U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos. 85-46; 85-10

Docket Nos. 50-352; 50-353

License Nos. NPF-39; CPPR-107 Priority -- Category C;A

Licensee: Philadelphia Electric Company
2301 Market Street
Philadelphia, Pennsylvania 19101

Facility Name: Limerick Generating Station, Unit 1 & 2

Inspection Conducted: December 1, 1985 - January 10, 1986

Inspectors: E. M. Kelly, Senior Resident Inspector
S. D. Kucharski, Resident Inspector
M. Miller, Radiation Specialist
P. Clemons, Radiation Specialist

Reviewed by: J E Beall 2/24/86
J. E. Beall, Project Engineer date

Approved By: Robert M. Gallo 2/24/86
R. M. Gallo, Chief, Reactor Projects Section 2A date

Inspection Summary: Combined Inspection Report for Inspection Conducted December 1, 1985 - January 10, 1986 (Report Nos. 50-352/85-46; 50-353/85-10)

Areas Inspected: Routine and backshift inspections by the resident inspectors and region-based inspectors consisting of followup on outstanding items; observation and review of TC-6 startup testing; system walkdown of the CREFAS system; plant tours including cold weather preparations; maintenance and surveillance observations; and review of LERs and periodic reports. Events which occurred during the period, and were reviewed, include: IRM replacements; reactor scram on December 8; cross-around piping steam leak on January 2; and main generator isophase bus duct heating. This report also reviewed the radwaste transportation program with respect to package selection, QA and shipping activities. The report documents a meeting held on December 7, 1985 regarding excess flow check valve testing.

Results: Two unresolved items were identified, associated with radwaste package certificates of compliance (Detail 9.1) and review of radwaste cask loading procedures (detail 9.2). No violations were identified. This inspection involved 209 hours of onsite inspection of Unit 1 and 9 hours of Unit 2 by the resident inspectors and two Region I radiation specialists.

DETAILS

1.0 Persons Contacted

Philadelphia Electric Company

J. Clarey, Construction Superintendent
J. Corcoran, QA Field Section Head
J. Doering, Operations Engineer
R. Dubiel, Senior Health Physicist
P. Duca, Technical Engineer
L. Dyer, QA Engineer
J. Ferguson, Radwaste Consultant (Bechtel)
K. Folta, Operations Quality Control Site Supervisor (Gilbert)
J. Franz, Superintendent of Operations
A. Jenkins, GE Startup Manager
G. Leitch, Station Manager
J. Spencer, Plant Services Superintendent

Also during this inspection period, the inspectors discussed plant status and operations with other supervisors and engineers in the PECo, Bechtel and General Electric organizations.

2.0 Followup on Unresolved Items

2.1 (Closed) Unresolved Item 85-30-05: BISCO Seals

This item concerned voiding discovered in 77 cable tray penetrations sealed with the BISCO SF-20, a 3-hour fire rated barrier material which has a fast expansive property. The licensee instituted temporary repairs and implemented compensatory fire watches until a permanent repair method could be completed.

The inspector reviewed BISCO Repair Procedure SP-15A which was used to effect the permanent repair as part of modification package (MDCP)-85-652 issued on September 13, 1985. The rework consisted of a review, inspection and repair of all existing cable tray penetrations sealed using BISCO Detail 27 which included a ceramic board that acted as a tanning material and was left in-place after the SF-20 material cured. The temporary repair materials were removed and all penetrations were returned to their original design configuration using SF-20 foam and the ceramic board. A revised installation procedure used a temporary foam board during the pour which did not stick to the foam outer surface and was then removed to allow for more effective surface inspection of possible voiding. A non-conductive wooden dowel was also used to poke through and inspect for internal voids. A caulk was used to re-plug the inspection holes. Two BISCO technicians installed the foam and these personnel were experienced with the application and the Detail 27 installation. BISCO in-process QC inspections checked all penetrations for completeness of fill, proper SF-20 cell structure, an absence of voiding and final dam board installation. The inspector reviewed a safety evaluation for MDCP 85-652 which addressed the repair and inspection of all Detail 27 penetrations. The safety evaluation was presented to and approved by the PORC in Meeting 85-081 on September 13, 1985. The inspector noted that the new repair procedure called for application of the SF-20 foam in lifts which greatly reduced the possibility of internal voiding, as opposed to application via a single pour. Also, the new inspection criteria using a dowel probe and a temporary foam board significantly improved the capability to detect voiding.

The inspector reviewed licensee surveillance report SCR No. C-280 which documented E&RQA inspection of five penetration seals for possible voiding, pour technique, permanent dam installation, and SF-20 color and cell structure. The report concluded that the rework was in accordance with the procedure and was satisfactory. The inspector also reviewed E&R QA Audit Report AR-342 which evaluated BISCO compliance with QA Program procedures for records management, installation activities, materials control and personnel training and qualification. The report concluded that BISCO QA was adequate and effectively implemented. The inspector noted that BISCO quality measures were evident and that the licensee had applied adequate quality oversight and audit activity. One nonsafety-related penetration seal (PSA-335-E001) remained to be re-worked. The penetration is located in the Turbine Enclosure and separates non-safeguards areas which are not required by Technical Specifications to be sealed. Compensatory fire watches were stopped on October 3, 1985, after completion of rework. The inspector toured the Control Structure and observed the final configuration of several re-worked penetrations. The inspector had no further questions and this item is closed.

2.2 <u>(Closed) Unresolved Item 84-68-02; Toxic Gas Monitor Calibration</u>

This item concerned documentation showing that toxic gas monitors were properly calibrated for phosgene, and that the alarms were properly set for the toxic gases listed in Technical Specification 3.3.7.8.2. The inspector reviewed documentation that stated the detector and central (common) processor unit were calibrated and certified by the vendor prior to installation. The alarm function is then field-checked using any of the challenge gases, because the alarm function is independent of the gas type. With regard to the alarm set point for phosgene, which uses the ethylene oxide (ETO) channel, the setpoint was lowered from 50 parts per million (ppm) to 3.5 ppm to account for the reduced sensitivity of the detector for phosgene.

The licensee was informed of this problem by the vendor on July 22, 1985 and subsequently lowered the toxic gas setpoint on the ETO channel alarm. The licensee issued LER-85-065 on August 28, 1985, describing this event. The inspector reviewed the LER, discussed the item with licensee representatives, and had no further questions.

2.3 (Closed) Inspector Follow Item 85-26-03; Process Control Program

This item concerned the status of the licensee's program for implementation of their Process Control Program (PCP) and readiness to ship radioactive waste. The inspector reviewed the revised licensee procedures, which implement the PCP and ensure compliance with radioactive waste shipping. The procedures were organized into Radioactive Waste, Shipping and Surveillance Test procedures for improved delineation of responsibility. The inspector noted that the licensee was prepared to make radioactive waste shipments from a procedural standpoint. The inspector had no further questions.

2.4 (Open) Inspector Follow Item 85-40-01; Respiratory Protection Program

This item concerned revised respiratory protection program procedures. The licensee had revised their procedures to address whole body counting if facial contamination was detected in excess of 100 counts per minute above background; and to ensure Health Physics Senior Technician signoff to indicate review of the Maximum Permissible Concentration (MPC) Log. The licensee also performed an inventory of respiratory protection equipment on October 31, 1985, and issued Procedure HP-512, Revision 2 to require quarterly inventories. The licensee had not completed revising the procedures that will address emergency entry into life threatening environments and contamination surveys for supplied air systems. This item remains open and will be reviewed during a subsequent inspection.

2.5 (Open) Unresolved Item 85-36-02; Unit 2 Flood Barriers

The inspector observed the condition of and administrative controls imposed upon the engineered barriers outlined in the information provided in LER 85-080, Supplement 1, issued on December 12, 1985. Each of the barriers consist of steel deck sections welded or bolted to structural steel members attached to building concrete via expansion anchors. Two of the barriers consist of moveable sections hinged on one side and secured with a lock pin on the other. The inspector verified that the moveable sections were locked closed and controlled such that shift supervision authorization would be required to open these barriers. The inspector reviewed Operations Memorandum OPS-0012 dated December 5, 1985, which described the potential flood path through the Unit 2 Turbine Enclosure and its effect on the Control Structure chillers including the installed temporary barriers, and procedure ON-115 which describes actions to be taken in the event of the loss of both chillers. The memo was addressed and provided to control room shift personnel, and was implemented by Control Room Standing Order OPS-0013 dated December 5, 1985, which directed that the hinged barriers be opened only on shift supervision authorization with posting of an individual at the barrier. The inspector discussed this event and the barrier controls with various licensed operators, all of whom were knowledgeable of the issue.

The inspector also attended the meeting described in LER 85-080, Supplement 1, held onsite on December 5, 1985. The discussion of flow paths and maximum precipitation levels presented in the LER were representative of the information presented in the meeting. That portion of unresolved item 85-36-02 relating to administrative controls placed on the moveable barriers is resolved. However, pending a permanent modification to seal the penetrations providing a flood path into the Control Structure, this item remains open.

3.0 Review of Plant Operations

3.1 Summary of Events

The plant remained in Operational Condition 1 between 65 and 100% power through most of this inspection period, in the final phase of TC-6 startup testing.

An unplanned scram occurred on December 8 from 62% power due to a recirculation pump flow control fault. The scram is addressed in Detail 4.2. A planned scram occurred on December 18 as a result of startup test STP 25.3, Full MSIV Isolation, from 92% power, and is discussed in Detail 7.1. The unit experienced main generator isophase bus duct heating problems at power levels greater than approximately 70%. This problem restrained power operation above 70% until repairs were made following STP 25.3 on December 19-20. The repairs did not eliminate the hot spots (discussed in Detail 8) altogether, and licensee personnel have been trending a single hot spot through this inspection period.

The unit reached full rated power for the first time on December 26, 1985, and operated at 99% power until January 2, 1986. Because of a 30 MWe discrepancy in expected versus experienced generator output first discovered on December 29, the licensee investigation found a steam leak in the main turbine cross-around piping which was caused by a turbine cross-around line safety valve lift and subsequent rupture of an expansion joint (see Detail 6.2). A decision was made to conduct startup test STP 27.4, Turbine Trip, from 99% power (Detail 7.2), and then replace the expansion joint and inspect the five other safety valves and expansion joints. The safety valves were found to be set lower than designed and were reset on January 10. Plant startup was begun on January 8 and continued through the end of the inspection period. The startup was suspended on January 10 due to the numbers 1 through 5 combined intermediate valves being stuck closed. The valves were heated and successfully opened, and the reactor was at 50% power on January 11, 1986.

A Pennsylvania PUC decision was issued on December 5, 1985, recommending completion of Unit 2 under a 3.2 billion dollar cost cap. The licensee's Board of Directors voted on December 23 to begin construction early in 1986.

3.2 Operational Safety Verification

The inspector toured the control room daily to verify proper manning, access control, adherence to approved procedures, and compliance with LCOs. Instrumentation and recorder traces were observed and the status of control room annunciators was reviewed. Nuclear instrument panels and other reactor protective systems were examined. Effluent monitors were reviewed for indications of releases. Panel indications for onsite/offsite emergency power sources were examined for automatic operability. During entry to and egress from the protected area and vital island, the inspector observed access control, security boundary integrity, search activities, escorting and badging, and availability of radiation monitoring equipment including portal monitors.

The inspector reviewed shift superintendent, control room supervisor, and operator logs covering the entire inspection period. Sampling reviews were made of equipment trouble tags, night orders, and the temporary circuit alteration and LCO tracking logs. The inspector also observed shift turnovers during the period. The operations activities observed were performed in accordance with the applicable procedures and requirements and found acceptable.

3.3 Station Tours

The inspectors toured accessible areas of the plant throughout this inspection period, including: the Unit 1 reactor and turbine-auxiliary enclosures; the main control and auxiliary equipment rooms; emergency switchgear and cable spreading rooms, diesel generator and radwaste enclosures; the spray pond and pumphouse, and the plant site perimeter. During these tours, observations were made relative to equipment condition, fire hazards, fire protection, adherence to procedures, radiological controls and conditions, housekeeping, security, tagging of equipment, ongoing maintenance and surveillance and availability of redundant equipment.

No violations were identified.

3.4 ESF System Walkdown

The inspector independently verified the operability of the Control Room Emergency Fresh Air Supply (CREFAS) system by performing a walk-down of the accessible portions of the system, and confirmation of the following items:

-- the system check-off list and operating procedure are consistent with the plant drawings and as-built configuration

-- identification of equipment conditions and items that might degrade performance

-- dampers and breakers were properly aligned, necessary instrumentation was functional

-- control room switches, indications and controls are satisfactory

The following references were reviewed:

-- Technical Specification Section 3.7.2

-- Process & Instrumentation Diagram M-78

-- FSAR Section 6.5.1.2

-- CREFAS Operating Procedure S78.1

No unacceptable conditions were identified.

3.5 Cold Weather Preparations

The inspector reviewed the licensee's program to prepare the plant for cold weather operations. This program is described in General Plant Procedure GP-7, Cold Weather Preparation and Operation, Revision 0, November 30, 1984. The program consists of a series of valve and switch check off lists which aligned: HVAC systems in critical areas; heat tracing for critical components; and circulating and service water systems to operate in their winter modes. The program was completed on October 30, 1985, before the procedurally-required completion date of November 15, 1985.

The inspector reviewed system operating procedure SO 8.8.A, Refueling Water Storage Tank (RWST) and Condensate Storage Tank (CST) Freeze Protection, Revision 0, March 7, 1983, which is one of the required procedures to be completed for cold weather operation as specified by GP-7. All the necessary valve and switch manipulations had been implemented to adequately protect the CST and RWST from cold weather. The inspector did note that in step 8.2.A of the procedure, the #1 CST local temperature indicator was incorrectly referenced as TISL 08-114. The indicator on the tank is labeled TISL 08-113. This was brought to the attention of the shift superintendent. The inspector had no further questions at this time.

The inspector also verified the removal of temporary circuit alteration (TCA)-351 on December 23, 1985. TCA-351 was applied on August 27, 1985, to add a plywood barrier at the spray pond spillway and effectively raise the normal spillway height by 10 inches. The TCA was initially reviewed in Inspection Report 50-352/85-30, where a concern was raised for pond freezing and potential board damage. The inspector observed that the board had been removed subsequent to December 23, 1985, and had no further questions.

No violations were identified.

4.0 Event Followup

4.1 Neutron Detector Replacements

A plant startup was begun on November 18, 1985 following repairs on the number 6 combined intermediate valve. The startup was suspended on November 19th because of erratic response from the D intermediate range monitor (IRM). I&C technicians investigated the D IRM, which first indicated no response at 9:14 p.m. on November 18, 1985. The detector was subsequently declared inoperable. Two other IRMs (F and C) had been previously declared inoperable, and the F channel was therefore placed in the tripped condition in accordance with Technical Specifications which resulted in a half-scram signal being present.

The licensee made a decision to replace the three inoperable IRMs and made preparations for the replacements by contacting two other facilities to determine the anticipated radiation and contamination levels. Dose rates were not expected to exceed 5R/hr and no contamination was expected. A pre-job briefing was conducted and plans were made to sleeve the detectors during removal to limit exposures. The approximate length of the cable in relationship to detector location was also known. The licensee removed the three faulty IRMs and one SRM between 2 and 5 a.m. on November 22nd. The detector cables were pulled and cut in 10-foot lengths, within plastic sleeves, and placed in shielded containers. Initial removal of the first IRM was suspended at 2:30 a.m. because of a higher-than-expected exposure level of 30

R/hr which was attributable to a short-lived neutron activation product, sodium-24 (14 hour half-life). The sodium isotope apparently originated from fiberglass sheathing on the detector cable used for thermal and electrical insulation. Maintenance technicians involved with the removal of the "F" IRM entered the drywell at 1:06 a.m. and left at 2:13 a.m., after radiation levels exceeded 10 R/hr on contact with the cable. Two of these workers received skin (facial) contamination, and had to be decontaminated. The highest direct frisk reading experienced was 500 counts per minute (cpm) on the face, and a nasal swipe indicated 120 cpm. Following decontamination, the highest whole body dose measured was 50 mRem, and no internal exposure was measured. Of the ten personnel involved (including HP technicians), whole body exposures measured from 5-10 mRem. Floor contamination under the vessel measured from 30 to 200,000 dpm per 100 cm^2 (removable), and an air sample indicated approximately 4% maximum permissible concentration (MPC) per 10 CFR Part 20, which was predominantly sodium-24.

The reactor was critical from 9 p.m. on November 19th until approximately noontime on November 20th. This accounted for the activity experienced from the activated sheathing about 12 hours later. The inspector concluded that, during the removal of the IRM, the detector cable length was shorter than its expected length, exposing the detector sooner than expected. In addition, radiation levels on the cable were higher than expected due to decreased decay time allotment and activation of sodium-24. Workers had been wearing facial shields and extremity (finger) dosimetry in addition to the routine Radiation Work Permit protective requirements. A shield for the IRM was also available at the job site. The licensee conducted a post-job review of the events related to the IRM removal. The inspector reviewed the draft post-job ALARA review and had discussions with the Senior Health Physicist to determine what pre-planning and radiological controls had been taken to maintain exposures ALARA. No radiation exposures in excess of the limits of 10 CFR Part 20 occurred and no whole body activity was detected. The highest whole body dose did not exceed 50 mRem and the highest extremity dose was 600 mRem. The inspector noted that an adequate critique of the above events was performed in a timely manner. Subsequent removal of other IRMs was completed without incident. No violations were identified.

4.2 Flow-Biased High Power Scram on December 8, 1985

A reactor scram occurred at 12:33 p.m. on December 8, 1985 as a result of a failure of the "B" recirculation pump speed controller. Controller demand signal had been observed failing down scale earlier in the day, and troubleshooting was performed with the pump's scoop tube locked. When the controller was balanced and put in reset, pump speed increased and reactor power increased from 61 to 84%. The consequent increase in pump speed and core flow caused a high flux scram. Vessel level dropped to plus 8 inches, and the main turbine subsequently tripped on generator reverse power. All other systems functioned properly, and no ECCS actuations occurred. The inspector reviewed the GP-18 Scram Review Procedure for this event and verified proper post-trip conditions. An Unusual Event was declared at 12:55 p.m. and was terminated at 1:20 p.m.

Licensee investigation of this event attributed the cause to a loose connection in the pump speed control circuitry. The loose connection created a fault at the input to an isolator card between the controller demand signal and an inner loop error signal, resulting in a misleading indication of speed demand in the main control room. When operators attempted to balance actual and demand speeds prior to reset of the locked scoop tube positioner, a significant mismatch existed, between actual and demand signals, which was not apparent. The licensee identified the isolator fault after the scram and initiated a temporary circuit alteration, pending a permanent modification, adding a more accurate method of balancing scoop tube position demand and pump M-G set speed. As discussed in GE Information Letter (SIL) No. 363 dated September 1981, a deviation meter was installed locally for both recirculation pump M-G sets. The deviation meter along with revised procedural direction to operators, should ensure that the actual and demand signals are matched prior to unlocking the scoop tube positioner.

The inspector reviewed SIL-363 and discussed this event with licensee I&C engineers. Temporary Circuit Alteration (TCA) #452 was implemented on December 9, 1985, installing the deviation meters locally at both recirculation pump MG-sets. Station Procedure S43.0.A, Resetting a Scoop Tube Lock-Up, was revised to dispatch the operator to read the local deviation meter and, if necessary, adjust the pump speed controller until the meter stabilizes within an acceptable band of speed/demand balance. The inspector reviewed Procedure S43.0.A and verified that the deviation meters were installed and that recirculation pump speed and demand signals were essentially the same as indicated on control room meters during reactor operation. Recirculation flow control circuits were reviewed using GE Elementary Drawing E-19.20. The scram was described in LER 85-095 issued on January 7, 1986, which attributed the fault at the isolator to loose wire connections that were tightened. No further problems have been experienced with the recirculation flow control circuitry. The inspector reviewed LER 85-095 and had no additional questions.

4.3 Main Turbine Crossover Piping

4.3.1 Power Discrepancy

A steam leak in the north condenser bay area of the Unit 1 Turbine Enclosure was discovered between 1:00 and 2:00 pm on January 2, 1986, which was later confirmed to be caused by a ruptured expansion joint in a 24-inch safety valve discharge line from the high-to-low pressure turbine cross around steam piping to the main condenser. The steam leak was sufficient to cause a 20-30 MW discrepancy between expected and actual electrical generator output power, and eventually resulted in a plant shutdown on the evening of January 2, 1986.

The discrepancy in generator output power was first noticed by operators on the afternoon of December 29, 1985, following turbine stop and control valve testing. Reactor power had been reduced from 96% to 70% for the valve testing and, following restoration of power to 98% after the tests, plant efficiency was observed to decrease from 0.345 to 0.330. The decrease was observed as a reduction in expected generator electrical output from approximately 1090 to 1060 MWe. The 30 MW discrepancy existed until early on December 31 when, after similar turbine valve testing, generator output increased to 1090 MWe - the expected electrical output for reactor power (96%) at that time. However, additional turbine valve testing in the afternoon on December 31 was again followed by a difference in expected versus actual electrical output of about 30 MW.

The licensee had commenced an investigation of secondary plant steam production and efficiency to determine the cause of the power discrepancy. A plot of plant power operation over the period in question was constructed which, when coupled with the later knowledge of the expansion joint steam leak, pointed to the opening of the Number 1 crossover line safety valve which bypassed a portion of steam flow directly to the condenser. The capacity of the safety valve was sufficient to result in the observed loss of turbine efficiency and power. Following discovery of the expansion joint steam leak, which most probably began early on January 2, 1986, the licensee reduced reactor power in an attempt to stop the steam leak. However, the rupture in the expansion joint then allowed air inleakage to the condenser and condenser vacuum was observed to decrease. The power reduction sufficiently lowered crossover steam pressure to close the safety valve and terminate the steam leak, but the air inleakage to the then-ruptured expansion joint caused a rapid decrease in condenser vacuum.

4.3.2 Radiological Considerations

The inspector interviewed various plant personnel, including health physics technicians, engineers and the Station Manager. Shortly after noontime on January 2, 1986, the north exterior wall of the Turbine Enclosure was observed to be dripping moisture from seams in the precast concrete overhang near the condenser bays. The licensee representatives stated that the apparent condensation of warm moist air inside the Turbine Enclosure had not been observed on the morning of January 2. Health physics surveys and samples were collected at 3:07 p.m. on January 2. The samples included smears taken from the immediate ground area, indicating measurable contamination above background levels. Buckets had been placed under the paths observed for the moisture condensation and a sample of one of these buckets counted at 3:47 p.m. showed low levels of gross gamma activity which was determined to be two short-lived isotopes, nitrogen-13 (N13) and flourine-18 (F18). The following concentrations were back-calculated to the reference time of 3:20 p.m. when the sample was taken:

Isotope	Half-Life (minutes)	Measured Concentration (microcuries per cc)
N13	9 minutes	1.6×10^{-3}
F18	109 minutes	4×10^{-4}

The F18 concentration was approximately 50% less than the allowable concentration per 10 CFR Part 20 for release in unrestricted liquid form. Samples taken later at 5:00 p.m. on January 2nd from the buckets and nearby drains showed no measurable contamination. The buckets were kept in-place until the following day, and after the reactor had been shutdown on the evening of January 2nd. The licensee estimated that an upper bound on the water collected by the buckets was about 100 gallons, but approximately 10% of that or 10 gallons was thought to be derivative from the condensed moisture which seeped through the Turbine Enclosure wall. The total amount collected was also indistinguishable from exterior moisture (including rain on the morning of January 3, 1986) which also was collected in the buckets. The radiological significance of this event was minimal, and is further discussed in NRC Inspection Report 50-352/86-02.

The inspector observed the interior details of the Unit 1 Turbine Enclosure north wall and compared these with details shown on structural drawings A-112 and C-112. The location of a steel beam at the interior of the wall was the probable path through which steam and moisture condensed, collected and ran underneath and through wall joints and eventually outside. The licensee's construction engineers stated that proposals for caulking or otherwise sealing the leakage path were being considered.

4.3.3 Maintenance on Crossover Relief Valves and Crossover Piping Expansion Joint

During the period January 3 through 7, 1986, the inspector reviewed maintenance activities associated with the repair of a main turbine crossover steam piping expansion joint, and the reset of the crossover piping relief valves, to verify compliance with the station's administrative procedures and to assess the technical adequacy of the repair techniques.

The inspector observed the condition of the expansion joint on the number 1 cross-over piping discharge, from safety valve PSV-01-120C into the main condenser. The joint had ruptured at two locations, circumferentially, and the bellows had failed due to postulated fatigue of an internal deflection piece which was missing. The joint was removed and replaced, and five other similar expansion joints were inspected and found satisfactory. The cause of the ruptured joint was premature lifting of the upstream safety relief valve, probably between December 29 and 31, 1985. The plant operated at power levels of 95-99% during that period. Steam pressure in the crossover piping between the high and low pressure turbines at 95-100% power levels were expected to be about 170 psig, however, this pressure is not directly monitored.

The six safety valves on each of the crossover steam lines were initially set in April 1985 within 3% of nameplate pressure settings, i.e. 200 to 214 psig. The settings were subsequently found to be approximately 10-20 psi lower than initially left, and were re-adjusted on January 9 and 10, 1986. The following table describes the safety valve pressure setpoints:

Settings (All in psig)

Crossover Line	Safety Valve	Nameplate Setting	As-Left April 1985	As-Found January 1986	As-Left[b] January 1986
1[a]	120C	198	199.5	183.5	204
2	120B	205	205	183	207
3	120A	212	210	188	216
4	121A	202	207	199	204
5	121B	209	205	187	208
6	121C	216	214	196	216

Notes:

a. Replaced with new valve

b. With steam and vacuum

Safety valve PSV-01-120C pressure setpoint was found to be set closer to the operating steam pressure in the crossover steam lines than originally intended. The inspector discussed the determination of valve setpoint with the maintenance engineer, and the uncertainties associated with that process. The inspector concluded that the crossover piping safety valves are unique in that the condenser vacuum on the valve bonnet side assists in valve lift. The inspector found that the re-settings of the safety valves on January 9 and 10, 1986, were carefully and consistently performed.

The inspector reviewed maintenance request MRF-0095 approved on January 3, 1986, for the inspection of the ruptured expansion joint. Visual examinations on January 8 confirmed two linear ruptures (one 10 inches and one 4 inches long) and all four inner deflection shields were damaged or cracked. The expansion joint was removed and replaced on January 9, welded into the 24-inch cross-around relief line to the main condenser. Removal and replacement of safety valve PSV-01-120C was performed under MRF-86-0112 on January 8. The inspector discussed this maintenance activity with the Maintenance Engineer, periodically observed the progress of the visual inspections and repair work, and confirmed proper ALARA considerations.

No violations were identified.

5.0 Licensee Reports

5.1 In-Office Review of Licensee Event Reports

The inspector reviewed Unit 1 LERs submitted to the NRC Region I office to verify that details of the event were clearly reported, including the accuracy of description of the cause and adequacy of corrective action. The inspector determined whether further information was required from the licensee, whether generic implications were involved, and whether the event warranted onsite followup. The following LERs were reviewed:

LER Number	Title
85-080 (a)	Supplement 1 - Flood Barriers
85-084 (b)	Failure to Initiate a Manual Rod Block
85-085	Actuation of CREFAS (Chlorine Tape Break)
85-086	Actuation of CREFAS (Chlorine Tape Break)
85-087	Failure to Meet Fire Protection Condition
85-088	Loss of 120 VAC UPS Power to RPS Channel B
85-089	Reactor Enclosure Ventilation Isolation
85-090	Actuation of CREFAS on High Toxic Chemical Alarm
85-091 (c)	Failure to Comply with Primary Containment Isolation Requirements
85-092 (d)	Actuation of CREFAS (Chlorine Tape Break)
85-093 (d)	Actuation of CREFAS (Chlorine Tape Break)
85-094	Toxic Chemical Analyzer Failure
85-095 (e)	Scram Due to High Neutron Flux

NOTES:
a. Addressed in Detail 2.5
b. Addressed in Detail 5.2.2
c. Addressed in Inspection Report 50-352/86-03
d. Addressed in Detail 5.2.1
e. Addressed in Detail 4.2

5.2 Onsite Followup of Licensee Event Reports

For those LERs selected for onsite followup as noted in Detail 5.1, the inspector verified the reporting requirements of 10 CFR 50.73 and Technical Specifications had been met, that appropriate corrective action had been taken, that the event was reviewed by the licensee, and that continued operation of the facility was conducted in accordance with Technical Specification limits.

5.2.1 LER 85-092 and 093; CREFAS Actuations

On December 5, 1985, two instances involving isolation of the main control room ventilation system occurred as a result of broken chlorine detector tapes. Each failure caused automatic initiation of the control room emergency fresh air supply (CREFAS) system, as designed. The reactor was operating at 82% power at the time, and each isolation was reset within 30 minutes. The failure of chlorine detector tapes has been a frequently experienced (and reported) problem, with twelve similar failures having occurred since July 1985 and 17 reportable instances since issuance of a low power license.

The "D" chlorine detector tape broke at 9:10 a.m. on December 5, 1985, causing actuation of the "B" CREFAS train. The tape was replaced, however, a faulty zero adjustment potentiometer was discovered and the isolation signal was bypassed via temporary circuit alteration (TCA)-446. The detector was returned to operability on December 10, 1985. The licensee made the required ENS notification to the NRC at 11:20 a.m. on December 5.

