the drywell which could occur during the movement of such components. The inspectors reviewed the plant's evaluation of INs 88-63, 88-63 Supplement 1, 88-63 Supplement 2, and 95-56. The inspectors noted that although the review of the INs appropriately addressed the specific issues discussed, the reviews were limited in focus and did not consider a broader application to other work activities outside the specific event or system presented.

The inspectors will review the results and effectiveness of the licensee's investigation and corrective actions taken in response to this event during a future inspection. No violations of NRC requirements were identified; however, this will be tracked as an Inspection Follow-up Item (IFI)(50-440/96003-02).

4.2.2 Response to Motor Driven Feedwater Pump Leak

On April 14 the amount of steam leaking from motor driven feedwater pump piping increased (Section 1.7). The leak grew large enough to have an impact outside the heater bay (an unmonitored release pathway). The inspectors discussed the radiological conditions with licensee personnel and inspected the area outside the building on the morning of April 15. Contaminated water condensed from steam had collected on the roof of the underground heater bay stairwell. The roof was slightly above ground level. A graveled area (about 0.2 square meters) adjacent to the roof was wet where water had flowed from the roof. The licensee obtained dirt and gravel samples at that location and identified low levels of contamination (about 3,000 disintegrations per minute). Later the licensee removed the affected dirt and gravel. The licensee used sandbags, absorbants, and plastic sheets to contain the water on the roof. Near one set of the building's closed ventilation louvers, the inspectors observed occasional wisps of water vapor and asked the licensee if an unmonitored release pathway existed. The licensee stated that air samples taken at the louvered area and at other nearby locations indicated no measurable activity; thus an unmonitored release pathway did not exist. Inside the heater bay the inspectors verified that the licensee had placed plastic sheets between the leak and the outside wall to minimize transfer of contaminated water through small openings in the wall. The licensee later vacuumed up the water and covered the affected area with plastic sheets to prevent expected rainfall from spreading any residual contamination. The inspectors verified that the plastic sheets were secure after the rainfall began. The licensee later completed cleaning of contaminated areas and completed surveys that showed no remaining contamination.

Overall, the inspectors determined that the radiation protection and chemistry staffs' response to the leak in providing monitoring and assessment of the potential for an unmonitored release pathway was good.

4.3 Security

On March 9, 1996, the licensee determined that on March 8, an individual had acted in an aberrant manner to news of his planned layoff. The licensee identified a delay in the reporting of this situation to security personnel. The inspectors discussed this with Region III security inspectors who reviewed the situation with licensee security personnel and determined that they would evaluate it in a future inspection as an Inspection Follow-up Item (IFI)(50-440/96003-03).

4.4 Fire Protection - Emergency Lighting

The inspectors checked the positions of several emergency lighting units to verify that they could perform the functions described in the UFSAR. An emergency light that could not illuminate its target equipment had been identified in the previous inspection period. Some of the inspected lighting units were incorrectly positioned to provide maximum illumination for target areas.

The inspectors also observed some minor UFSAR editorial errors and notified the licensee of all the inspection findings (Section 7.17). Since this inspection was conducted on the last day of the inspection period the licensee had not developed any corrective actions by the end of the inspection period. Reduced emergency illumination could reduce operator effectiveness in responding to an emergency if power were lost to normal lighting systems.

4.5 Emergency Response Facilities and Organization

Inspections were conducted in the Control Room, Technical Support Center (TSC), Operations Support Center (OSC), and Emergency Operations Facility (EOF). Material condition of facilities and equipment was excellent. The inspectors verified that equipment and instruments were operational in the facilities and selected procedures were current and available.

The inspectors questioned the suitability of the Training Building's (EOF) normal ventilation system because one of the two supply fans was out of service. The inspectors discussed and reviewed procedures and diagrams for the EOF's emergency ventilation system with the responsible engineers. The inspectors concluded that having only one supply fan operating would not adversely affect EOF emergency ventilation operation.

The inspectors interviewed the EP and training staffs to identify any changes to the organization, management, or program, and impact to the effectiveness of the program. The inspectors identified no concerns.

4.5.1 Review of Actual Emergency Plan Activations

The inspectors reviewed the records associated with two Unusual Events that had been declared since the last EP inspection. The operational aspects of these events had been reviewed by inspectors on site when they occurred on December 30, 1994, and February 5, 1995. The inspectors confirmed that classifications and notifications had been made properly and in a timely manner. Documentation packages for each event were detailed and complete.

