U. S. NUCLEAR REGULATORY COMMISSION
REGION 1

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License Nos.	DPR-50 DPR-73
Licensee:	GPU Nuclear Corporation P.O. Box 480 Middletown, PA 17057
Facility:	Three Mile Island Station, Units 1 and 2
Location:	Middletown, Pennsylvania
Inspection Period:	December 4, 1990 - January 19, 1991
Inspectors:	Francis I. Young, Senior Resident Inspector David M. Johnson, Resident Inspector David P. Be: ulieu, Resident Inspector
Approved by:	William H. Ruland 2/15/91 William Ruland, Chief Date Reactor Projects Section No. 4B

Inspection Summary

The NRC Staff conducted routine and reactive safety inspections of Unit 1 power operations and Unit 2 cleanup activities. The inspectors reviewed plant operations, maintenance and surveillance, radiological practices, security measures and engineering support activities as they related to plant safety.

Results: An overview of inspection findings are in the executive summary.

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EXECUTIVE SUMMARY

Three Mile Island Nuclear Power Station
Report Nos. 50-289/90-21 & 50-320/90-12

Plant Operations

Overall, Unit 1 plant operations were conducted in a safe manner. On December 22, 1990, reactor power was reduced and increased twice without incident when the dispatcher declared a minimum generation emergency which required the licensee to load follow.

The Unit-2 accident generated water evaporator was shut down for six weeks to repair a failed compressor. Evaporator startup testing was conducted on January 14, 1991.

On January 3, 1991, an evaporator building exhaust blower, which contains a radiation monitor used to continuously monitor for airborne contamination, was secured. A Health Physics technician requested that the exhaust blower be secured because the air currents could have resulted in airborne contamination while emptying the blender/dryer. This was in violation of the NRC approved evaporator operating procedure and the licensee was issued a non-cited violation. The procedure non-compliance was of low safety significance because several local airborne contamination samples were taken and no airborne contamination was detected.

Radiological Controls

Routine observations of radiological controls were conducted throughout the inspection period. No noteworthy observations were made.

Elevated levels of tritium were observed at a groundwater monitoring well that was expected to have only natural background tritium levels. The licensee believes that the source of the tritium was likely to be from a feedwater heater draining evolution, however, further investigation is being conducted. The tritium levels are below regulatory limits and do not pose a radiological concern. The elevated tritium was not caused by accident generated water leakage.

Maintenance

The licensee continues to conduct maintenance activities in a safe and timely fashion. No noteworthy observations were made.

Security

Routine review of this area identified no noteworthy observations.

Safety Assessment and Quality Verification

Two Plant Review Group (PRG) operability assessments were evaluated associated with a significantly degraded Decay Heat Closed Cooling Water system and a degraded diesel generator. In both assessments, the basis for declaring the systems operable was poorly documented and therefore required much inspector follow-up questioning. The inspector has not had the opportunity to fully evaluate the licensee's ability to identify and correct these system degradations and therefore is making each of these an unresolved item.

DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

1.1 Licensee Activities

The licensee began the inspection period operating at 94 percent power. Reactor power was limited to 94 percent due to Once Through Steam Generator (OTSG) operation near the Integrated Control System high level limit because of OTSG secondary side fouling. Reactor power slowly decreased during the inspection period to 93 percent due to continued OTSG secondary side fouling. On December 22, 1990 there were successive power reductions (to 89 percent and 84 percent) and escalations because the dispatcher declared a minimum generation emergency which required the licensee to do some load following.

The Accident Generated Water evaporator was shut down for six weeks to repair a failed compressor. Evaporator startup testing was conducted on January 14, 1991.

1.2 NRC Staff Activities

This inspection assessed the adequacy of licensee activities for reactor safety, safeguards and radiation protection. The inspectors made this assessment by reviewing information on a sampling basis, through actual observation of licensee activities, interviews with licensee personnel, or independent calculation and selective review of applicable documents. Inspections were accomplished on both normal and back shift hours in accordance with NRC inspection procedures.

1.3 Persons Contacted

D. Atherholt, Operations Engineer
*G. Broughton, Vice President and Director
J. Byrne, Manager, TMI-2 Licensing
S. Giacobbe, Manager, Plant Engineering
G. Giangi, Manager, Corp. Emergency Preparedness
R. Harper, Manager, Plant Material
C. Hartman, Manager, Plant Engineering
D. Hassler, Licensing Engineer
G. Kuehn, Site Operations Director, TMI-2
*R. Knight, Licensing Engineer
*M. Nelson, Manager, Safety Review
J. Paules, Senior Operations Engineer
*R. Rogan, Director, Licensing and Nuclear Safety
*M. Ross, Director, Plant Operations and Maintenance
T. Seaver, QA Auditor
*H. Shipman, Director, Plant Operations
*E. Schrull, Licensing Engineer
G. Simonetti, Manager Emergency Preparedness

*R. Skillman, Director, