U.S. NUCLEAR REGULATORY COMMISSION

Region I

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Licensee:	New York Power Authority
Facility:	James A. FitzPatrick Nuclear Power Plant
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Dates:	July 28, 1996 through September 28, 1996
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EXECUTIVE SUMMARY

James A. FitzPatrick Nuclear Power Plant
NRC Inspection Report No. 50-333/96-06

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report includes the results of routine health physics and effluent control program inspections. In addition, the results of a special team inspection conducted to review the September 16, 1996 reactor scram event are included.

Operations

Overall, the inspectors noted good performance by the operation staff during the inspection period.

- During the performance of 345 KV backfeed transformer ground fault protective relay calibration, two terminals were inadvertently shorted, which tripped the generator output breakers and resulted in a plant scram. Because of the particular relays involved, a residual transfer vice a fast transfer of electrical loads occurred, resulting in the loss of numerous balance of plant loads. The inspectors determined, with the exception of the issues noted below, that the abnormal and emergency procedures used during the event were appropriate and gave the guidance and information needed by the operators and that operators responded well.

- An inadequate procedure to restore the uninterruptible power supply (UPS) bus and a broad scoped protective tag-out impeded the prompt restoration of UPS. Loss of UPS power to some control room indications, the plant paging system and the security computer made communications and plant access difficult. Communication difficulties were managed by utilization of radios. The de-energizing of the reactor protection system (RPS) was an operator error and the misdiagnosis of the plant conditions with regards to the RPS was a training weakness. Additionally, the training operators received for residual transfer events was unrepresentative of the actual plant response.

- The inspectors determined that overall, the PORC appropriately addressed nuclear safety matters related to the September 16th plant scram. Action items required for start-up were satisfactorily resolved, and overall, the startup was performed in a safe and prudent manner.

- The condenser response related to the September 16th event (i.e. the MSIV isolation signal input on low condenser vacuum) remains an unresolved item **(50-333/96006-02)**.

Executive Summary (cont'd)

Maintenance

- The LCO maintenance activity to replace the A LPCI battery was conducted very well with significant efforts to reduce the duration in which the plant was in the LCO. The quality of the maintenance performed and the level of effort devoted to the planning of the job was very good. The inspector did note that the seismic qualification process of the battery cells, via similarity, did not ensure that the component was an exact one-for-one replacement of the previously qualified battery. The inspectors will followup on this issue to determine whether any unqualifiable equipment was installed in the plant **(IFI 50-333/96006-03)**.

- The maintenance staff responded well to the failure of the B EDG to properly sequence during surveillance testing by identifying the cause and taking appropriate corrective actions. Subsequent documentation in LER 96-009 was clear, concise and provided sufficient information on the cause and corrective actions taken and planned for the future.

- The 24V Instrument Battery Replacement maintenance was performed well and had the appropriate engineering, quality assurance and operations involvement.

- Post work testing for the replacement of a capacitor in the HPCI inverter power supply was good and the timeliness of the corrective actions to industry information on inverter failures was adequate.

- The licensee's actions to determine the cause of the continued difficulty over the last six months with manually loading the B and D EDGs during surveillance testing and increasing the testing frequency were appropriate.

- The risk significance of the 345 kV relay maintenance was not recognized during planning or conduct of the work. The technician recognized the plant impact and risk significance of the maintenance, but did not relay this to supervisors or control room staff. The subsequent personnel error resulted in a significant challenge to plant operators and a substantial disruption in plant activities. Contributing causes were improper work request planning, failure to communicate plant risk, and failure to properly protect energized adjacent terminals **(VIO 50-333/96006-01)**.

Engineering

- Troubleshooting associated with the September 16 and 18 failures of the RHR D circuit breaker were adequate, and the corrective actions taken to modify the applicable safety-related circuit breakers were appropriate. However, the inspector considered troubleshooting associated with the May 8, 1996, failure of the RHR D circuit breaker to lack the expected rigor, in that troubleshooting assumed the location of the problem without adequate confirmation. Furthermore, the root cause of a previous failure on May 8, 1996, lacked rigor, and more thorough

troubleshooting, such as confirmation of this root cause, may have located a problem with the 52SM/LS contact 5-6 and prevented the failure of RHR D pump during the September 16, 1996, plant transient.

- The inspector concluded that adequate controls were implemented, following the failure of a TIPS power supply and opening of three containment isolation valves, to ensure compliance with technical specifications (TS) for inoperable containment isolation valves. The licensee is continuing to investigate the failure of the power supply and opening of the isolation valves and as such the issue will remain unresolved pending the results of their design review **(URI 50-333/96006-004).**

- The inspectors reviewed and closed **URI 95-21-02**. The inspector concluded that the engineering staff performed a thorough and detailed root cause investigation of the EQ fuse discrepancies identified to date and developed a comprehensive series of corrective actions to prevent recurrence. However, the inspector determined that since documentation of the environmental qualification of fuses were not in an auditable form, as required by 10 CFR 50.49.j, a violation of NRC requirements occurred. This violation was not cited in accordance with Section VII.B.1 of the NRC Enforcement Manual.

Plant Support

- During the September 16, 1996, event, the implementation of the emergency plan was a sound decision. The event was appropriately classified, timely notifications made, and the TSC and OSC were properly staffed and provided assistance to operators in a timely manner. EP procedures, logs and status boards were in use and no significant EP facility discrepancies were evident. EP radiological activities were well coordinated. Based on surveys and environmental radiation monitoring results, there was no indication of any increased radiation levels associated with the event. Security force members responded in a timely manner to assist with plant communications and vital area access.

- The licensee implemented and maintained excellent radioactive liquid and gaseous effluent control programs, sufficient to protect the public health and safety and the environment. The chemistry staff also demonstrated good knowledge and ability, and effectively implemented effluent controls in accordance with regulatory requirements. Maintenance and attention provided to the station ventilation systems was superior.

- The licensee continues to address previous concerns regarding radiation worker practices and the performance of the radiation protection staff. Training of radiation workers has become a licensee strength. Audits, surveillances and self-assessments of the radiation protection program continue to improve.

TABLE OF CONTENTS

Table of Contents (cont'd)

ATTACHMENTS

Report Details

Summary of Plant Status

The unit operated at 100% power until the September 16, 1996, reactor scram. Following the short forced outage and completion of corrective actions for the event, the plant was critical on September 21 and returned to power on September 23. The plant was operating at 70% power at the end of the inspection period.

I. Operations

O1 Conduct of Operations

O1.1 Generator Load Reject and Plant Trip Overview

On September 16, 1996, the plant was operating at 100% power. The uninterruptible power supply (UPS) motor-generator set was out of service for maintenance and the UPS bus was being supplied from the alternate feed. All emergency core cooling system (ECCS) equipment was operable. Instrument and control (I&C) technicians were replacing a 345 kilo-volt (KV) reverse power relay when at 1:04 p.m., the screwdriver being used by one of the I&C technicians slipped and touched two terminals of a generator ground protection relay. The outgoing power circuit breakers tripped and initiated a generator load reject. Turbine control valves received a fast close signal and turbine bypass valves opened to dump excess steam to the condenser. A reactor scram signal was initiated by the turbine control valves fast closure signal.

By design, the inadvertent operation of the reverse power relay operated additional relays which blocked the fast transfer of plant buses to reserve power. A slower residual transfer occurred and the plant buses saw an interruption of power. The 4KV buses were re-energized from reserve power after bus voltages fell to less than 25% of rated voltage. As a result of the residual transfer, many 4KV loads, including condensate and condensate booster pumps, circulating water pumps, service air compressors and most plant equipment power supplies (600V or lower loads) were automatically tripped off due to the undervoltage condition and had to be manually restored later by operator actions.

The alternate feed breaker to the UPS panel tripped on undervoltage during the residual transfer resulting in a loss of all UPS loads including the page/party (Gaitronics), sound power phones, control room radio base station and some plant telephones, feedwater control and electro-hydraulic control (EHC) control power circuits and some indications on the full core display.

When the voltage on the two emergency 4KV buses fell below 62% for 2.4 seconds, the four emergency diesel generators (EDGs) started as required. By the time the EDGs reached rated speed and voltage, the residual transfer had restored power to the two emergency buses; thus the EDG output breakers did not close.

The generator trip caused the control valves to close rapidly and the bypass valves to open. Reactor pressure increased to 1082 psig at 4 seconds after the trip, during which the "G" safety relief valve (SRV) cycled open for a few seconds. Reactor water level decreased as a result of the scram and turbine feed pump trip resulting in both the high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) automatically initiating. Reactor water level reached its lowest recorded level of 126 inches versus a normal operating level of 201.5 inches. Reactor pressure vessel (RPV) level was restored and maintained using HPCI and RCIC pumps. For the duration of the transient, pressure was controlled using HPCI, RCIC and manual operation of the SRVs.

With the initial loss of the electrical busses, the main circulating water pumps were de-energized. This resulted in the loss of condenser heat removal capability and condenser inlet water temperatures reached 225 degrees F because of continued heat addition from cascading steam and feedwater from the feedwater heating system. Condenser back pressure increased until pressure increased above a point at which one of the low pressure turbine rupture discs and reactor feed pump rupture discs ruptured. The discs ruptured approximately 9 minutes after the reactor scram (about 1:13 p.m.). Electrical power was restored to the electrical buses and loads were restored beginning approximately 1:19 p.m.. At 1:40 p.m. a notification of unusual event was declared and the technical support center (TSC) and operational support center (OSC) were activated.