4.5.2 Training

The inspectors reviewed selected EP training lesson plans and found them to be appropriately updated. Records indicated that training, drills, and exercises had been formally critiqued. The inspector reviewed the January 17, 1996, revision of the Site Training and Requirements Tracking System printout, Revision 96-1 of the Perry Emergency Telephone Directory, and random documentation reviews. These documents showed that all reviewed emergency response organization (ERO) personnel were currently qualified.

The inspectors interviewed key ERO personnel and included an Emergency Coordinator, TSC Operations Manager, CR/TSC Communicator, and a Shift Supervisor. Personnel interviewed responded well to questions regarding their emergency responsibilities and were familiar with emergency actions and procedures.

4.6 TI 2515/131, Licensee Offsite Communications Capabilities

As required by the TI, the inspectors verified that communications systems available to notify offsite agencies in the event of natural disasters included:

1. "5 Way Phone," the primary, dedicated ring down line, was located in the CR, TSC, EOF, and State emergency operations center (EOC).
2. Commercial phone lines were available in the CR, TSC, EOF, Backup EOF, and State EOC.
3. Private Branch Exchange (PBX), the site fiber optics phone system, was located in the CR, TSC, and EOF.

4. Corporate offsite private exchange (OPX), which provided a microwave link between corporate offices and the plant, was located in the CR, TSC, OSC, and EOF.
5. Secondary Alarm Station Radio was available to the Lake County Sheriff's Department (local county EOC).

The 5 Way Phone, commercial lines, and the PBX used fiber optics to connect to Alltel Company. These three systems passed through a common distribution cabinet in the Phone Room, on the second floor of the Service Building. The Service Building was not a Class I structure and was susceptible to severe earthquakes and tornados. The Phone Room used key entry and had a Halon fire suppression system. The fiber optics lines offsite were above ground and susceptible to ice and high winds. The power supply for these three lines was plant uninterruptible power source (UPS) backed up by a battery.

The OPX used a microwave transmission tower and was powered by Bus H-11 and backup battery power. Spare parts including cabling, antenna parts, and switches were stocked. Contingency communications procedure, PSI-0007, Revision 2, dated February 17, 1995, was available and in place. The foregoing fulfilled the requirements of the TI and the TI is closed.

5.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION (SAQV)

NRC Inspection Procedures 40500, 92720, 92901, 92902, 92903, and 92904 were used to perform an inspection of Safety Assessment and Quality Verification activities. No violations or deficiencies were identified.

5.1 Effectiveness of Corrective Actions

Licensee personnel use a Potential Issue Form (PIF) to formally document issues or conditions which may need to be corrected. The licensee's threshold for initiation of a PIF was that an observed issue or condition did not meet the observer's expectations. The inspectors reviewed about 820 current PIFs. During the same period in the previous year the inspectors reviewed about 380 then-current PIFs. The larger number of PIFs written during this inspection period were generally of the same significance as the PIFs written during the same period in the previous year. The increase appeared to be a result of the increase in personnel and activities during the refueling outage (RFO5) and greater sensitivity to conditions that may have gone unreported in the past. PIFs written as a result of PIF trend analysis also continued to demonstrate that the licensee was more sensitive to the potential for less significant precursor events to allow identification of corrective actions in an activity before a significant condition developed. The inspectors observed that PIFs continued to reflect appropriate sensitivity to the importance of identifying issues by a wide cross section of licensee staff. However, the inspectors identified two cases where conditions had not been promptly documented with PIFs; one involved material missing from an emergency operating procedure tool box and the other involved damaged NUKON insulation in the drywell. In both cases appropriate corrective actions were initiated.

The inspectors concluded that corrective actions have improved plant performance. This was demonstrated by the improved material condition of the plant and the improvements in work implementation during RFO5. However, specific areas for improvement remain and the licensee continued to identify weaknesses in their own performance. For example, there were continuing problems with control of measuring and test equipment. The licensee also identified several minor errors in safety tagging and a weakness in the immediate response of an individual to a tagging error. A thorough corrective action audit also identified several opportunities for improvements.

5.2 Corrective Action Review Board

The inspectors attended a Corrective Action Review Board (CARB) meeting. The licensee conducts about two meetings per week lasting 4 to 6 hours each to review corrective actions for PIF closure. The inspector noted that each required department in the organization was represented; questions were insightful with considerable debate; a significant number of corrective actions were questioned; and about half of the PIFs were rejected. The licensee uses the rejection rate as a performance indicator and the monthly rejection rates had been lower than what the inspectors observed at the meeting. Although the observed meeting indicated appropriate conservatism in reviewing corrective actions, the rejections indicated that preparation of some of the PIF corrective actions had not been thorough enough.