The "C chlorine analyzer tape broke at 3:49 p.m. on December 5, 1985, causing actuation of the "A" CREFAS train. The isolation was reset in 26 minutes and the tape was replaced. Although the "D" chlorine detector was out of service at the time, readings on the two other ("A" and "B") chlorine detectors were observed to show normal levels for control room intake ventilation air. The ENS call to the NRC for the "C" tape break and CREFAS initiation was not made within the required four hours specified in 10 CFR 50.72, and was subsequently made the following day, December 6, 1985, at 2:00 p.m. The call was delayed because of the first instance, which served to confuse supervisory review of notification, as well as plant problems which had developed with turbine shaft differential expansion, generator stator cooling, and main generator isophase bus duct heating. However, the failure to notify the NRC has not been a recurrent problem, and was discovered by shift superintendent review of plant logs and promptly corrected. The inspector therefore concluded that the late report of the second CREFAS initiation was of minimal significance, that the licensee's reporting procedures and performance in this regard were adequate and that no violation was warranted.

The inspector evaluated the licensee's corrective action for the defective chlorine detector design which has resulted in the frequent occurrence of tape breaks and control room ventilation isolations. The inspector reviewed the safety evaluation for modification package (MDCP)-0416, describing replacement of the existing "C" and "D" chlorine channel detectors (MDA Scientific Inc. Model 7040) with a different type of detector (Anacon). The new detector will replace the existing photocell detectors and will improve reliability since they can also differentiate between an equipment malfunction and an actual high chlorine concentration. A new alarm will be provided which indicates an equipment (detector) malfunction. The maximum response time required for the detector is 6 seconds for a change in chlorine concentration of 0 to 5 ppm. The inspector also reviewed the Anacon specifications for the electrochemical probe, and observed installation and "burn-in" of the new detectors. The licensee currently plans to place the new detectors in service by mid-February, 1986. The post-modification testing of the new detectors will be followed in future inspections. The licensee also initiated a Licensing Document Change Notice (LDCN) FS-925 to revise appropriate FSAR sections related to chlorine detection. No unacceptable conditions were noted.

5.2.2 LER 85-084; Failure to Initiate a Manual Rod Block

LER 85-084 described the licensee's discovery on October 14, 1985, of less than the required number of intermediate range neutron monitors (IRMs) operable for purposes of rod block monitoring. The reactor was critical and a plant startup was underway at the time. Four control rods were withdrawn during a 47-minute period before a shift technical advisor (STA) recognized that only five IRMs were operable; one less than the minimum required. Rod withdrawal was immediately suspended until a sixth IRM could be tested and returned to service.

The "C" and "F" IRMs were inoperable and had been bypassed prior to commencing the startup. During the startup, erratic response from the "D" IRM was observed by operators and was eventually placed out of service although normal response had returned. In accordance with reactor protection system (RPS) Technical Specifications regarding inoperability of more than one detector (the "D" and "F" IRMs) in an RPS channel, RPS channel B was placed in the tripped condition with a half-scram signal initiated via the manual scram push buttons. However, operators did not recognize an additional Technical Specification Table 3.3.6-1 for rod block monitoring which required 6 of 8 IRMs to be operable.

The safety significance of this event was minimal in that:

-- A half scram signal was in effect

-- Of the rods withdrawn, three were peripheral and the other was adjacent to an operable IRM and therefore monitored

-- The condition existed for a short time (47 minutes)

-- The "D" IRM was reading normal (although suspect)

-- Both the RSCS and RWM systems were operable and capable of enforcing rod blocks for out-of-sequence withdrawals

The inspector discussed this event with licensed operators who were cognizant of the cause and details presented in LER 85-084. The inspector also verified that a November 7, 1985 Operations Memorandum had been reviewed by shift licensed personnel. The memo emphasized that, when equipment is declared inoperable, there may be more than one Technical Specification action statement which is applicable, such as for inoperable IRM detectors. The inspector noted that the independent review, discovery and communication to shift supervision indicated a strength in the licensee's STA program, particularly with respect to Technical Specifications. The inspector concluded that, given: (1) the minimal safety significance and effective corrective action for the event; (2) the circumstances surrounding its discovery and prompt reporting by the licensee (in LER 85-084); (3) that there have been no previous similar occurrences; and, (4) a violation was not assessed as provided for by the NRC's enforcement policy with respect to self-identified and corrected problems.

The inspector had no further questions.

6.0 Surveillance and Modification Activities

6.1 Surveillance Activities

The inspector observed or reviewed the performance of selected surveillance tests to determine that: the test procedure conformed to technical specification requirements; administrative approvals were obtained before initiating the test; testing was accomplished by qualified personnel in accordance with an approved procedure; test instrumentation was calibrated; Technical Specification limiting conditions for operation were met; test data was accurate and complete; removal and restoration of the affected components were properly accomplished; test results met Technical Specification and procedural requirements; deficiencies noted were reviewed and appropriately resolved; and, the surveillance was completed at the required frequency.

The following surveillance activities were witnessed:

6.1.1 RPS Manual Scram Channel Functional Test

The inspector observed the performance of ST-6-071-307-1, a monthly functional test of the reactor protection system (RPS) B1 and B2 manual scram channels. The test was performed by the reactor operator at main control room console 603 by depressing the manual scram push buttons for RPS channels B1 and B2. The inspector verified that:

-- Proper manual scram logic was satisfied, with no resultant rod motion

-- Proper annunciation occurred for arming and actuating each channel

-- Scram signals were reset

-- Scram pilot valve solenoids properly de-energized and re-energized, as evidenced by indicating lights in the main control room and auxiliary equipment room

-- Adequate independent verification was performed for disarming the manual scram push buttons

The inspector noted that the operator performing the test maintained good communication with personnel stationed in the auxiliary equipment room, and that the operator followed the test procedure, especially regarding the prerequisite for no existing scram signals prior to performing the test.

No unacceptable conditions were identified.

6.1.2 Control Rod Exercise Test

The inspector reviewed LER 85-078 which described a failure to perform surveillance testing for control rods when reactor power is greater than the preset interlocks of the Rod Worth Minimizer (RWM) and Rod Sequence Control (RSCS) Systems. At power levels less than 20%, rod blocks are in effect which prevent performance of ST-6-107-760-1. Above 20% power, the test requires moving all withdrawn rods at least one notch every seven days. The test was not done for the 14-day period from August 23-September 6, 1985, during startup testing at power levels of from 23-30%. Rod operability was however demonstrated by rod movement during startup testing throughout the time in question, as well as subsequently on October 1, 1985, when ST-6-107-760-1 was initially performed.

The cause of the failure to perform the test was the manner in which the test was entered for scheduling in the licensee's computerized surveillance test and records system (STARS). Specifically, the out-of-surveillance report maintained by the test coordinator listed ST-6-107-760 as not done, but the ST was not listed on the weekly schedule provided to shift operations. The test coordinator assumed that the ST was referenced in General Plant Procedure GP-2, Normal Plant Startup, and therefore, the requirement to perform the ST would be identified by operators during plant startup when power reached the 20 percent level.

The inspector reviewed the licensee's corrective actions to preclude missing ST-6-107-760. Step 3.5.12 was added to Startup Procedure GP-2 at the 20% power plateau to verify that ST-6-107-760 is either in surveillance or to perform it above the RWM/RSCS preset power level. A permanent tag, Operations Aid #107-6, was placed on the RWM/RSCS Panel No. 601 in the main control room providing guidance similar to GP-2, Step 3.5.12, on performing the control rod notch testing above 20 percent power. The inspector also reviewed the out-of-surveillance report and discussed the above issue with the ST coordinator. No other STs were identified which had not yet been initially performed (but were required to be) as in the case of ST-6-107-760. The inspector reviewed a memorandum from the Technical Engineer which directed awareness of changing plant conditions as the power ascension test program progressed, and their relation to Technical Specification requirements. The inspector noted that there have been no similarly missed surveillances identified either prior to or subsequent to this event and that ST-6-107-760 had been satisfactorily performed on December 29, 1985, and January 13, 1986.