After the rupture discs were repaired and condenser integrity was restored, main condenser heat removal capability was verified, and NYPA exited the emergency plan. Normal shutdown cooling was established at 5:44 a.m. on September 20.

a. Inspection Scope

The inspector reviewed the overall event to determine if the plant response was bounded by the Final Safety Analysis Report (FSAR). The inspector reviewed the transient analysis and discussed the event with plant management personnel.

b. Observations and Findings

The transient is described in FSAR Section 14.5.2.1, Control Valve Fast Closure - Generator Load Rejection. The analysis described the plant response with bypass valves available. Because of the residual bus transfer, the electro-hydraulic control (EHC) pumps were de-energized and bypass valve (BPV) operation could not be sustained long-term. This, however, did not impair the ability to reduce reactor pressure through the BPV and the safety relief valve (SRV) operation; the reactor operators maintained reactor pressure vessel (RPV) pressure and level control using the high pressure emergency core cooling systems. The inspector determined that the temporary loss of off-site power did not impact the ability for emergency core cooling systems to operate and fulfill their safety function.

The condenser response was evaluated against the FSAR descriptions. FSAR section 7.11.2 states that "the condenser protection rupture disc is set at 5 psig...

Because of the closure of the main steam isolation valves (MSIVs) on low condenser vacuum, there will be no actuation of the rupture disc." The section continues with "However, in the unlikely event the rupture disc should rupture, the resultant doses would not exceed those resulting from the steam line break inside the turbine building as discussed in FSAR chapter 14." The licensee stated that Section 7.11.2 of the FSAR does not consider all conditions. The low condenser vacuum closure of the MSIVs is bypassed when the reactor mode switch is not in Run and the turbine stop valves are closed. By procedure, operators place the mode switch in the Shutdown position after a reactor scram which bypasses the low condenser vacuum MSIV closure signal. The licensee is continuing to evaluate the condenser response related to this event in conjunction with General Electric. The NRC plans to review the results of their evaluation.

c. Conclusions

The condenser response related to this event (i.e. the MSIV isolation signal input on low condenser vacuum) is unresolved item **(50-333/96006-02).**

O1.2 Startup Observations

a. Inspection Scope (71707)

The inspectors observed portions of the reactor startup conducted from September 21 to 23.

b. Observations and Findings

The startup was characterized by clear operator communications and procedure use, attentive management oversight, and effective control by shift supervision. Shift turnovers were performed in a controlled manner and crew briefings were good.

c. Conclusions

The overall startup was performed in a safe and prudent manner.

O2 Operational Status of Facilities and Equipment

O2.1 Engineered Safety Feature (ESF) System Walkdowns (71707)

The inspectors used Inspection Procedure 71707 to walk down accessible portions of the following ESF systems:

- RHR Service Water System
- LPCI Battery
- Emergency Service Water System
- Emergency Diesel Generator

Equipment operability, material condition, and housekeeping were acceptable in all cases.

O3 Operations Procedures and Documentation

O3.1 Procedure Adequacy

a. Inspection Scope

The inspector reviewed the abnormal and emergency operating procedures (AOP and EOP) listed in Attachment 2 to determine the adequacy of the guidance given to the control room staff.

b. Observations and Findings

The inspector determined that the abnormal and emergency operating procedures gave appropriate guidance overall to the operators throughout the event. Specifically, AOP-21, Loss of UPS, directed operators to verify the reactor shutdown using back-panel indication because the front panel indications were de-energized. The AOP also listed equipment and indications that were affected by the UPS loss. AOP-1, Reactor Scram, and EOP-2, Reactor Pressure Vessel Control, sufficiently directed operator actions for stabilizing the plant and maintaining RPV pressure and level control.

The inspector identified that the AOPs and EOPs did not direct operators to shut the main steam isolation valves (MSIVs) in the event of a complete loss of vacuum. The MSIVs automatically shut when main condenser vacuum reaches 8 inches (hg), but the trip is bypassed when the reactor mode switch is not in RUN and the turbine stop valves are shut. Operations management addressed this issue by initiating a revision to the AOP-1, Reactor Scram and AOP-31, Loss of Condenser Vacuum, procedures.

The senior licensed operator performing the Post Transient Evaluation identified that AOP-57, Recovery from Residual Bus Transfer, stated that an MSIV Group 1 isolation was an automatic action. This action, however, was not the case and the procedure was corrected. The inspector noted that these procedure deficiencies did not negatively impact the operators performance during the event.

c. Conclusions

The inspector determined that the abnormal and emergency procedures used during the event were adequate and gave the appropriate guidance and information needed by the operators.

O4 Operator Knowledge and Performance

O4.1 Operator Performance

a. Inspection Scope

The inspector reviewed overall operator performance during the event, including scram verification, RPV pressure and level control, actions taken to cooldown the RPV and restore the main condenser. The inspector reviewed operating logs, procedures, and discussed the operator's actions with licensee management and personnel.

b. Observations and Findings

The control room operators responded well to the event performing the appropriate actions as directed in the abnormal and emergency operating procedures to mitigate the transient. The operators used alternate methods of verifying the reactor was shutdown since the normal control panel indications were de-energized by the loss of the UPS. Operators manually verified that all scram valves were open locally at the hydraulic control units, to assure all control rods were fully inserted and later confirmed that all control rods were fully inserted when power was restored to the UPS.

A reactor operator effectively maintained level and pressure control of the RPV using the high pressure coolant injection (HPCI) and reactor core injection cooling (RCIC) systems and the safety relief valves (SRVs) to stabilize and cooldown the reactor. The operators maintained an 80 degree cooldown rate using the above mentioned systems until the condenser was returned to service and the cooldown was completed using bypass valves. Pressure and temperature limits were not exceeded throughout this evolution.

The operators responded appropriately to the complete loss of condenser vacuum. Due to the temporary loss of off-site power, all major plant systems were de-energized. The operators did not immediately restart the circulating water pumps to restore condenser vacuum because of the need to restart service water, compressed air, and other systems necessary to support the circulating water system and plant cooldown in accordance with the AOPs.

The control room operators restarted the circulating water pumps about seven hours into the event after the rupture disks were repaired and established a condenser vacuum after 13 hours. The operators then completed the RPV cooldown using bypass valves to the main condenser. The inspector determined that these actions were appropriate and within the guidance of plant operating procedures.

c. Conclusions

In generally, the control room operators responded well to the event. Operators immediately verified the reactor shutdown, stabilized pressure and level, and cooled

down the RPV in a controlled manner. Control room supervision methodically restored plant systems to enable repair of the main condenser rupture disc and re-establish condenser vacuum to complete the plant cooldown. An exception to the otherwise good performance was the operator actions taken to de-energize the reactor protection system (RPS) bus (see section O4.3). However, a performance issue related to securing the reactor protection system is discussed in Section 4.3 of the report.

O4.2 Uninterruptible Power Supply (UPS) MG Set Recovery

a. Inspection Scope (93702)

During the residual transfer of the plant electrical buses, the alternate feed breaker to the UPS panel tripped on under voltage and by design did not reclose following the transfer. This resulted in a loss of all UPS loads, including plant internal communications (Gaitronics), feedwater control, high range effluent radiation monitors, security computer, and various control room indications. The breaker was manually closed by the operators 1 hour and thirteen minutes following the plant trip. The inspector conducted interviews, reviewed plant drawings and procedures to determine if the power supply was restored in a timely manner and the impact on the restoration of the plant.

b. Observations and Findings

The UPS provides power to vital low voltage loads and utilizes a double motor generator set (AC & DC motor) as the power source. The AC motor is powered from the vital bus and the DC motor is powered from the battery. Under normal circumstances the UPS transfers from the AC power source to the DC power source upon loss of voltage to the vital bus. However, on September 12, the UPS MG set had been removed for corrective maintenance to repair a bad motor bearing and was not available during the transient. The UPS loads at that time were placed on the alternate feeder breaker which provides power via the 12500 emergency bus.

The alternate feeder breaker is a unique low voltage molded case circuit breaker in that it has an electric motor operating mechanism on the front of the breaker. When the operators responded to the tripped UPS panel in the electric bay, they noted that the alternate feeder breaker was "flagged" in the on position. Walk down of the power supply to the UPS distribution panel by the operators determined that the circuit had power. After getting permission from the control room, the electrical supervisor opened the breaker operating mechanism door to observe the position of the handle on the actual alternate power breaker. He discovered that the breaker was indeed tripped open. The original diagnosis that the breaker was closed was the result of the operating mechanism flag not repositioning when the breaker trips on under voltage. Using appropriate electrical safety precautions the electricians attempted to reset and manually close the breaker. When the attempt was unsuccessful, the electricians stopped and reviewed the circuitry for any problems. Subsequently a senior reactor operator returned to the panel, and was able to reset the breaker manually, thereby resetting the UPS bus.

The inspector reviewed the plant drawings and determined that control power was available to the alternate feeder breaker following the residual transfer. However, because of the paralleling switch on the UPS panel being protective tagged in the off position for maintenance, the operators could not have closed the breaker electrically without first clearing the protective tag. This tagout represented a conservative personnel and equipment protection boundary; the delay posed by this tagout had no significant effect on the overall outcome of this plant event. Additionally the inspector determined that the abnormal operating procedure AOP-21, Loss Of UPS, would not have properly directed the restoration of the alternate feeder breaker. The electrical operation of the breaker is such that the under voltage coil opens the breaker and the motor operator functions to reset the breaker so that it is ready to close automatically or when the operating switch at the UPS panel is taken to the close position. The AOP did not have procedural guidance for resetting the alternate feeder breaker and therefore would not have allowed electrical closure of the breaker. The AOP did give subsequent guidance on manually closing the breaker; however, it did not give guidance on removing the operating mechanism and operation of the molded case circuit breaker. As a result, the licensee elected to revise the procedure and conduct training with operations personnel on the UPS alternate feed breaker. Additionally, the work control center is taking steps to ensure the ability to operate the UPS paralleling switch is not significantly impeded during future protective tag-outs.

c. Conclusions

The inspector concluded that the absence of clear direction on the manual operation of the UPS feeder breaker in the AOP and a tagout delayed the licensee in restoring the UPS. This delay had no measurable impact on the outcome of this plant event. The loss of the plant page and security computer made communications and plant access difficult, but were managed by utilization of radios and posting security guards.