5.3 Plant Operations Review Committee (PORC) Meeting

On April 17, 1996, the inspectors observed a PORC meeting called to discuss an error in GE's methodology for calculating the minimum critical power ratio (MCPR) safety limit. The meeting was held after GE discussed the issue with the NRC at NRC headquarters earlier that day. Before the GE meeting the licensee had provided instructions to the operators to limit the indicated maximum fraction of limiting critical power ratio (MFLCPR) to .985 instead of 1. During the meeting the licensee evaluated reducing the MFLCPR limit to .98. The limit was reduced. The inspectors observed that the meeting participants demonstrated strong questioning attitudes, were open to discussion of all relevant issues, and explored appropriate aspects of the change.

5.4 Formal Self Assessments

The inspectors reviewed several QA surveillances and audits, and a maintenance rule implementation self assessment. The surveillances provided prompt insights into field activities. The corrective action audit included thorough and detailed findings which provided the licensee with numerous opportunities to improve its corrective action program implementation.

The 1995 and 1994 annual audits of the EP program were reviewed and found to be of excellent scope and depth, satisfying the requirements of 10 CFR 50.54(t). The audits found strong performance in the EP program and the state and local interface. The Potential Issues Form (PIF) system was used to identify, track, and close issues identified. The inspectors verified that the section of the audits dealing with the adequacy of the offsite interface had been provided to offsite authorities as required.

Enhanced QA activities were noted regarding field surveillances of work in progress and overall observations of radiation worker practices. Several PIFs were generated as a result of QA observations and responsible organizations were responsive to the findings. The QA organization was compiling a database of observations from RF05 to use for trend analysis and lessons learned for future outage activities. Overall, the inspectors determined that the role of the QA organization to monitor radiological control activities and highlight programmatic problems was effective.

The maintenance rule implementation self assessment used experienced outside participants to provide detailed guidance for improvements in the licensee's maintenance rule program.

The inspectors also reviewed PIFs that had been written during performance of a materials management audit that was still in progress. The PIFs indicated that the audit was aggressively evaluating materials management activities.

The inspectors concluded that various formal self assessment techniques were being used effectively to identify areas for improvement across a wide spectrum of plant activities.

6.0 LICENSEE ACTION ON PREVIOUSLY IDENTIFIED ITEMS

NRC Inspection Procedures 92700, 92701, 92702, 92901, 92902, 92903 and 92904 were used to perform follow-up inspection of the items below.

6.1 Action on Licensee Event Reports (LER)

(Closed) LER 50-440/93-13-00: Failure of Control Room Ventilation Supply Fan Motor. This LER was issued due to non-availability of both trains of control room HVAC for emergency recirculation mode as required by Technical Specifications. While train B of the system was in maintenance, train A tripped on fan motor overcurrent. The manufacturer of the motor (Reliance Electric) stated that the failure could have been due to a power system voltage surge. The licensee monitored the system for several months, but could not identify any voltage surge problems. The inspectors periodically verified the operation of the monitoring equipment. The motor manufacturer also ruled out any potential manufacturing (material or process) problems as no other similar failures were reported. The licensee did not experience any further similar motor failures and considered this to be a random failure.

(Closed) LER 50-440/96-001-00: Control Room Emergency Recirculation System Technical Specification Time Limit Exceeded. On February 9, 1996, at 11:45 a.m., the plant was in a refueling outage with core alterations in progress. One train of the Control Room Emergency Recirculation system had been inoperable for 7 days. Operations personnel failed at the end of 7 days to place the operable train in the Emergency Recirculation mode of operation as required by Technical Specification 3.7.2, Action b.1. A non-cited violation was identified for this event in Inspection Report 96002.

(Closed) LER 50-440/96-002-00: Inverter Failure Results in Partial High Pressure Core Spray System (HPCS) Initiation. On February 18, 1996, at 2:30 a.m., during refueling outage maintenance activities in Operational Condition 5, a Topaz inverter failure caused an unplanned partial automatic actuation of the HPCS system and the associated Emergency Service Water system. The HPCS system had been partially taken out of service and no injection into the reactor pressure vessel occurred. The event was caused by an intermittent failure of a degraded capacitor in the inverter circuitry. Corrective actions included a review of preventive maintenance tasks for associated Topaz inverters to ensure inclusion of inspection or replacement of appropriate components such as capacitors.