Based on the above, the inspector concluded that issuance of a violation was not warranted since:

-- Control rods were demonstrated as operable by other means during the fourteen-day period from August 23-September 6, 1985

-- ST-6-107-760 would have been required to be performed only twice during the period in question, and was successfully completed for all withdrawn rods on October 1, 1985

-- The missed ST was identified by the licensee, promptly performed, accurately reported in LER 85-078, and had not been a recurrent problem

-- Corrective actions were thorough and effective in that no similar failures to perform STs have occurred.

The inspector had no further questions.

6.1.3 Drywell Spray Valve MOVAT

On January 7, 1986, the inspector witnessed a Motor Operated Valve Analysis and Test (MOVAT) performed on HV51-1F016A which is the outboard containment isolation valve for Loop A drywell spray. The MOVAT was conducted in accordance with Field Engineering Procedure No. FE-16, Evaluation of As-Found Limitorque Valve Stem Thrust and was requested by local leak rate test (LLRT) personnel. In December 1985, the valve had failed to close properly and had experienced an unacceptably high leak rate in excess of 60,000 standard cubic centimeters per minute (SCCM). The LLRT is addressed in NRC Inspection Report No. 50-352/85-48.

When valve HV51-1F016A was tested in December 1985, an additional 8 manual turns were required to fully close the valve after it was stroked closed from the control room. The results of the January 1986 MOVAT indicated a stem thrust of 18,000 to 22,000 lbs which should have been adequate to close the valve. However, during the performance of the MOVAT, excessive grease was identified in the torque sensing mechanism of the operator which could cause the valve motor operator to stop due to the torque setting prior to full closure of the valve.

The final penetration LLRT leakage, with the valve HV51-1F016A manually isolated, was 372 SCCM. While this leakage rate is an acceptable low value for the penetration, the outboard HV51-1F016A valve was isolated and secured closed in accordance with Technical Specification 3.6.3 for containment isolation purposes. Inboard isolation valve HV51-1F021A was determined to be leak tight prior to the discovery on December 17, 1985, that HV51-1F016A was not fully closed as evidenced by subsequent drywell inspection by the licensee which found no evidence of inleakage at the drywell spray headers. The drywell spray system is not required by Technical Specifications to be operable, however, while Loop A is currently isolated, Loop B is available. The licensee plans to perform repairs on the Limitorque operator for HV51-F016A and retest the valve for leakage during the outage scheduled to begin in April 1986. The inspector had no further questions at this time, although the licensee's evaluation of the cause of the failed LLRT will be addressed in future inspections.

No violations were identified.

6.2 Standby Liquid Control System Modification

The inboard containment isolation valve on reactor water cleanup (RWCU) system closed on December 19, 1985, because of a modification being done on the standby liquid control system (SLCS). The unit was in Operational Condition 2, Startup, at the time and was not yet critical. Technical Specifications require operability of two of the three SLCS pumps, so that one pump may be inoperable at any time. Modification work being performed on the "A" SLCS pump caused an SLCS initiation signal to occur, which isolated RWCU, as designed. The SLCS pump did not start since its motor feeder breaker was not energized because of the modification work. The isolation was reset and RWCU restored within 15 minutes. The licensee reported this event via an ENS call to the NRC at 6:19 p.m. on December 19, 1985.

The inspector reviewed modification package MDCP 85-806. The modification is intended to prevent the type of inadvertent initiation that occurred on December 19. The modification replaced existing SLCS actuation relays in the pump motor control circuits with time-delay pickup relays set for one second. The time delay is sufficient to prevent transient initiation signals from actuating SLCS when power is being restored to the pump motor circuits. The modification was implemented in accordance with General Electric Field Deviation Disposition Request (FDDR) No. HH1-4515 approved on October 25, 1985.

The FDDR described the operation of high power output isolation (HPOI) circuit cards which provide for interface between SLCS and the Redundant Reactivity Control System (RRCS). The HPOI card is powered from the SLCS pump control power. When initially powered up, the HPOI card can pass current or energize a load for up to 150 milliseconds. As occurred on December 19, 1985, energizing the HPOI will seal-in the SLCS control relays C41-K4 and K5 which will activate the SLCS.

The inspector reviewed the safety evaluation associated with MDCP 806 which was reviewed by the PORC at Meeting 85-116 held on November 20, 1985. The PORC concurred in the evaluation's conclusion that no unreviewed safety questions were created as a result of the modification. Also discussed in the evaluation is a separate modification (MDCP-189) that has not yet been implemented but will extend the RRCS time delay for automatic initiation of SLCS from the existing 58 seconds to 118 seconds with two pumps operational and 358 seconds with three pumps operational.

The safety evaluation associated with MDCP-189 concluded that the longer time delays are acceptable, so that the additional one second time delay added by MDCP-806 is also acceptable. MDCP-189 involves a modification to the RRCS software and is not associated with the C41-K4 and K5 pickup relays in the SLCS control logic. Therefore, the MDCP-806 modification is considered as temporary until MDCP-189 is implemented. The 1-second time delay relays will then either be removed, or the evaluation for the 118/358 second RRCS delay will be extended by one more second (and the relays will be left installed).

Since the one second time delay is also in effect when a SLCS pump is manually actuated via the control room hand switch, the licensee attached permanent Operations Aid 48-13 to control room console 603 which guides the operator to hold the SLCS pump control switch in the Run position for one second. The short time delay does not affect the procedure by which an operator manually starts a pump, and proper start is still verified by status indicating lights, so that no procedural changes were made. The inspector reviewed SLCS Technical Specification 3.1.5 and verified that no changes were required as a result of MDCP-806.

The inspector also reviewed the modification acceptance test (MAT) procedure for MDCP-806 which was performed on December 19, 1985, for the "A" SLC pump to verify post-modification operability. The inspector noted that, by performing MDCP-806 on one of three SLC pumps at a time, the SLCS would not be considered in a Technical Specification LCO since only two pumps are required to be operable. Also, testing was begun by de-energizing the reactor water cleanup (RWCU) inboard isolation valve prior to removing the squib injection valve fuses and disabling the "A" pump motor breaker and thermal overloads. The correct order of these test steps ensured that, when the pump motor breaker was closed and energized and the pump was started, an RWCU isolation (which happened earlier on December 19, 1985, during installation of MDCP-806) would not occur. The inspector had no further questions, although a review of the LER describing this event, and corrective actions to preclude similar problems with the installation of modifications, will be followed in a future inspection.

7.0 Startup Testing

7.1 STP-25.3; Full MSIV Isolation

The licensee performed startup test STP-25.3, Full Main Steam Isolation Valve (MSIV) isolation, from 92% power at 7:39 p.m. on December 18, 1985, by manual initiation of a low steam line pressure signal. All MSIVs closed, causing a reactor scram as designed. Reactor vessel water level dropped to a minimum of minus 34 inches, causing an automatic initiation of HPCI, but water level recovered quickly and HPCI did not inject into the vessel. RCIC was manually initiated, since the nominal low level automatic setpoint of minus 38 inches was not reached. The main turbine tripped at 3 minutes after the scram on main generator reverse power/lockout relay actuation. Both recirculation pumps tripped, as designed. Reactor steam pressure reached a maximum of about 1100 psig, however, this was lower than the safety relief valve (SRV) settings and no SRV lifts occurred. Reactor pressure was maintained by HPCI and RCIC, and level by RCIC, until these systems were secured about 1 hour later. All MSIVs were re-opened at 8:24 p.m., 45 minutes after the test was begun. The recirculation pumps were restarted by 8:50 p.m., and plant conditions were stabilized by 9:30 p.m.