O4.3 De-energizing of the Reactor Protection System (RPS) Electrical Buses

a. Inspection Scope (93702)

The inspector conducted interviews and reviewed plant drawings and procedures to determine the issues concerning the RPS power supply restoration during the September 16 event. The impact on the restoration of the plant was also assessed.

b. Observations and Findings

Following the generator load reject and subsequent scram, the shift manager (SM) ordered a shift of the RPS to the alternate power supply. This was done by the SM because he interpreted the dark full core display and the radiation monitor annunciators alarming to be indicative of a loss of power to the RPS. RPS was shifted to a deenergized bus which resulted in the MSIVs closing.

The operator tasked with transferring the power supplies failed to question the fact that the white "MG-SET" light above the RPS power selector switch and the darkened "TRANS" light meant that the system was energized and that the alternate power supply was not. The inspector determined through walkdowns and review of operating procedure OP-18, Reactor Protection System, that the procedure had sufficient guidance to properly shift RPS. However, because of the number of activities and distractions present, the operator improperly transferred RPS.

Through interviews, the inspector learned that the operators were of the impression that if the full core display was dark, that the RPS was de-energized. In addition the operators felt that the numerous radiation monitor annunciators were also indicative of a loss of RPS. The full core display is only partially powered from the RPS bus, with additional power coming from the UPS and non vital buses. The inspector determined, through review of plant drawings and procedures, that the loss of the UPS bus would cause a similar alarming annunciator board, with respect to radiation monitors, as a loss of RPS.

c. Conclusions

The inspector concluded that the de-energizing of the RPS was an operator error and that the misdiagnosis of the plant conditions with regards to the RPS was a training weakness.

O5 Operator Training and Qualification

a. Inspection Scope

The inspector reviewed simulator training regarding residual bus transfers and discussed this issue with the training staff and operations personnel.

b. Observations and Findings

Control room operators informed the inspector that they had believed that the reactor protection system (RPS) bus was de-energized during the event. This was partially due to their training experience at the plant specific simulator and due to confusion regarding the power supplies for the full core display.

The simulator can not replicate a residual bus transfer because the computer is not modeled for this type of transient. To accomplish the effects of the scenario, training instructors insert manual overrides to create the transient affecting simulator fidelity with the plant. The RPS was always de-energized during the training scenario.

The control rod Full-in and Full-out as well as other light indications on the full core display are powered from the UPS power supply. During the event, the operators became confused as to the power supply that fed the full core display, and

operators believed that the RPS power supply was de-energized. Operation management determined that the operator's training was deficient in this area.

The Plant Operations Review Committee (PORC) discussed this issue during their final review of the post transient evaluation. The PORC tasked the training staff to identify other scenarios that had simulator fidelity issues which could result in negative training prior to start-up. Four training scenarios were ultimately identified; these scenarios will not be used until modified and revalidated. Further, Operations management conducted training sessions for the operators regarding the power supplies for the full core display and other control room indications prior to startup.

c. Conclusions

The inspector concluded that the training operators received for residual transfer events was unrepresentative of the actual plant response. The PORC initiated a corrective action item for the simulator staff to identify other faulty training scenarios. Operations management reviewed these negative indications with the operations staff prior to re-starting the reactor.

O6 Operations Organization and Administration

O6.1 Plant Operations Review Committee

a. Inspection Scope

The inspector observed the Plant Operations Review Committee's (PORC) final review of the Post Transient Evaluation and of I&C's root cause assessment into the cause of the event.

b. Observations and Findings

The PORC concluded that there were no unresolved safety questions associated with this event. PORC discussed the event, station personnel performance, equipment performance, corrective actions required and lessons learned. These discussions were open and candid. The PORC chairman emphasized the importance of managers to communicate expectations to the plant staff, the importance of possessing a questioning attitude when unexpected results occur and of self-checking to preclude mistakes caused by over-confidence. The chairman identified several other follow-up issues required to be completed prior to startup that were subsequently resolved by the PORC.

c. Conclusions

The inspector determined that overall, the PORC adequately addressed matters related to nuclear safety. Action items required for start-up were resolved to the satisfaction of the PORC. The most significant items were independently reviewed by the resident inspectors, including the conduct of training for operators and administrative control of the TIP system.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62703)

The inspectors observed all or portions of the following work activities:

- WR 95-07873 replacement of 24VDC instrument battery
- WR 96-02875 calibrate 71-59N-1UPRN05 transformer ground fault protective relay
- WR 96-01045 installation of alternate decay heat removal system per modification FI-95-121
- WR 96-04591 EDG droop circuit
- WR 96-04790 TIP system malfunction
- WR 96-04877 turbine exhaust rupture disk

b. Observations and Findings

The inspectors found the work performed under these activities to be technically sound and thorough. All work observed was performed with the work package present and in active use. Technicians were experienced and knowledgeable of their assigned task. The inspectors frequently observed supervisors and system engineers monitoring job progress, and quality control personnel were present whenever required by procedure. When applicable, appropriate radiation control measures were in place.

M1.2 Surveillance Observations

The inspectors observed and reviewed portions of ongoing and completed surveillance tests to assess performance in accordance with approved procedures and Limiting Conditions for Operation, removal and restoration of equipment, and deficiency review and resolution. The following tests were reviewed:

- ST-2X RHR service water flow rate, strainer and inservice test
- ST-35A Containment spray/cooling system logic system functional test
- ST-9B EDG full load test and ESW pump operability test

b. Observations and Findings

The licensee conducted the above surveillance appropriately and in accordance with procedural and administrative requirements. Good coordination and communication were observed during performance of the surveillance.

M1.3 Conclusions on Conduct of Maintenance

Overall, maintenance and surveillance activities were well conducted, with good adherence to both administrative and maintenance procedures.

M1.4 On-Line Maintenance

M1.4.1 24V Instrument Battery Replacement

a. Inspection Scope (62703)

During this inspection period, the licensee changed out the two sets of instrument batteries as the result of a seismic qualification user's group recommendation for other batteries at the plant. The inspector observed the maintenance activities and reviewed the acceptance testing documentation to verify that the work had been done in accordance with station procedures and industry practices.

b. Observations and Findings

The two instrument batteries are made up of two sets of twelve individual cells. The replacement cells for each battery was a C&D Power Systems model KCR-7 battery, classified as QA category I and having seismic design and installation requirements. Each redundant battery pair provides backup power during loss of off site power or loss of power to its associated battery charger for two SRM/IRM trip units, and several process radiation monitors in the plant. The replacement was performed with the plant operating and the work was performed in a manner that maintained the battery available for service and fully operable. The battery was maintained operable by bringing fully charged spare cells on a portable cart into the battery room and connecting the spare cells in parallel with the cells being replaced. After the new cells were in place and connected to the bus, the parallel connections to the spare cells were broke and the sequence was repeated for the other sets of cells.

The battery work was performed in accordance with maintenance procedure MP-57.06, Battery Maintenance, Revision 16. The evolution was controlled by a temporary operating procedure TOP-234, 24 VDC Instrument Battery Replacement With Reactor In Run Mode, which sequenced the replacement of the batteries.

The inspectors observed the proper procedures and work control documents in use. Maintenance personnel had established and implemented appropriate ignition, fire prevention and personnel safety controls. The maintenance was performed well, with the mechanics being very thorough with moving, assembling and testing the cells.

The inspector noted that the acceptance criteria for the post installation resistance readings in the maintenance procedure was not in accordance with IEEE Standard 484-1987, Recommended Practice for Installation Design and Installation of Large Lead Storage Batteries for Generating Stations and Substations. The maintenance

procedure had an acceptance criteria of less than 60 microhms. The IEEE standard includes direction to remake and remeasure any connection that has a resistance measurement more than 10% or 5 micro ohms, whichever is greater, over the average of each type of connector. Subsequent to this, the licensee reviewed the data and determined that three connections did not meet this IEEE criterion. Their evaluation determine that although the resistance values did not meet this criterion, the resistance readings were lower than the previous readings and thus acceptable. This was also the case for one connection on the initial installation of the A station battery in 1995. The licensee subsequently changed the procedure to reflect the connection resistance readings requirements for new battery installations in the procedure.

c. Conclusions

The inspector concluded that the maintenance was performed well and had the appropriate engineering, quality assurance and operations involvement. The licensee did not incorporate the complete acceptance standard for battery resistance readings in the maintenance procedure. This reflected a lack of thoroughness in the preparation of the procedure. Subsequently, this error in the procedure was adequately addressed.

M1.4.2 LPCI MOV Battery Power Supply Replacement

a. Inspection Scope (62703)

The inspector reviewed the preparation for and conduct of the replacement of the A low pressure coolant injection (LPCI) motor operated valve (MOV) independent power supply battery during a limiting condition for operation (LCO) maintenance evolution. The inspector reviewed the physical condition of the installed replacement battery, commercial grade dedication documentation for the battery, the LCO preparation checklist, portions of maintenance procedures (MP)-057.06, Revision 17, "Battery Maintenance", which was performed as part of the post-maintenance testing on the battery, and MST-71.11, Revision 8, governing quarterly surveillance testing on the battery.

b. Observations and Findings

This LCO maintenance activity was thoroughly evaluated prior to its conduct and was approved based on its minimal potential safety implications to the plant. The LCO maintenance evolution was well planned, supported and controlled as evidenced by the successful completion of the evolution in just under two days, versus nearly 3.5 days as originally planned. The job was worked on a 24-hour basis and considerable efforts were made by the assigned LCO coordinator and other key individuals involved to minimize the duration the battery was out of service as well as resolve emergent concerns. The quality of the installation work was very good.

The inspector identified that the battery was dedicated for seismic application via similarity to a previously qualified battery (i.e. the battery cell size and model number were the same as battery cells previously procured under a 10 CFR 50 Appendix B program and seismically qualified by the manufacturer). However, discussions with the battery manufacturer confirmed that there was recent changes to the battery design (i.e. material changes to the battery cap to improve impact resistance, terminal post seal changes) which raised the question whether the new battery cells were an exact one-for-one replacement. Subsequent engineering analysis of the design modifications confirmed that the design changes to the battery enhanced vice detracted from the seismic qualification of the battery. DER 96-971 was written to characterize and remedy the procurement process deficiency identified in this matter.

c. Conclusions

The LCO maintenance activity to replace the A LPCI battery was conducted very well with significant efforts to reduce the duration in which the plant was in the LCO. The quality of the maintenance performed and the level of effort devoted to the planning of the job was very good. The inspector did note that the seismic qualification process of commercial grade equipment, such as the battery cells, via similarity, did not ensure that the component was an exact one-for-one replacement of a previously qualified component. The inspectors will followup on the findings of DER 96-971 to determine the extent of this issue and whether any equipment that is not seismically qualifiable was installed in the plant **(IFI 50-333/96006-03)**.

M1.4.3 Failure of B EDG to Start During Surveillance Testing

a. Inspection Scope (62703)

The inspector reviewed the reasons and corrective actions taken for a failure of the B emergency diesel generator start sequence during surveillance testing on July 22. Including a detailed review of wiring schematics, plant procedures, EDG operating manual, and subsequently the licensee event report (LER 96-009) submitted on August 22.

b. Observations and Findings

Operations personnel made proper log and TS action statement entries, documenting the situation after the B EDG was declared inoperable. Following the test failure, operations and instrument and control (I&C) personnel took good actions to review the possible causes, including discussions with personnel in the switchgear room. This led to the determination that the reverse power relay had energized, and that it happened before the assumed 3.5 second time delay.

Troubleshooting effectively determined that an incorrectly installed time delay relay and a failed motor on the D EDG governor booster pump, resulted in the tripping of the EDG. The observation that the reverse power relay had energize too early led the licensee, through electrical prints, to determine that the voltage sensing time

delay relay which energizes the reverse power relay had not been installed in the correct location. In effect this led to a time delay being set at 0.8 sec from the designed 3.5 sec. However, the licensee was presented with a problem since this relay had been installed in this configuration in 1990 and the EDG had started successfully during monthly surveillance testing, except for one instance in 1992 when the D EDG governor booster pump was found failed. Subsequent troubleshooting found that the D EDG governor booster pump had failed in this instance as well.

NYPA identified that two other relays had been incorrectly installed during 1990. The inspector found that the two additional incorrectly installed relays would not have affected any other safety related functions of the EDG control circuits.

c. Conclusions

Surveillance testing properly identified equipment conditions which led to the B EDG not properly sequencing during a surveillance test start. The failure of the B EDG to properly sequence resulted from an incorrectly installed time delay relay in the reverse power sensing circuit and the failure of the D EDG governor booster pump. NYPA did not identify the incorrect installation of the time delay relay in 1992 when a similar failure occurred. However, the surveillance tests conducted since then proved that the EDG would have performed its design function. NYPA responded well to the failure, identified the causes and took appropriate corrective actions. Subsequent documentation in LER 96-009 was clear, concise and provided sufficient information on the cause and corrective actions taken and planned for the future.

M1.4.4 HPCI Inverter Failure

a. Inspection Scope (62703)

On September 6, the HPCI inverter failed. The licensee performed trouble shooting and determined the cause to be the failure of a capacitor inside the inverter. The inspector reviewed the post work testing documentation for the replacement capacitor and discussed the activities with the maintenance staff.

b. Observations and Findings

The inspector reviewed the equipment vendor manual and compared the manufacturers information with the post work test data and found it to be satisfactory. The inspector also reviewed the licensee's response to NRC and industry information on failed inverters as documented in the licensee's SOER 83-03. The inspector determined that the licensee had originally evaluated the industry information in 1984. The issue was reviewed again by the licensee in 1992 and in 1993 additional corrective actions were incorporated into the licensee's tracking program. The past corrective actions by the licensee included incorporation of electrolytic capacitor testing and/or replacement in a preventative maintenance program for the inverters. As this recent failure was an oil filled capacitor, it was

not included in the preventive maintenance program. The licensee plans on replacing the oil filled capacitors in the HPCI and RCIC power supply inverters in the next refueling outage.

c. Conclusions

The inspector concluded that the corrective actions were appropriate and that the inverter failure rates was low. The inspector determined that the post work testing and the timeliness of the corrective actions to be adequate.

M1.4.5 Failure of EDGs to Load Properly

a. Inspection Scope (62703)

On March 15, when attempting to performing ST-9B, EDG Full Load Test and ESW Pump Operability Test, the D EDG load started to increase more than the operator expected. Trouble shooting by the license at that time failed to identify any problems, however the droop circuit was suspect. On August 23, and September 9, the problem reappeared on the D and B EDGs respectively. The inspectors reviewed the events to assess the maintenance troubleshooting activities and operability of the EDGs.

b. Observations and Findings

During both recent events after several manipulations of the governor speed control switch, the operator determined the performance of the EDG was improper and opened the output breaker. The B and D EDGs were declared inoperable and the applicable LCO was entered. Trouble shooting was performed with strip chart recorders and instrumentation installed. The licensee was not able to identify the problem, but changed out the droop switches on both the B and D EDGs. The licensee had similar problems back in the 1977 time frame with the A EDG and problems with the B EDG in the 1980 time frame. The droop switches were replaced at that time and the problems did not reappear until this year.

In discussion with the licensee engineering staff, the inspector learned that the droop switch is utilized only during surveillance testing when the operators are manually connecting the EDG to a live bus. With the switch in the normal position, the EDG load circuit is such that it senses load and automatically increases speed to pick up the electrical load as the safety related equipment starts. This feature is undesirable during surveillance testing because the bus is already loaded and connected to the main grid at 60 hertz. With the switch in normal, following synchronization, the EDG would try to take all the load and would overload. The droop circuit does the opposite. In the droop mode, when the EDG senses load, it slows down the EDG and therefore does not assume any load. At this point, the operator uses the speed adjust control switch to load the EDG to the required ST value.

The licensee plans on continuing the monitoring of the EDGs with additional instrumentation during the increased surveillance testing and to change out the droop switches on the A and C EDGs. The licensee also plans on performing an equipment failure evaluation on the removed switch to attempt to determine if contact oxidation was a factor in the problem.

c. Conclusions

The inspector concluded the licensee's actions to determine the cause of the continued difficulty with loading the EDGs during surveillance testing were appropriate.

M1.4.6 345 KV Relay Calibration

a. Inspection Scope (62703)

During the performance of a 345 kV relay calibration, two terminals were inadvertently shorted, which tripped the main generator output breakers. This resulted in a main turbine trip and reactor scram as a result of the electrical load loss (see section 01.1). The inspector reviewed the maintenance task chronology, work package, maintenance and administrative procedures, department written critique, and discussed the event with the maintenance supervisor.

b. Observations and Findings

The scope of the work request was to remove the relay from service, remove the external capacitor from the panel, calibrate the relay, reinstall the capacitor and return the relay to service. A pre-job brief was conducted in accordance with ICSO-20, Instrument and Controls Pre-job Briefing. During the performance of the relay and capacitor removal, the technician identified that the capacitor leads would have to be disconnected from the terminal board area on the relay case instead of the capacitor. This was not expected and is significant because the original work scope encompassed a work area that was electrically separate from the operating plant. As discussed in section E8.1 of this report, the relay is utilized when the plant is shutdown and is electrically separate during normal plant operation. Working near the terminal board area had the potential to, and in this case did, actuate the protective feature of the relay causing the plant trip. Additionally, the technician failed to electrically insulate the adjacent terminals prior to commencing the work.

As identified in the licensee's critique, the work package planning process, conducted on June 6, for the relay calibration did not include a review of the physical location and arrangement of the capacitor. Administrative Procedure (AP) 10.03, Work Package Planning, step 8.1.5 states, in part, to perform a walkdown of the work site to obtain an understanding of the specific needs and location of the work environment. Failure to adequately walkdown the work associated with WR 96-02875-00, to perform calibration of 71-59N-1UPRN05, was not performed with adequate detail to identify the high risk involved with performing the maintenance with the plant at power.

The job scope required the removal of a capacitor from the back of the relay case. When faced with disconnecting the capacitor at the terminals, the technician did not stop the task. The technician recognized the plant impact if terminals 1 and 2 were contacted but did not relay this to his supervisors or control room operators. Administrative Procedure AP-10.01, Problem Identification and Work Control, step 8.5.7 states, in part, that personnel encountering unanticipated problems while performing activities should stop work and notify department supervision. However during the calibration of 71-59N-1UPRN05, when the technician discovered the capacitor had soldered leads instead of mechanical fasteners, as expected, he failed to notify his department supervision. In addition, Instrument Maintenance Procedure IMP-G20, Generic Troubleshooting and Maintenance Procedure, referenced in the work request, states, in part, that prior to disconnecting wires, ensure any adverse affects on plant equipment operation or operational status has been discussed with applicable control room operator(s) and shift manager. However, during the calibration of the relay, when the technician determined that the work had the potential to adversely affect the operation of the plant, he failed to notify control room operators, the shift manager, or his department supervision.

c. Conclusions

The risk significance of this maintenance was not recognized by the licensee during the work planning. When the risk was recognized, it was not communicated to the control room operators or maintenance supervisor. The inspectors concluded that the event was the result of improper work request planning, failure to communicate plant risk, and failure to properly protect energized adjacent terminals. Inadequate walkdown during the planning process and the failure to communicate the risk on the plant to control room operators constituted a procedure violation **(VIO 50-333/96006-01)**.

III. Engineering

E8 Miscellaneous Engineering issues (37551)

E8.1 Review of the Residual Bus Transfer during the September 16 Plant Transient

a. Inspection Scope

The inspector reviewed the electrical distribution bus transfer that resulted from the technician's error on September 16, 1996. Additionally, the inspector reviewed the design basis of the residual bus transfer as described in the Final Safety Analysis Report (FSAR), the FitzPatrick Design bases Document (DBD), and station drawings to verify that the system operated as designed.

b. Observations and Findings

As described in the FSAR, the automatic residual transfer takes place either after an unsuccessful fast transfer, or when the nature of the disturbance will not allow a

fast transfer. Residual transfer is delayed until the voltage on the affected bus has decayed to approximately 25% of the normal, allowing re-energizing of the buses without equipment damage.

The relay that the technician was calibrating, 59N-IUPRN05, provides ground fault protection for the 24 kilo-volt (kV) isolated phase bus duct during the 345 kV backfeed operation. During at power operation this relay is not connected to the system since ground protection is provided by other relays on the output of the generator. The inspector independently verified that reported technician's error would have simulated actuation of Relay 59N-IUPR05, and that the relay actuation would result in a residual bus transfer. Additionally, the inspector verified that the residual transfer operated as design.

During a review of the FitzPatrick design basis document (DBD) for the electrical distribution system, the inspector identified that the actuation of Relay N59-IUPRN05 was not included in Section 4.0, "System Interfaces/Boundaries, Interlocks, and Actuations," for the affected circuit breakers, even though the relay was installed at the time the DBD was developed. However, the installation of the relay was described in Section 8.38 of the Electrical Distribution System DBD, as part of the system history of modifications. Although the DBD is not a required document, it is used by the licensee for informational purposes. The licensee intends to revise the electrical distribution system DBD Section 4.0 to included Relay N59-IUPRN05 as tracked by ACTS Item 22509.

c. Conclusions

The inspectors determined that the reported technician error would have simulated the actuation of the Relay 59N-IUPR05, which resulted in the residual bus transfer. Additionally, the inspector verified that the residual transfer operated as designed.

E8.2 Failure of the D Residual Heat Removal Pump Circuit Breaker During Torus Water Cooling

a. Inspection Scope

Following the scram on September 16, 1996, Residual Heat Removal (RHR) D circuit breaker failed to close during an attempt to manually start the pump for torus cooling. Torus water cooling was required to compensate for the heat added from Safety Relief Valves (SRVs), High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC), which were used to control reactor pressure during the transient. The licensee initiated troubleshooting efforts to determined the reason for the RHR D breaker failure. Throughout the transient, A,C and B RHR pumps provided sufficient torus water cooling. The inspector reviewed the licensee's troubleshooting activities associated with the failed start attempt, and the subsequent corrective actions. Additionally, the inspector reviewed the maintenance history for the RHR D and other 4160 volt circuit breakers.

b. Observations and Findings

The initial troubleshooting on September 16, of the RHR D circuit breaker (4160 volt General Electric (GE) Magne Blast, Model AMH-4.76-250-1D) indicated an "open" in the closing circuit. After racking out the breaker for further troubleshooting, checks of the circuit breaker internals indicated continuity. Additionally, no abnormal indications were identified during a visual inspection of the breaker. The breaker was racked in and operators successfully closed the breaker from the control room. Based on a previous failure of the same circuit breaker, the licensee suspected that the breaker was not racked in tight enough. This would cause the contacts associated with the positive interlock to remain open and prevent the breaker from closing. The positive interlock provides personnel safety during breaker racking operations, which prevents the racking in of a closed circuit breaker.

On September 17, following the event, the licensee performed additional troubleshooting and noted that racking the breaker out slightly (less then a half of turn on the rackout tool) caused the same indication of an open in the closing circuitry as was observed during the troubleshooting the day before. As a result, the licensee replaced the 52IS switch associated with the positive interlock, and cleaned and lubricated the racking mechanisms as preventive measures. The breaker was cycled satisfactorily as a post maintenance test (PMT).

Based on the indications that the RHR D circuit breaker was not fully racked in, the licensee wrote WRs 96-04852-00 through 33 to verify that all safety-related circuit breakers that have an automatic close function were racked in fully. The PMT for these WRs was the satisfactory remote start of the connected equipment. On September 18, during the PMT for RHR D, the circuit breaker again failed to close.

WR 96-0482-32 was written as a detailed troubleshooting plan to further investigate the RHR D circuit breaker failures. Continuity checks of the closing circuitry indicated the same "open" as identified on September 16. Detail troubleshooting indicated that the "open" was at contacts 5-6 of switch 52SM/LS, and not at the 52IS switch as earlier suspected. Additionally, the licensee verified certain breaker measurements were within the manufacturer's allowed tolerances, and found no indication of breaker misalignment. Failure analysis by the licensee determined the cause to be a loose fixed contact within the switch resulting in intermittent failure of the contacts to always make at the same point. This resulted in the contacts intermittently closing on the high resistance film coating and preventing the continuity within the closing circuit. The inspector observed portions of the troubleshooting performed under WR 96-04852-32 and considered it to be appropriate. The inspector also examined the internals of the failed switch and contacts, and reviewed Memo JMD 96-425 and determined the failure mode to be reasonable.

Contacts 5-6 of switch 52SM/LS provide the function for an automatic close permissive or for a white light indication. Neither of these functions are used at FitzPatrick. The licensee identified that switch 52SM/LS contacts 5-6 were not required as a result of a February 1996 failure of the switch in both RHR service

water (SW) pump circuit breakers. These failures were described in NRC Inspection Reports 50-333/96-01 & 96-03. Additionally, the RHR SW pump circuit breaker failures were described in Licensee Event Report (LER) 50-333/96-002. The license determined that these failures were age-related and replaced the 52SM/LS contacts 5-6 in all safety-related circuit breakers having more than 1,500 close cycles, which included the RHR D pump breaker. The license also developed Modification D1-96-052 to jumper out the switch 52SM/LS contacts 5-6 on all safety-related 4160 circuit breakers that require automatic or manual closure to perform the intended accident mitigation function. This modification was scheduled to be installed during the upcoming refueling outage scheduled for October 1996. However, as a result of the problems identified with the RHR D breaker, the licensee completed the modification on all applicable breakers prior to plant startup. The inspectors determine the modification to be technically sound, containing the required reviews and approvals. The inspector also reviewed the WR to install the modification on the RHR D circuit breaker and determined it to be adequate, containing an appropriate post modification test.

The inspector reviewed the maintenance history of the RHR D circuit breaker with the maintenance engineer. After the 52SM/LS switch was repaired in February 1996, the breaker had successfully passed all required surveillances until May 8, 1996, when it failed to close during the performance of Procedure ST-2HB, LPCI Initiation Logic System B Functional Test." WR 96-02944-00 was used to complete the troubleshooting of this failure, and cause of the failure was documented in Memo JMD-96-277, dated June 3, 1996. The memo provided several possible causes for this failure, all associated with the positive interlock portion of the closing circuitry. The licensee determined that no corrective actions were required since the safety-related breakers that have a close function, are regularly operated and surveillance tested, which would detect positive interlock related failures. Between May 8 and September 12, 1996, the breaker had been successfully cycled six times without a failure.

The inspector reviewed the surveillance completed on May 8, and the related work documentation. The inspector noted that, although the licensee had identified the apparent root cause to be associated with the positive interlock portion of the closing circuitry, they were unable to confirm the failure location.

c. Conclusions

The inspectors determined that the troubleshooting associated with the September 16 and 18 failures of the RHR D circuit breakers was adequate and the corrective actions taken to modify the applicable safety-related circuit breakers was appropriate. However, the inspector considered troubleshooting associated with the May 8, 1996, failure of the RHR D circuit breaker to lack rigor, in that it did not adequately review the recent past problems with the 52SM/LS, and it assumed the location of the problem without positive confirmation.

E8.3 Traversing In-Core Probe (TIP) System Ball Valve Control Failure

a. Inspection Scope (73051)

During restoration of power, following the September 16 turbine trip, a power supply failure in the TIP torque control unit caused the three TIP ball valves to open with a Group 2 containment isolation signal present. The inspector reviewed the licensee's actions to comply with TS and corrective actions for failure of the containment isolation valve.

b. Observations and Findings

The licensee declared the TIP system inoperable and removed power from the motor control units. The power to the motor control units was subsequently administratively controlled utilizing a protective tagout request (PTR) and reactor analyst procedure RAP-7.3.14, Traversing Incore Probe System. The procedure directs clearing of the PTR prior to commencing TIP runs and the re-establishment of the PTR when the work is completed. In addition, the isolation valves are being tracked daily by performance of ST-1H, Primary Containment Isolation Valve Inoperable Test and in the control room LCO log.

The TIP system was upgraded in February 1991 (modification FI-88-253) to improve system reliability, availability, and accuracy. This Siemens design replaced an older General Electric design and, as reported by NYPA, is the only Siemens unit operating in this application in the United States. Preliminary review by the licensee determined that a power supply failure in the torque control unit caused an errant signal to be sent from the position encoders to the valve control unit for the three ball valves. The errant signal indicated that the TIP probes were in the vessel and the valve logic is such that this signal results in the ball valves opening.

c. Conclusion:

The inspector concluded that adequate controls were in place to ensure compliance with technical specifications (TS) for an inoperable containment isolation valve. The licensee is continuing to investigate the failure of the power supply and opening of the isolation valves therefore this issue will remain unresolved **(URI 50-333/96006-04)**.