6.2 Review of Previously Opened Items (Violations, Unresolved Items, Inspection Followup Items)

(Closed) Unresolved Item (50-440/93011-04(DRP)): This item concerned weaknesses in the licensee's post-maintenance restoration practices. Specifically, it appeared that the licensee's work procedures were either inadequate in controlling system configuration to ensure that systems were properly restored or the procedures in place were not being followed. During the previous operating cycle, the licensee implemented a "Temporary Condition/Restoration" checklist for work packages and improved the planning of the work packages. During the operating cycle and the recent refueling cycle there were no significant failures to properly restore systems to operation after maintenance.

(Closed) Violation 50-440/94006-01A/B(DRSS): During the 1994 routine EP inspection it was identified that a 1993 exercise weakness concerning respiratory protection had not been corrected. Also, formal critiques had not been provided after all EP training as required. The inspectors verified that the Commitment Tracking Program, PAP-0610, had been revised to ensure commitments, including weaknesses, were entered into the Perry Regulatory Information Management System. The inspectors reviewed changes to the respiratory qualification tracking system and records to verify that appropriate corrective actions had been taken. Also, the inspectors verified that the Emergency Plan Training Program, TMP-2302, had been revised to require course critiques. The inspectors' Review of training critiques and feedback records indicated the corrective actions taken had been appropriate.

7.0 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 following applicable portions of the UFSAR that related to the areas inspected. The following inconsistencies were noted between wording of the UFSAR and the plant practices, procedures, and parameters observed by the inspectors.

7.1 UFSAR FIGURE 5.4-16, REACTOR WATER CLEANUP SYSTEM

This figure did not show five 3/4" instrument line high point vent valves that had been installed as part of the original design of the system. Licensee personnel identified that the valves were not shown on the figure and on March 27, 1996, initiated Design Change Notice (DCN) No. 5375 to add the valves to the figure.

The inspectors reviewed the DCN and safety evaluation (SE). The DCN SE did not include valve 1G33F0552 in the written description of the item to be evaluated, although a marked-up drawing was included which showed the addition of this valve. The valves were normally closed manual vent valves and their normal function was to maintain the pressure boundary. Therefore, omission of one valve from the written description was not significant. Adding the valves to the design as reviewed by the NRC would have only a negligible impact on increasing the probability of a leak in the system. It would be difficult to qualitatively assess this increase, however it was clear that adding components, unless they were perfectly reliable or inherently improved overall system resistance to leakage, did increase the overall probability of a leak in the system. NRC inspector guidance was issued on April 9, 1996, clarifying the thresholds for determining if an Unreviewed Safety Question existed. This guidance stated that "In considering the acceptability of a licensee's 10 CFR 50.59 evaluation, the staff has found compensating effects such as changes in administrative controls acceptable in offsetting uncertainties and increases in the probability of occurrence ... of an accident previously evaluated in the SAR ... provided the potential increases ... are negligible. Normally, the determination of whether there is an increase in the probability of occurrence ... of an accident previously evaluated in the SAR ... and whether such increases are negligible is based upon a qualitative assessment using engineering evaluations consistent with the original SAR analysis assumptions. The compensatory actions must clearly outweigh any potential increase in probability of occurrence ..." The inspectors did not observe any discussion in the SE of compensating effects or qualitative assessment of whether the probability increases were negligible. This issue will be reconsidered in the future and is an inspection follow-up item (IFI)(50-440/96003-04).

7.2 UFSAR FIGURE 9.1-9, FUEL POOL DEMINERALIZER SYSTEM (G41)

This figure showed that the elevation of the spent fuel pool overflow line was 689' and that 20 air-operated G41 valves were designed to fail open (FO) or fail closed (FC). The inspector reviewed safety evaluations (SE) 96-0063 and 96-0064 which were associated with Drawing Change Notices (DCN) No. 5050 and 5068 respectively. DCN 5059, dated March 27, 1996, removed the FC or FO notation from 20 valves on drawing D-302-653 because the valves actually failed "as-is" on loss of control air. The valves were all nonsafety-related valves within portions of the system bounded by safety-related valves so the earlier incorrect information had no potential safety consequences. The DCN had been initiated as a result of an investigation of PIF 94-2049, which, on October 28, 1994, had identified 16 FC designated valves that had failed "as-is" during implementation of a tag out.