The test was witnessed by the resident inspector and two regional specialists. The inspector observed that:

-- all proper test prerequisites and conditions were met

-- plant operations and support staff, including management, were well organized and prepared by virtue of briefing sessions held at 5:00 p.m. and again at 7:00 p.m. just prior to the test

-- clear and concise communications were evident between operators and shift supervision during the test, including delegation of responsibilities for the various stationed panels

-- a timely post-test de-briefing was conducted, with participation by the Station Manager, to ensure accurate test information and evaluation of test results

-- plant management involvement was evident by the presence of the Station Manager, Superintendent of Operations, and the Operations and Technical Engineers during the test

-- test engineers were provided in the control room during the test, available and prepared to address any systems problems or operational/technical difficulties which may have been experienced.

-- the operating shift was well-staffed with extra shift superintendents and SRO - qualified personnel (beyond normal compliments), as well as licensed personnel manning the various control stations at HPCI/RCIC, Recirculation, Feedwater, Electrical and SRV panels

-- Operators effectively used Trip Procedures in plotting and trending post-trip parameters such as reactor level and pressure, and suppression pool temperature

The inspector observed the successful conduct of STP 25.3 in accordance with procedure, and prudent operator intervention in manually controlling pressure and level using HPCI and RCIC during the transient. The inspector reviewed the post-trip sequence of events printout and the alarm type data, and verified proper post-scram conditions. No unacceptable conditions were identified.

7.2 STP-27.4, Main Turbine Trip from Full Power

At 8:54 p.m. on January 2, 1986, the main turbine was tripped with the reactor at 99% power to conduct STP-27.4. A reactor scram occurred due to the turbine trip, and all safety systems performed properly. The test was performed a week earlier than planned, since the unit was required to be shutdown to repair a steam leak, identified on January 2, 1986 (addressed in Detail 4.3) in the cross-around piping area of the main turbine. The location of the leak could not be determined prior to the turbine trip.

7.2.1 Test Results

STP-27.4 required no operator actions for the first three minutes. During this period, the feedwater pumps automatically tripped when reactor water level reached +54 inches, Water level did not reach minus 38 inches and thus no automatic initiations of HPCI or RCIC were demanded. RCIC and HPCI were manually initiated. No SRVs were actuated. Because of the location of the earlier cross-around steam leak, (discussed in Detail 4.3) condenser vacuum was lost approximately 25 minutes after the turbine trip. The loss of vacuum caused the MSIVs and turbine bypass valves to close, and thus the feedwater pumps were unavailable. The test was witnessed by a Region I test specialist. This test is further addressed in NRC Inspection Report No. 50-352/85-48.

The inspector reviewed the turbine trip startup test data sheet and confirmed that all Level I test criteria had been met, including:

-- Initial bypass valve opening time of 0.055 seconds from the beginning of initial turbine stop valve closure, and opened to 80% by 0.240 seconds

-- No flooding of the main steam lines due to proper feedwater control operation

-- 2.46 second average scram insertion time for all operable control rods from fully withdrawn to notch position 05. This time was approximately 30% faster than the required Technical Specification limit of 3.49 seconds

-- Measured time interval difference between auxiliary contact actuation and actual arc suppression of the recirculation pump trip breakers was 107 milliseconds for pump "A" and 98 milliseconds for pump "B"

-- Recirculation pump flow coastdown transient inertia time constant was less than 4.5 seconds from 0.25 to 2.0 seconds following the pump trip

-- Reactor heat flux increase of 0.4% rated and a dome pressure increase of 114 psi, with peaks of 98.7% and 1102 psig

No unacceptable conditions were found and the inspector had no further questions regarding test results.

7.2.2 Offgas Loop Seal Pressure Spike

Due to excessive post-trip condenser air in-leakage because of the ruptured crossover expansion joint, a flow and pressure spike was caused in the Offgas System which allowed untreated air and non-condensible gases to be released to the north stack. The pressure spike was in excess of 5.2 psig at the inlet to the offgas holdup piping, and sufficient to overcome an 11-foot loop seal on the offgas hydrogen analyzer and radiation monitor drains.

A flowpath through ½ inch sample drain piping was established which vented eventually to the north stack and bypassed the offgas system process treatment. The momentary release was observed on a control room recorder at Panel 624 (sample point number 7) for the Recombiner Room and Hydrogen Analyzer Room Ventilation Radiation Monitor. The licensee observed a spike on the recorder channel, determined the release path, and calculated the maximum release rate to be approximately 170 microcuries per second. This release rate is approximately 0.05% of the Technical Specification limit placed upon the discharge of the recombiner after-condenser.

The inspector reviewed a memorandum to all Shift Superintendents dated January 10, 1986, which described the event and a method of isolating the pathway should offgas system pressures increase above 5.2 psig. The licensee is considering a permanent modification to enlarge the loop seal, making it less sensitive to pressure spikes in the offgas system. NRC Inspection Report No. 50-352/86-02 addresses the radiological significance of this event. The licensee's actions in regard to identification and correction for this problem were found to be timely and appropriate. No violations were identified, and the inspector had no further questions.

7.3 Startup Testing: Radiation Surveys

Documents Reviewed

-- Final Safety Analysis Report (FSAR), Chapter 14, "Initial Test Program"

-- Startup Test Procedure STP 2.0, Revision 1, "Radiation Measurements - Main Body", dated September 13, 1984

-- Startup Test Procedure STP 2.1-5, Revision 1, "Startup Radiation Surveys-Prior to Fuel Load", dated October 3, 1985

-- ANSI/ANS-6.3.1, 1980, "Program for Testing Radiation Shields in Light Water Reactors (LWR)"

Review of STP-2.0 and 2.1-5 test data indicated that the licensee was conducting startup radiation surveys in accordance with FSAR commitments and procedures requirements. No unexpected levels of radiation were encountered. The licensee's PORC reviewed the test results on October 16, 1985.

STP-2.0 will be repeated under Test Condition 6 (100% power).

No violations were identified.

7.4 Deletion of STP-1.4 and 30.4 from Startu Test Program

The inspector reviewed a licensee letter dated December 11, 1985 (Daltroff to Butler) to the NRC deleting the performance of Reactor Water Cleanup (RWCU) system performance test STP-1.4 during TC-3 testing and the recirculation pump runbac test STP-30.4. Both tests were deleted because they are demonstrate later during TC-6 testing, and the recirculation pump runback is not taken credit for in FSAR transient analyses.

The inspector reviewed the minutes of PORC Meeting Number 85-107 conducted on November 5, 1985, during which the Committee reviewed safety evaluations in support of the above test deletions. The dynamic water purification capacity of RW J system had been previously demonstrated due to the higher-than-norma hotwell conductivity experienced during September-October 1985 oper. tion at 30-70% reactor power. The safety evaluation found no unreviewed safety questions associated with the deletion of the STP-30.4 recirculation Pump Runback test, or effects upon other testing. The conduct of another test in TC-6, STP-23.5, Feedwater Pump Trip, will demonstrate the recirculation flow runback feature upon coincident loss of one feed pump and a low vessel level.

The inspector reviewed procedures STP-1.4 and 30.4, as well as, RWCU system performance during TC-3. No unacceptable conditions associated with the deletion of the subject tests were identified, and the inspector had no further questions.

8.0 Main Generator Isophase Bus Duct Heating

Reactor power was reduced from 95 to 71% at approximately 7 p.m. on December 5, 1985, following discovery of localized hot spots on the main generator output isophase bus duct. The isophase busses are forced-air cooled and located within 3 foot diameter aluminum ductwork. The duct is constructed in two pieces which are bolted together, electrically insulated and grounded. The hot spots initially found were at two spots, where bolting connects the duct, at approximately 5 feet beneath the main generator. The spots were measured to be about 600 degrees F, and were caused by induced circulating currents in the duct. The problem was abated by reducing generator output to 20,000 amps.