E8.4 (Closed) (URI) 50-333/95021-02: Environmentally Qualified (EQ) Electrical Fuses

a. Inspection Scope

The inspector reviewed the licensee's action plan, JSED-APL-95-019, Revision 4, governing the discrepant fuses in EQ applications noted in NRC Inspection Report 50-333/95-21, as well as root cause evaluation report JAF-RPT-ELEC-02316 on this issue. The inspector also reviewed the licensee's EQ justifications for continued operation JAF-EQ-JCO-96-01, Revision 1, and 96-02, Revision 0, as well as AP-5.12, Revision 4, Replacement of Electrical Fuses.

b. Observations and Findings

After inspection of the fuses in all 138 EQ motor control centers and electrical panels, a total of 18 fuse discrepancies were identified and were subsequently resolved by fuse replacement or development of EQ supporting documentation. Identification of EQ fuse concerns and subsequent change out of the fuses in question was completed on all equipment within the applicable LCO action time. The root cause evaluation determined that the majority of the discrepancies were caused by breakdowns in the fuse selection process as well as weaknesses in the modification/work process interface. Specifically, operators and maintenance personnel confused fuses that are environmentally qualified with fuses that were procured for safety-related, non EQ applications as they were identical in appearance. Furthermore, adequate documentation verifying the environmental qualification of certain fuses qualified by similarity was not provided or errors were made in the Bill of Materials for the fuses in specific components. However, in six of the 18 cases, the breakdown in the process governing the installation of EQ fuses could not be determined.

A broad range of corrective actions were implemented to prevent a recurrence of this problem to address each of the root causes identified. Substantial progress has been made in the implementation of these corrective actions which included a revision to AP-5.12, Employee Training, quality assurance (QA) follow-up audits and creation of a procedure on generating a proper Bill of Materials.

The inspector noted that the licensee has an ongoing fuse control action plan to address additional non-EQ fuse discrepancies identified recently, most in response to an operations department effort to validate the accuracy of operator aids in the plant. This action plan, JSED-APL-95-008, is in the process of being implemented.

c. Conclusions

The licensee performed a thorough and detailed root cause investigation of the EQ fuse discrepancies identified and developed a comprehensive series of corrective actions to prevent recurrence. The majority of these corrective actions have been completed. The success of these corrective actions is, in part, reflected by the absence of EQ related fuse discrepancies in the last six months in spite of an extensive ongoing fuse control program verification and improvement program. However, since documentation of the environmental qualification of the fuses in question was not in an auditable form as required by 10 CFR 50.49.j, a violation of NRC requirements occurred. This violation will not be cited in accordance with Section VII.B.1 of the NRC Enforcement Manual as the violation was licensee identified, non-recurring, promptly and thoroughly corrected and of low safety significance **(50-333/9606-05)**.

E8.5 Review of UFSAR Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the updated final safety analysis report (UFSAR) description highlighted the need for a

special-focused review that compares plant practices, procedures, and/or parameters to the UFSAR description. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls (84750)

R1.1 Management Controls

a. Inspection Scope

The inspectors reviewed the management controls implemented by observation of management-staff interactions; interviews; and review of program/organization changes, quality assurance (QA) audits, and review of the semi-annual radioactive effluent report.

b. Observations and Findings

The inspectors reviewed changes to the organization and administration of the radioactive liquid and gaseous effluent control programs and determined that responsibility for the programs had moved from the Operations General Manager to the Support Services General Manager. The Chemistry staff had primary responsibility for conducting the radioactive liquid and gaseous effluent control programs. The Operations, Engineering, Radwaste, and Instrumentation and Controls departments supported the radiological effluent control programs relative to air cleaning systems, radioactive liquid discharges, and radiation monitoring system calibrations.

The inspectors reviewed QA Audit Report No. 96-01J (completed February 27, 1996). The audit was conducted by Nuclear Quality Assurance (NQA) personnel and covered the radioactive liquid and gaseous effluent control programs. The audit findings were administrative in nature and were not of regulatory significance. The inspectors noted that the audit team was composed of members with appropriate technical expertise to assess the radioactive liquid and gaseous effluent control programs. The inspectors also reviewed QA Surveillance Report (SR) No. 1878 which assessed operations performance for a simulated liquid effluent release. The inspectors considered this to be a good initiative on the part of the licensee because there were no opportunities to observe an actual planned release of liquid effluents during 1995.

The inspectors reviewed the 1995 Semi-annual Radioactive Effluent Release Reports. These reports provided data indicating total released radioactivity for liquid and gaseous effluents. These reports also summarized the assessment of the

projected maximum individual and population doses resulting from routine radioactive airborne and liquid effluents. Projected doses to the public were well below the Technical Specification (TS) limits. The 1995 Semi-annual Reports properly assessed unplanned releases, as required by TS. The inspectors determined that there were no anomalous measurements, omissions or adverse trends in the reports.

c. Conclusions

The licensee implemented good management control and oversight of the quality of the radioactive liquid and gaseous effluent control programs.

R1.2 Review of the Offsite Dose Calculation Manual (ODCM)

a. Inspection Scope

The inspectors reviewed the ODCM implemented at the FitzPatrick Nuclear Power Plant, including: (1) dose factors, (2) setpoint calculation methodology, (3) bioaccumulation factors for aquatic sample media, (4) LER 96-001 which pertained to the ODCM, and (5) the impact of hydrogen water chemistry and the ability to comply with 40 CFR 190.

b. Observations and Findings

The ODCM provided descriptions of the sampling and analysis programs, which were established for quantifying radioactive liquid and gaseous effluent concentrations, and for calculating projected doses to the public. All necessary parameters, such as effluent radiation monitor setpoint calculation methodologies, site-specific dilution factors, and dose factors, were listed in the ODCM. The licensee adopted other necessary parameters from Regulatory Guide 1.109. The inspectors noted that the most recent submittal contained improved detail as compared to previous submittals.

The inspectors reviewed the licensee's actions relative to LER 96-001, Failure to Implement Radiation Monitor Instrumentation Setpoint Changes Following Revision to the ODCM. The inspectors assessed that the LER dispositioned an ODCM-related discrepancy that was not of regulatory significance. The inspectors had no further questions regarding LER 96-001 and considered it closed.

The inspectors reviewed several licensee studies concerning hydrogen water chemistry and considered these studies to be comprehensive. Based upon the licensee survey data, the licensee appeared to be in compliance with the requirements of 40 CFR 190 relative dose to members of the public at the current hydrogen injection rate of 18.5 scfm. The inspectors noted to the licensee that there could be a potential for a compliance problem with 40 CFR 190 relative to Niagara Mohawk Power (NMP) Corporation personnel occupying the adjacent NMP owner controlled areas at higher hydrogen injection rates if no compensatory measures were to be taken. The licensee was aware of this potential problem and

was analyzing methods of managing this situation in anticipation of the need to increase the hydrogen injection rates for increased protection against inter-granular stress corrosion cracking.

c. Conclusions

The inspectors determined that the licensee's ODCM contained sufficient specification, information, and instruction to acceptably implement and maintain the radioactive liquid and gaseous effluent control programs. Licensee analyses of the dose impact to members of the public as the result of hydrogen water chemistry were good.

R1.3 Implementation of Radioactive Liquid and Gaseous Effluent Control Programs

a. Inspection Scope

Inspection of this area consisted of: (1) physical walkdown of facilities and equipment, including the control room; (2) review of selected licensee's procedures; and (3) review of selected radioactive liquid and gaseous discharge permits with respect to TS/ODCM requirements.

b. Observations and Findings

During a plant tour, the inspectors noted that all effluent Radiation Monitoring Systems (RMS) were operable at the time of this inspection. The inspectors noted that the effluent control procedures were detailed, easy to follow, and ODCM requirements were incorporated into the appropriate procedures. The inspectors also determined that the gaseous discharge permits were complete, and met the TS/ODCM requirements for sampling and analyses at the frequencies and lower limits of detection established in the TS.

During a discussion with Chemistry staff, the inspectors noted that the responsible individuals had maintained and enhanced their knowledge in the areas of: (1) radioactive liquid and gaseous effluent controls; (2) effluent and process RMS; (3) the application of procedures designed to protect the public health and safety, and the environment; and (4) the TS and ODCM requirements.

c. Conclusion

Based on the above observations, reviews and discussions, the inspectors determined that the licensee established, implemented, and maintained effective radioactive liquid and gaseous effluent control programs.

R1.4 Calibration of Effluent/Process Radiation Monitoring Systems (RMS)

a. Inspection Scope

The inspectors reviewed the most recent calibration results for the following effluent and process RMS to determine the implementation of the TS requirements and Updated Final Safety Analysis Report (UFSAR) commitments:

- Liquid Radwaste Discharge Monitor,
- Service Water Discharge Monitor,
- Main Steam Line Radiation Monitors,
- Reactor Building Closed Loop Cooling Radiation Monitor,
- Main Stack - Normal and High Range Noble Gas Monitors,
- Refuel Floor Exhaust Radiation Monitor,
- Reactor Building Exhaust Radiation Monitor,
- Turbine Building Exhaust - Normal and High Range Monitors,
- Radwaste Building Exhaust - Normal and High Range Monitors, and
- Offgas Radiation Monitor

b. Observations and Findings

The I&C Department and Radiological and Environmental Services Department (Chemistry) had the responsibility of performing electronic and radiological calibrations, respectively, for the above effluent/process radiation monitors. A system engineer had the responsibility to maintain the above RMS operable and upgrade the system, as necessary. All radiological calibration results reviewed were within the licensee's acceptance criteria.