DCN 5068, also dated March 27, 1996, changed the indicated elevation of the top of the containment upper pool overflow pipe from 689' to 688' - 10". The actual elevation, according to a survey (completed on December 6, 1995) by a licensee contractor, was 688' - 10 1/16", however, the inspectors concluded that the difference of 1/16" was within appropriate tolerances for this UFSAR figure. The overflow pipe helped to contain pool overflow water while helping to insure that there was sufficient water above spent fuel for adequate shielding. The earlier 2" error had minimal potential safety consequences. The licensee discovered this error in 1994 during a review of drawings. The drawing review had been performed during a Human Performance Enhancement System evaluation that had been done as a result of poor control of upper pool level that had been documented in Condition Report 94-304 on March 13, 1994. The licensee observed that drawing D-921-614 showed a different elevation than drawing D-302-651, which was part of UFSAR Figure 9.1-9. The inspectors also noted that areas of sheet 2 of Figure 9.1-9 were too faint to read. This issue will be reconsidered in the future and is an IFI (50-440/96003-05).

7.3 UFSAR FIGURE 9.3-34, MAIN REHEAT, EXTRACTION AND MISCELLANEOUS DRAINS

This figure showed a 3" line that drained condensate to the main condenser from before the seats of the inboard main steam isolation valves. There was no discussion of this figure in the UFSAR (Section 9.3.3.2.6). From this drain line, downstream of the containment isolation valves, a 3/4" drain line to atmosphere was shown. The 3/4" line had two drain valves in series, B21-F034 and F035. The 3/4" line was not safety-related. In February 1995 the licensee installed sealant in the 3/4" line upstream of B21-F035 to stop leakage past the valves. This was documented with a Mechanical Foreign Item (MFI) evaluation. The evaluation included an SE applicability check intended to determine the need for an SE. The applicability check erroneously concluded that the 3/4" drain line was not shown in the UFSAR. Therefore there was no SE performed prior to sealing the line. Sealing the line had no potential safety consequence. On March 26, 1995, during an evaluation of the MFI for conversion to a permanent installation, a design engineer recognized the error and documented it with PIF 96-1716. This issue will be reconsidered in the future and is an IFI (50-440/96003-06).

7.4 UFSAR SECTION 6.1, ENGINEERED SAFETY FEATURES MATERIALS

This section included a description of NUKON piping insulation used in the drywell. The insulation was described as fibrous glass (pad) material, encapsulated in woven glass (cloth) to form a composite blanket. This description was important because if the pad was not encapsulated by the cloth then the fibrous glass material could migrate to the suppression pool and foul the emergency core cooling system strainers. During a drywell inspection the inspectors observed that NUKON insulation on three of the inboard MSIVs had been pierced by large bolts or studs. This was corrected before the plant was started up. This issue will be reconsidered in the future and is an IFI (50-440/96003-07).

7.5 UFSAR SECTION 8.3.1.4.5, ELECTRICAL PENETRATION ASSEMBLIES

This section stated that "Any deterioration of the epoxy insulation is monitored by a leakage monitoring system using nitrogen. During normal operation, the nitrogen pressure will be kept at or above 15 psig (the Perry containment accident design pressure). This pressure is maintained in a small volume between the seals of each penetration module to achieve high sensitivity in leak monitoring. Penetration pressure will be routinely inspected during plant operation to assure prompt detection of leaky penetrations." The SER did not address pressure testing. SER Section 8.4.1 addressed "Containment Electrical Penetrations," but was silent on this issue. The SER listed IEEE Standard 317-1972 as the relevant standard, however UFSAR Table 1.8-1, "Conformance to NRC Regulatory Guides," stated that Perry conformed to IEEE Standard 317-1976, "IEEE Standard for Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations." Both versions of the standard required (4.5 in 317-1972, 5.1.3 in 317-1976) that the penetrations be designed and installed to allow gas leak rate testing after installation, but the standards did not specify periodic testing frequency or acceptance criteria, or discuss why such testing would be desirable. Regulatory Guide 1.63, Rev. 2 was listed in UFSAR Table 1.8-1 as the guide with which Perry conformed, this was consistent with the reference to IEEE Standard 317-1976. Regulatory Guide 1.63 provided no information on periodic gas leak rate testing.