Following the shutdown associated with STP-25.3 (see Detail 7.1) on December 18, the duct was replaced and additional structural steel was added. Power ascension was stopped at approximately 95% and main bus current of 28,000 amps, where a maximum duct temperature of 325-350°F was experienced at a single location on the "B" phase duct. Cooling fans were placed in-service, external to and directed at the hot spot, and the licensee continued to monitor the hot spot temperature through this inspection period. Engineering analyses performed by the licensee have indicated no structural problems at the duct temperatures experienced. The inspector observed the hot spots and the modified bus duct, and discussed this issue with Operations personnel.

No violations were identified.

9.0 Radwaste Transportation Activities

The licensee's transportation program was reviewed with respect to package selection, quality assurance and shipment of radioactive waste. The inspector noted the licensee had made seventeen shipments since November 20, 1985.

9.1 Selection of Packages

The licensee's program for selection of packages was examined against the requirements of 10 CFR 71.12, 10 CFR 71.87 and within the framework of the DOT requirements of 49 CFR Parts 173.

For dry radioactive waste, the licensee used steel drums as strong tight containers. Radioactive material shipments for dewatered resins were made in steel liners or high integrity containers (HIC) which were transported in NRC Certified Casks which were vendor supplied.

Within the scope of this review, the following issues were identified:

The inspector observed an NRC approved package Certificate of Compliance (C of C 9151) labeled as model 14-170 Series I and DOT-7A. The C of C specifies Model Number 14-170 Series I as approved package. However, the DOT-7A labeling is not permitted by C of C 9151 because it implies NRC approval.

The licensee stated that the casks were used as an overpack for the HICs and not used because of the type/quantity of radioactive material. The inspector stated that if the casks were being selected as an overpack to protect the HICs and not being used as an NRC approved package or DOT-7A package, then the labeling that indicates cask approval should be masked during transport.

The inspector noted that the licensee did not have all the documents available as required by C of C 9151, Revision 8. Since the licensee had used the cask as an overpack this oversight was not considered a violation. The inspector stated that the licensee should ensure that all of the requirements of the C of C, including referenced documents relating to maintenance programs and maintenance records are available prior to using the cask as an NRC certified package.

The licensee acknowledged the concerns identified above, and the inspector stated these issues would be considered unresolved (352/85-46-01).

9.2 Shipment of Licensed Material for Disposal

The transportation of licensed material was reviewed against the criteria contained in 10 CFR 71, "Packaging and Transportation of Radioactive Material", 10 CFR 20.311(d)(3), "Transfer for disposal and manifests", and 10 CFR 61.55, "Waste Classification", and 10 CFR 61.56, "Waste Characteristics".

The licensee's performance relative to these criteria was determined by the following:

-- discussions with the Radwaste Consultant, Radwaste Physicist, and Quality Control Site Supervisor;

-- review of all shipping manifests and related documents for shipments made up to December 20, 1985; and

-- review of selected program procedures including the following:

  -- HP-900 "General Requirements for Shipping Radioactive Materials"

  -- WM-014, "Operating Instructions for Loading and Unloading the NUS 14-170 Series I Casks"

  -- RW-101 Radioactive Waste Shipment

  -- HP-715 Vehicle Surveys in support of: Radioactive Material and Radioactive Material Shipments

  -- LGS-QCI-016, Packaging and Shipping Operations

Within the scope of this review, no violations were identified. However, the inspector noted the following concerns:

-- Procedure WM-014 was not reviewed in accordance with Technical Specification 6.8.2. The inspector stated that this procedure must be reviewed prior to use of the cask as an approved NRC package.

-- The inspector noted that the shipping manifests were generally accurate. However, three minor inaccuracies with regard to isotope quantity and volume of waste were identified. In addition, the vehicle survey reports for three shipments were not completed in accordance with HP-715. However, an official record of the survey was available and data complete on forms HP-211 and LGS survey Data Sheet.

The licensee acknowledged the above concerns and the inspector stated that the concerns would be reviewed during a subsequent inspection (352/85-46-02).

9.3 Quality Assurance Program

The implementation of the licensee's Quality Assurance Program (QAP) for transport packages was reviewed against the criteria contained in 10 CFR 71, "Subpart H-Quality Assurance", and 10 CFR 50, Appendix B.

The licensee's performance relative to these criteria was determined from: (1) discussions with the QA auditor who performed the Radwaste and Shipping Audit and the Quality Control Site Supervisor and Quality Control Inspectors; and (2) review of QC monitoring reports for Radwaste Shipping and Handling Activities; QAP-Radioactive Waste/Material Activity Section, Revision 0; and Purchase Orders for NYS Processing Services Corporation.

The inspector noted that the licensee had requested and received Operations (Electric Production) QC inspections for all radioactive waste shipping. An audit had been completed, but was not available for review at the time of this inspection. The adequacy of the licensee's audit program for transport packages will be reviewed when the audit is finalized and reviewd by future NRC inspections.

Within the scope of this review, no violations were identified.

10.0 Leak Rate Test Exemptions

NRR/Licensee Meeting; Limerick Request for Extension

On December 17, 1985, the inspector attended a meeting held at NRC offices in Bethesda, Maryland at which the licensee presented a request for two temporary extensions of required local leak rate testing (LLRT). The extensions are as follows:

-- An extension of fourteen weeks to the surveillance testing interval for the reactor instrumentation line excess flow check valves contained in Technical Specification 4.6.3.4.

-- An extension of up to twelve weeks to the local leak rate test (Type C tests) interval for 37 primary containment isolation valves specified in Technical Specification 4.6.1.2.d and 4.6.1.2.g, as well as an exemption from the requirements of 10 CFR 50, Appendix J, Section III.D.3.

The licensee presented technical justification for the extension in both areas. For the excess flow check valves the licensee performed an industry wide check of the operability record for these valves, to show the confidence they have in requesting the extension. The NRC requested that the licensee include this information in their application for amendment which was subsequently transmitted by letter to the NRC dated December 18, 1985.

The licensee justification for the temporary extension from the type C testing of the 37 containment isolation valves was based on the preoperational test results and also the leak rate experience of isolation valves in industry in general. However, the presentation did not address the particular valves installed at Limerick (i.e., type and manufacturer). The NRC requested that the licensee do a more detailed review to determine if the particular valves in question have been tested at other facilities and the outcome of their leak rate tests. The licensee agreed to present the results of their findings by letter to NRC as additional information. The inspector had no further questions at this time.

The following personnel were present during the December 17, 1985 meeting:

NRC

J. S. Guo, Engineer, Engineering Branch, Division of BWR Licensing, NRR
J. Kudrick, Engineer, Plant Systems Branch, Division of BWR Licensing, NRR
R. Martin, Limerick Project Manager, Division of BWR Licensing, NRR
J. Page, Engineer, Engineering Issues Branch, Division of Safety Review and Oversight, NRR
S. Kucharski, Resident Inspector

PECO

J. Franz, Operations Supervisor
J. Muntz, Test Engineer
J. Nagle, Licensing Engineer

11.0 Unresolved Items

Unresolved items are items about which more information is required to ascertain whether they are acceptable or constitute a deviation or a violation. Unresolved items are discussed in Details 9.1 and 9.2.

12.0 Exit Meeting

The NRC resident inspector discussed the issues and findings in this report throughout the inspection period, and at an exit meeting held with Mr. G. Leitch and others of your staff on January 10, 1986. At this meeting, the licensee's representatives indicated that the items discussed in this report did not involve proprietary information. No written material was provided to the licensee during this period.