During the review of the above RMS radiological calibration results, the inspectors independently verified several calibration results, including linearity tests and conversion factors. The inspectors used a linear regression for the comparisons and the comparisons were in good agreement. The licensee stated that a statistical method, such as a linear regression, would be reviewed and applied as necessary.

The inspectors discussed effluent RMS operability/reliability with Chemistry staff. From this interview, the inspectors determined that the Chemistry staff had good knowledge of the effluent RMS relative to operability requirements and performance history. The inspectors also noted that Chemistry trended the operability of the effluent RMS.

The licensee maintained a system for monitoring the reliability of the effluent RMS. The licensee tracked the comparison between effluent monitor reading results and expected monitor readings determined from laboratory sample measurements, to ensure that the effluent RMS responded acceptably. The inspectors reviewed these comparison results for liquid and gaseous effluent monitors during this inspection and determined that the licensee's comparisons were in reasonably good agreement.

c. Conclusions

The licensee has implemented effective programs for effluent RMS calibration and reliability assessment.

R1.5 Air Cleaning Systems

a. Inspection Scope

The inspectors walked down systems, reviewed the licensee's most recent surveillance test results, and interviewed the system engineer assigned to manage the station air cleaning systems to determine the implementation of TS requirements and the UFSAR commitments for: (1) the standby gas treatment system; (2) the control room ventilation system; (3) technical support center system; and (4) the radwaste building air cleaning system.

b. Observation and Findings

The inspectors reviewed the following surveillance test results:

- Visual Inspection,
- In-Place HEPA Leak Tests,
- In-Place Charcoal Leak Tests,
- Air Capacity Tests,
- Pressure Drop Tests, and
- Laboratory Tests for the Iodine Collection Efficiencies.

All test results were within the licensee's TS acceptance criteria. One individual within the Engineering Department was assigned to manage the station ventilation systems. All TS and UFSAR tests were conducted at the prescribed frequencies. Unsatisfactory test results were analyzed and corrective actions were implemented in a timely manner. The inspectors noted that attention given to the air cleaning systems was excellent. The System Engineer monitored and trended the performance of the air cleaning systems.

c. Conclusion

The licensee has implemented very good air filtration/ventilation system surveillance programs for systems described in the TS and UFSAR. Attention placed on station air cleaning systems by the engineering department was very good.

R5 Staff Training and Qualifications in RP&C

a. Inspection Scope (83522)

The inspector reviewed the training provided to both plant radiological workers and health physics technicians. The inspector toured training facilities and also audited one training class for health physics technicians.

b. Observations and Findings

Since the last inspection in this area, the licensee constructed a new enhanced radiation worker (ERW) training facility in the training center. As previously discussed (NRC Inspection Report 50-333/96-03) this training program was developed to address concerns with the practices of plant radiation workers observed during and immediately after the last refueling outage (RFO11). The new training facility is a very close approximation of the environment typically encountered in the plant, and stresses contamination control and radiological condition awareness. All current plant employees have taken or will have taken this training prior to the commencement of the next refueling outage (RFO12).

The inspector reviewed plant records and observed numerous plant workers entering and working in the reactor facility. A general improvement in worker practices was observed.

The inspector also attended one training session for health physics technicians and supervisors. The session attended was on control of radiological activities on the refueling floor during an outage. Since the next refueling outage is scheduled to commence at the end of October, this session was very timely. The session was set-up to encourage classroom participation and use the instructor in the role of discussion moderator.

c. Conclusions

Training activities continue to support and aid in improving plant radiological worker practices. Additionally, specialized training for health physics technicians was both timely and well presented.

R6 RP&C Organization and Administration

a. Inspection Scope (83522)

The inspector reviewed management organization in the radiological controls program, including maintaining occupational radiation exposure as low as is reasonably achievable (ALARA), control of radiological work and radiological housekeeping. The inspector made frequent tours of the radiologically controlled area (RCA), and discussed specific radiological controls with the radiation protection supervisors and various radiation protection technicians.

b. Observations and Findings

In accordance with plant Technical Specifications, responsibility for safe radiological operations at the facility are the responsibility of the Plant Manager. The Radiological and Environmental Services (RES) Manager serves as radiation protection manager at the facility, and reports through the General Manager - Support Services to the Plant Manager. The RES department is split between chemistry and health physics groups. The health physics group consisted of a

radiological engineering manager, health physics manager and technical staff. Additionally the health physics manager has several supervisors reporting directly to him relative to instrumentation and respiratory protection, decontamination and shipping, ALARA and operational health physics. Recent modifications included changing the supervisor for dosimetry, and placing the responsibility for RES under the General Manager - Support Services. Previously the RES Manager reported to the General Manager - Operations.

Discussions with various managers, supervisors and technicians indicated that all had an appropriate awareness of previously identified problems within the RES Department, and that all were aware of actions taken to address these issues. These issues, previously identified and discussed in NRC Inspection Report No. 50-333/95-10 included poor radiological worker practices, failure of the health physics technicians to provide appropriate support to the plant staff, and a failure of the health physics group to properly utilize or respond to findings and recommendations made during quality assurance reviews. Interdepartmental communications appeared to be the common problem still needing to be addressed. All personnel contacted identified this as a key issue that still needed to be resolved.

Since the last inspection in this area (documented in NRC Inspection Report 50-333/96-03), the unit has generally been operating at or near full power, while continuing preparations for refueling outage 12 (RFO12) planned for late October 1996. During this inspection, several tours of various facilities located within the radiologically controlled area (RCA) were conducted. Extensive efforts by the licensee during the past year have led to notable improvement in the area of radiological housekeeping. Especially notable was the condition of the areas on the refueling floor. Also observed during these tours was the significant amount of scaffolding being erected in the reactor building in preparation for the RFO12 to support snubber inspections taking place. These inspections are occurring before the start of RFO12 in order to reduce the scope of work which must be performed during the outage, and consequently the outage length. Data from previous outages indicates that 3-5 person-rem per day can be saved by minimizing the outage length. All inspections were taking place in locations not affected by power operations, and therefore not leading to additional occupational exposure.

For RFO 12, the licensee established goals of not more than 45 days and not more than 168.8 person-rem. The ALARA goal was established at the end of 1995, and is part of the annual site goal of not more than 260 person-rem. At the time of this inspection, only four ALARA reviews in support of the refueling outage remained to be completed. Data on total person-hours to be worked on four specific tasks had not yet been provided by the appropriate working groups in order to complete these associated ALARA reviews. The licensee anticipated completing these remaining reviews by mid-September.

Current estimates by the ALARA staff show an anticipated total outage exposure of 184 person-rem, so that considerable exposure savings will have to be realized if the licensee is to meet its outage exposure goal.

c. Conclusions

Plant management appears to have a good understanding of previously identified problems involving radiation workers and health physics technicians, actions taken to address these problems. Outage preparations appear appropriate in order for the facility to meet its goals for outage duration and occupational exposure.

R7 Quality Assurance in RP&C Activities

a. Inspection Scope (83522)

The inspector reviewed audits, surveillances and RES self-assessments in order to evaluate the effectiveness of quality assurance activities in the RES department. The inspector also discussed planned audits for the remainder of the year with Quality Assurance (QA) personnel.

b. Observations and Findings

Table R7 provides a listing of audits, surveillances and RES department self-assessments reviewed by the inspector. The scope and technical depth of these reviews, especially in the self-assessments, was significantly improved over those reviewed during previous inspections. More importantly was the acceptance of findings and recommendations contained in these documents by RES management and staff. Findings and recommendations are now being promptly addressed and the adequacy of responses verified by RES management prior to submittal to QA.

An audit of the health physics program by the QA department is scheduled to commence in September, 1996. The lead auditor is a QA engineer who has previously served as Radiological Engineering and Health Physics Manager within the RES department. Several technical experts from outside the New York Power Authority have also been hired to assist in the audit. The self-assessment program also is continuing, but will be temporarily suspended during the refueling outage.

c. Conclusions

Audits and surveillances provided by the QA department continue to be of high quality. The RES department had made significant improvements in the areas of self-assessment and acceptance of QA findings and recommendations.

R8 Miscellaneous Issues

R8.1 Evaluation of Unmonitored Release After September 16, 1996 Scram

a. Inspection Scope (71750)

The inspector observed the performance of the EP radiological staff during the event and reviewed radiological records and surveys. Survey results were reviewed to determine the extent of radiological release.

b. Observations and Findings

After the September 16, 1996, plant scram, turbine building ventilation was isolated while there were steam leaks from a blown low pressure turbine and a reactor feed pump rupture disk. Pressure in the turbine building resulted in steam exiting from the turbine building, indicating an unmonitored release. During the event, onsite surveys were conducted by survey teams which indicated that no release occurred. Calculations were performed using conservative assumptions which showed that if any release occurred, it was negligible. The EP radiological coordinator directed appropriate surveys and remained cognizant of radiological activities. Subsequent to the event, environmental monitoring samples were collected and surveyed and direct reading radiation monitors were read. The result was that no increase in radiation levels was observed as a result of the plant transient. Analysis results for the environmental samples were less than detectable for all plant related radionuclides.

c. Conclusions

During the event, EP radiological activities were well coordinated. Based on surveys and environmental radiation monitoring results, there was no indication of any increased radiation levels associated with the September 16, 1996 event.