The licensee normally pressurized the penetrations to 30 psig and checked the pressures every 2 weeks. When the "as found" pressures were less than 20 psig, the penetrations were repressurized to 30 psig. If the pressure was less than 15 psig, the shift supervisor was notified as well. The maximum expected accident pressure was 7.8 psig. Licensee QA personnel determined that although penetration pressures had been routinely inspected and repressurized, if necessary, no corrective actions had been taken for three penetrations that had often been found below 20 psig and occasionally below 15 psig. On one occasion, with the plant shut down, the pressure in penetration R72-S0028 was 5 psig. Although the UFSAR and referenced documents did not specify any corrective actions for low pressures there was an implied need to repair or evaluate penetrations that repeatedly lost pressure. This issue will be reconsidered in the future and is an IFI (50-440/96003-08).

7.6 UFSAR SECTION 9A.7, DEVIATIONS TO APPENDIX R

This section discussed the exceptions the licensee took to the requirements of 10 CFR Part 50, Appendix R, "Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979." The NRC documented the review of the exceptions in Supplement No. 7 to the SER. On November 14, 1995, during Audit 95-18, licensee QA personnel determined that Engineering Calculation P54-24, "Fire Load Calculations," had not been kept current. This was documented with PIF 95-2322. During the investigation of PIF 95-2322, licensee personnel concluded, in a memo dated January 3, 1996, that safe shutdown capability had been maintained even though 31 of 56 fire zones did not conform with the UFSAR. The memo also identified five additional fire protection issues including three fire zones with unapproved combustibles, a wall that needed its fire rating verified, and changes to a fire barrier that had made it different from the description in the UFSAR. On February 15, 1996, the licensee documented the additional fire protection issues. On February 20, 1996, licensee personnel identified unauthorized combustible material in Fire Zone 1AB-1g. This was documented in PIF 96-839. Fire Zone 1AB-1g was described in the UFSAR as including an area of separation between pressure transmitters. The UFSAR stated that, "Because of ... low fuel load and lack of intervening combustibles, it is unlikely that a fire would disable redundant transmitters." The transmitters, located at the 574' elevation of the auxiliary building, were separated by about 35 feet. Licensee personnel observed six plastic tool cases and some plastic bags in a tool cage within the combustible-free area. The inspectors verified that the combustible materials had been removed and observed that a permanent metal sign had been posted classifying the cage as a "Combustible-free Area." This issue will be reconsidered in the future and is an IFI (50-440/96003-09).

7.7 UFSAR SECTION 9.2.6, CONDENSATE STORAGE FACILITIES

This section included Figure 9.2-13, "Condensate Transfer and Storage System" and stated that, "This system is not classified as a safety class system." The condensate storage tank (CST) was part of this system and was referenced in the Technical Specifications (TS). The basis for the applicable TS also stated that no credit was taken in the safety analysis for CST water.

However, TS Surveillance Requirement 4.5.2.2 required that "The HPCS system shall be determined OPERABLE at least once per 12 hours by verifying the condensate storage tank required volume when the condensate storage tank is required to be OPERABLE per specification

3.5.2.e." This was when suppression pool level was below 16'6" while the plant was in OPERATIONAL CONDITION 4 AND 5. Although the surveillance requirement did not provide total assurance that the appropriate parameter would be measured, the inspectors' review of the TS Rounds Log verified that the licensee complied with the apparent intent of the TS by checking the volume of water in the CST.

The CST was shown on Figure 9.2-13 with various levels of water marked, along with associated tank water volumes. The inspectors noted that there appeared to be discrepancies among the various levels and confirmed the discrepancies with calculations. The inspectors could not find a specified number of gallons per inch in the UFSAR or Plant Data Book and asked the operators on shift if they knew where to find the number. The operators did not know, but a short time later the Shift Technical Advisor informed the inspectors that the plant computer used a value of 1,223 gallons per inch, which was close to one of the values (1,222 gallons per inch) the inspectors had calculated. The inspectors asked licensee compliance and engineering personnel why the numbers would be different and were later informed that some of the numbers were wrong. The licensee stated that they had discovered this error in 1995 during their self assessment based on the NRC System Based Instrument and Control Inspection module (discussed in Inspection Report Nos. 440/95002 and 440/95006). Licensee personnel had later decided that it would not be necessary to change the incorrect numbers shown on the UFSAR figure. The licensee stated that they had re-evaluated that decision and were developing a change to the UFSAR, which would include consideration of the need for an SE. The licensee also stated that they had begun training to increase sensitivity to the need to correct UFSAR errors. This issue will be reconsidered in the future and is an IFI (50-440/96003-10).

7.8 UFSAR SECTION 10.2.5, HYDROGEN AND CARBON DIOXIDE SYSTEMS

This section stated that these systems served no safety function. The licensee determined that 1/2" to 3/4" piping expanders shown on UFSAR Figure 10.2-4, "Hydrogen Supply System," did not exist because bushings were provided in valves 1N35F503A and B to allow the 3/4" valves to be used with the 1/2" piping without piping expanders. The licensee prepared a UFSAR change request with an SE to correct the UFSAR to match the actual plant conditions. The inspectors determined that the previous deviation of the plant from the description in the UFSAR had no potential safety consequences. This issue will be reconsidered in the future and is an IFI (50-440/96003-11).

7.9 UFSAR SECTION 10.4.2, MAIN CONDENSER EVACUATION SYSTEM

This section stated that one steam jet air ejector set (SJAE) was normally in service with the other set available as a spare. It also stated that the system was classified as Quality Group D, as defined by Regulatory Guide 1.26. In the fall of 1993, the licensee removed a leak seal clamp that had been installed in 1987 on the stainless steel bellows immediately downstream of the 'B' SJAE. When the seal clamp was removed the licensee discovered that the bellows had broken into pieces. About 20% of the pieces could not be found. The SJAEs discharged to the off gas system and the licensee concluded that the missing bellows pieces had migrated to the off gas system. The bellows was replaced with a spoolpiece. The licensee decided that the USAR implied that the off gas system did not have broken bellows pieces in it and performed a safety evaluation of the change in the off gas system. The safety evaluation concluded that the system could be used temporarily without finding and removing the lost pieces because there was a "negligible" increase in probability of degraded off gas system performance and because the off gas system was "not considered 'important to safety'." The off gas system is used to control the release of gaseous radioactive effluent. The licensee also decided to restrict the use of the 'B' SJAE and normally use the 'A' SJAE. During RFO5 the licensee could find only a few additional small pieces of the failed bellows. The licensee performed another safety evaluation and determined that the system could be used permanently without finding the missing bellows pieces and did not include the earlier restriction on the use of the 'B' SJAE. The conclusion of the new SE was based on the same reasons as the original SE. The SEs did not refer to Section 10.4.2 in the list of applicable sections of the UFSAR. This omission did not appear to have any impact on the quality of the safety evaluations. This issue will be reconsidered in the future and is an IFI (50-440/96003-12).

7.10 UFSAR SECTION 15, APPENDIX 15B RELOAD SAFETY ANALYSIS

This appendix included information on changes in reactor core design and how they affect the core design as described in the main text of the UFSAR. Most of the information in this appendix was provided by the fuel manufacturer, General Electric (GE). During the inspection period, GE notified the licensee of four errors or problems that affected the analyses used to develop the appendix. On March 12, 1996, GE notified the licensee that some fuel pellets in the reload fuel may be less dense than specified (PIF 96-1389). On March 13, GE notified the licensee of an error in the emergency core cooling system analysis caused by their failure to consider flow through the reactor bottom head drain (PIF 96-1422). Initial evaluation of these two conditions determined that they would have minor impact on fuel rod peak center line temperature during bounding transients.

On March 28, 1996, GE notified the licensee of four errors in various computer programs used for core and fuel bundle design. Initial evaluation of these errors indicated that they would have no impact at Perry. On April 3, 1996, GE notified the licensee that there was an error in GE's methodology for calculating the minimum critical power ratio (MCPR) safety limit. Since the error was not conservative, the licensee provided instructions to the operators to limit the indicated maximum fraction of limiting critical power ratio (MFLCPR) to .985 instead of 1. MFLCPR was the operating limit used by the operators to insure compliance with the MCPR safety limit. After GE discussed the issue with the NRC at NRC headquarters on April 17, 1996, the licensee reduced the MFLCPR limit to .98. The inspectors verified that MFLCPR was consistently below the new limit at about .85.

The licensee evaluated each situation to determine in an SE was required. The inspectors concluded that appropriate SEs were prepared after the problems were identified. This issue will be reconsidered in the future and is an IFI (50-440/96003-13).