P1 Conduct of Emergency Preparedness (EP) Activities

a. Inspection Scope (71750)

The inspectors observed the EP organization performance during the September 16, 1996, plant event. A review of EP staffing, event classification and notification and facilities using IAP-1, Emergency Plan Implementation Checklist and IAP-2, Classification of Emergency Condition, and review of the technical support center (TSC) and operational support center (OSC) logs and activities were also performed.

b. Observations and Findings

At 1:40 p.m. on September 16, approximately 36 minutes after the initial plant scram, the event was classified as a notification of unusual event (NUE) in accordance with emergency action level (EAL) 7.2.1, main turbine failure resulting in casing penetration or damage to turbine seals or generator seals. The event notifications were completed by 2:16 p.m. and additional followup notifications were made as necessary. The NRC entered the monitoring phase at the incident response center. The licensee staffed the TSC and OSC to provide support to operations and the EP organizations were operational at 2:10 p.m. At 2:36 a.m. on September 17, the NUE was terminated upon restoration of the main condenser and verification of cooldown capability.

c. Conclusions

The implementation of the emergency plan was a sound decision. The event was appropriately classified, notifications made and the TSC and OSC were properly staffed and provided assistance to operators in a timely manner. EP procedures, logs and status boards were in use and significant EP facility discrepancies were not evident.

P3 EP Procedures and Documentation

An in-office review of revisions to the emergency plan implementing procedures submitted by the licensee was completed. A list of the specific revisions reviewed are included in Attachment 1 to this inspection report. The inspector concluded that the revisions did not reduce the effectiveness of the emergency plan and were acceptable.

F8 Miscellaneous Fire Protection Issues

F8.1 Performance of the Fire Suppression System during the September 16 Plant Transient

a. Inspection Scope

During the September 16, 1996, plant transient, fire suppression sprinkler systems within the turbine building condenser area actuated, and the fire header above the turbine bearings charged, but did not actuate. The inspectors reviewed the licensee's evaluation of the fire protection system performance during the event, and the work requests (WRs) associated with the replacement of the affected sprinkler heads. Additionally, discussions were held with the fire protection engineer, and the fire protection system engineer regarding the system performance, post transient plant inspections and restoration of fire protection equipment.

b. Observations and Findings

During the September 16 plant transient, both the reactor feed water pump (RFP) turbine exhaust header and the main turbine hood disc ruptured, causing local temperatures to increase. The increase in temperature resulted in the actuation of the fire suppression sprinkler system within the turbine building condenser area, and the fire water header above the turbine bearings charged. During the recovery from the event, operators appropriately secured the fire suppression system.

Following the event, the system engineer walked down portions of the fire protection systems, including the sprinklers, fire detection panels and emergency lights, and determined that fire protection equipment responded as designed to the event. In areas that were wetted by the fire water released, the licensee performed inspections of the electrical panels, cabinets and junction boxes for water intrusion with no problems identified.

Subsequently, the licensee drained the fire header above the turbine bearings and returned it to service. Additionally, the fire suppression sprinkler headers that had actuated, and surrounding sprinkler heads which the licensee determined may have degraded due to the increased temperatures experienced during the event, were replaced under WR 96-04792-00. A total of 41 sprinkler heads were replaced with an equivalent model head as evaluated in Design Equivalent Modification D1-92-197. The system was subsequently leak tested under WR 96-04792-02, and returned to service. The inspector reviewed portions of the completed WRs and the design equivalent modification, and determined them to be appropriate.

c. Conclusions

The fire suppression system equipment performed as designed during the September 16 plant transient. The licensee's inspections of wetted equipment resulting from the actuation of the sprinkler system, and subsequent sprinkler head replacement were reviewed by the inspector and determined to be appropriate.

S1 Conduct of Security and Safeguards Activities

a. Inspection Scope (71750)

The inspector observed security force member support during the September 16 event.

b. Observations and Findings

The September 16 transient resulted in the loss of normal plant communications and vital area doors failed in the locked position. Security personnel were assigned to strategic areas in the plant to help with access and communication for operations personnel.

c. Conclusions

Security force members responded in a timely manner to assist with plant communications and vital area access.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspections results to members of the licensee management at the conclusion of the inspection on October 10, 1996. The licensee acknowledged the findings presented and noted that none of the materials examined during the inspection was considered proprietary information.

PARTIAL LIST OF PERSONS CONTACT

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INSPECTION PROCEDURES USED

37551	Onsite Engineering
62703	Maintenance Observations
61726	Surveillance Observations
71707	Plant Operations
71750	Plant Support
83522	Radiation Protection Organization and Management Controls
84750	Radioactive Waste Treatment, and Effluent and Environmental Monitoring

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-333/96006-001	VIO	Maintenance planning and work associated with WR 96-02875-00 to perform calibration of 71-59N-1UPRN05 was improperly performed resulting in a reverse power scram and plan transient
50-333/96006-002	URI	Condenser response related to September 16, 1996 reverse power scram (i.e. MSIV isolation signal input on low condenser vacuum)
50-333/96006-003	IFI	Seismic qualification process for commercial grade equipment
50-333/96006-004	URI	Failure of a TIPs power supply resulting in opening three containment isolation valves
50-333/96006-005	NCV	Documentation of environmental qualification of fuses were not in an auditable form

Closed

50-333/9521-002	URI	EQ fuse discrepancies and resulting corrective actions to prevent recurrence
50-333/96-001	LER	Failure to implement radiation monitoring instrumentation setpoint changes following revision to the offsite dose calculation manual (ODCM)

50-333/96-009 LER Incorrect Time Delay Relay Installation for Emergency Diesel Generator

Discussed

None

ATTACHMENT 1

EP Implementing Procedures Reviewed

Document	Document Title	Revision
E-Plan	Appendix H	19
EAP-3	Fire	18
EAP-5.3	Onsite/Offsite Downwind Surveys and Environmental Monitoring	4
EAP-8	Personnel Accountability	32
EAP-17	Emergency Organization Staffing	71
EAP-22	Operation and Use of Radio Paging Device	25
EAP-43	Emergency Facilities Long Term Staffing	32
SAP-2	Emergency Equipment Inventory	20
SAP-3	Emergency Communications Testing	49
SAP-7	Monthly Surveillance Procedure for On-Call Employees	29
SAP-8	Prompt Notification System Failure/Siren System False Activation	9

ATTACHMENT 2

Procedures Reviewed Related to September 16, 1996 Event

Document	Document Title	Revision
EOP-2	Reactor Pressure Vessel Control	2
EOP-4	Primary Containment Control	2
AOP-1	Reactor Scram	28
AOP-21	Loss of UPS	2
AOP-31	Loss of Condenser Vacuum	10
AOP-57	Recovery from Residual Bus Transfer	2
OP-4	Circulating Water System	33

ATTACHMENT 3

September 16, 1996 Sequence of Events

1304 While performing 345 KV relay maintenance, I&C technicians shorted across relay contacts which simulated a main generator neutral bus ground fault.

Output breakers trip, main turbine and generator trip, reactor scram on turbine control valve fast closure.

Residual bus transfer results in loss of balance of plant loads and uninterruptible power supply.

All 4 emergency diesel generators start but do not load (as designed).

The "G" safety relief valve opens, reactor pressure peaks at 1082 psig.

High pressure coolant injection and reactor core isolation cooling start at low reactor vessel level.

Recirc pumps trip and alternate rod insertion on low reactor vessel level.

Lowest indicated reactor vessel level at 126" (normal reactor vessel operating level is 201.5 ").

Operators entered EOP-2, reactor pressure vessel (RPV) Control, on low RPV water level.

1305 Turbine bypass valves close on loss of electro-hydraulic control (EHC).

The reactor feed pumps trip on low suction pressure due to loss of condensate pumps.

1311 (Approx time) B LP turbine rupture disc ruptures. Turbine building pressure reached 3 psig. Also, B RFP rupture disc ruptured at 5 psig.

1313 Loss of A and B RPS during manual transfer, MSIVs close.

1323 The "B" RPS was restored.

1327 The "A" RPS was restored.

1329 Operators attempt to restore UPS.

1335 TIP isolation valves open.

1340 The E-plan was entered and an unusual event was declared.

1353 Operators started the B RHR pump for torus cooling, D RHR pump failed to start.

1410 TSC and OSC staffed.

1415 Blown rupture disk confirmed on B LP turbine.

1417 Operators successfully restored the UPS.

1421 Reset PCIS isolation and verified all rods in via full core display.

1623 Fuel pool cooling restored.

1658 Cycled D RHR pump breaker, started D RHR pump.

2016 Restored circ water system.

2022 rupture disc on LP turbine installed.

2356 MSIVs opened.

0205 Condenser vacuum reestablished. BPV used for RPV control.

0236 Exited unusual event.

0544 Started shutdown cooling on B RHR pump.

0600 Coolant temperature less than 212 degrees.

0614 Mode switch in refuel.

TABLE R7

Listing of Audits, Surveillances and
Self-Assessments Reviewed

Action Plan to Improve Radiological Performance, Rev 1, July 12, 1996

Review of the JAF Radiation Protection Program, January - July 1996, August 9, 1996

RES Department Six Month Self-Assessment, August 26, 1996

JRES-SAR-96-008, Sealed Source Leak Rate Testing, May 22, 1996

JRES-SAR-96-009, Radiation Worker Practices, July 17, 1996

JRES-SAR-96-011, Informational Content of ALARA, Dosimetry and Radiation Protection Records, Logs and Reviews, July 30, 1996

QA-SR-1865, Yankee Atomic Environmental Laboratory TLD Processing Review, May 13, 1996

QA-SR-1873, Review of the Action Plan to Improve Radiological Performance, Action Plan No. JRES-APL-95-015, June 28, 1996

QA-SR-1879, Radwaste Shipment No. 0696-6061, July 12, 1996

QA-SR-1892, Receipt Inspection of HIC L-490261-55, August 8, 1996

QA-SR-1898, Inspection of the Capping and Storage of HIC Line L-490261-55 and Receipt Inspection of HIC Liner L-490261-40, August 14, 1996

QA-SR-1902, Inspection of the Capping of HIC Liner L-490261-40, August 21, 1996