7.11 UFSAR TABLE 1.8.1, CONFORMANCE TO NRC REGULATORY GUIDES

This Table stated that testing of absorption units would conform with Regulatory Guide 1.52, Rev. 2, with the exception that testing would be performed in accordance with ANSI N510-1980 instead of ANSI N510-1975. The testing was performed on the charcoal absorbents in the safety-related annulus exhaust gas treatment and fuel handling area ventilation systems. On April 3, 1996, licensee quality control personnel determined that the 1979 ASTM-D3803 Standard and the Technical Specifications had not been invoked on January 8, 1996, by the purchase order for adsorbents, as required by ANSI N510-1980. Instead, the licensee had typically invoked ASTM-D3803, 1986, and identified plant specific data, and had invoked Protocol INEL EGG-CS-7653 to replace other testing identified in the Regulatory Guide. Licensee engineering personnel performed a preliminary review of the ASTM-D3803 standards and determined that since the test method criteria was identical there was no impact on equipment performance. Licensee personnel also initiated PIF 96-1835 for further evaluation of this condition. The PIF included a recommendation for a UFSAR change, which would include consideration of the need for an SE. This issue will be reconsidered in the future and is an IFI (50-440/96003-14).

7.12 UFSAR TABLE 6.5.1, COMPARISON OF CONTROL ROOM EMERGENCY RECIRCULATION SYSTEM WITH REGULATORY GUIDE 1.52 POSITIONS.

The "System Design Feature" listed for Regulatory Position 5.a(3) was that "Plant operating procedures will conform with the requirements of this position." This may not be the case because of the discrepancy identified in the discussion described in Section 7.11. This issue will be reconsidered in the future and is an IFI (50-440/96003-15).

7.13 UFSAR TABLE 6.5.2, COMPARISON OF FUEL HANDLING AREA EXHAUST SUBSYSTEM WITH REGULATORY GUIDE 1.52 POSITIONS

The "System Design Feature" listed for Regulatory Position 5.a(3) was that "Plant operating procedures will conform with the requirements of this position." This may not be the case because of the discrepancy identified in the discussion described in Section 7.11. This issue will be reconsidered in the future and is an IFI (50-440/96003-16).

7.14 UFSAR TABLE 6.5.3, COMPARISON OF ANNULUS EXHAUST GAS TREATMENT SYSTEM WITH REGULATORY GUIDE 1.52 POSITIONS

The "System Design Feature" listed for Regulatory Position 5.a(3) was that "Plant operating procedures will conform with the requirements of this position." This may not be the case because of the discrepancy identified in the discussion described in Section 7.11. This issue will be reconsidered in the future and is an IFI (50-440/96003-17).

7.15 TABLE 9A.3-2, EMERGENCY LIGHTING SELF-CONTAINED LIGHTING PACKS WITH 8-HOUR BATTERIES

This table showed functions of 10 CFR Part 50, Appendix R, emergency lighting units. During an inspection of the safety-related switchgear rooms, the inspectors observed two emergency lights that appeared to be pointed at a location where their light would serve no useful purpose. The inspectors used the UFSAR (Table 9A.3-2) to evaluate the condition. The inspectors determined that one lamp each on lighting units R71-L0214C, R71-S0215A, and R71-S0216A were not providing illumination as described in the UFSAR. Also, due to the location of the lighting units and other equipment in the room, it was not possible for lighting unit R71-L0216B to illuminate Motor Control Center EFIC as described in the UFSAR. There was no known SE for this condition. See Section 4.4. The licensee had not developed its corrective actions for this issue by the end of the inspection period. This issue will be reconsidered in the future and is an IFI (50-440/96003-18).

8.0 Persons Contacted and Management Meetings (Exit)

8.1 Management Meetings

On March 11 and 12, 1996, the NRC Region III Regional Administrator inspected the plant and met with various members of the licensee's staff to discuss current plant issues.

On April 18-19, 1996, the Director, Project Directorate III-3, DRP-III/IV, ONRR inspected the plant and met with various members of the licensee's staff to discuss current plant issues.

8.2 Exit Meeting

The inspectors contacted various licensee operations, maintenance, engineering, and plant support personnel throughout the inspection period. Senior personnel are listed below.

At the conclusion of the inspection on April 19, 1996, the inspectors met with licensee representatives (denoted by *) and summarized the scope and findings of the inspection activities. The licensee did not identify any of the documents or processes reviewed by the inspectors as proprietary.

D. C. Shelton, Senior Vice President
*R. D. Brandt, General Manager Operations
*N. L. Bonner, Engineering Director
*R. W. Schrauder, Nuclear Services Director
*L. W. Worley, Nuclear Assurance Director
*M. B. Bezilla, Operations Manager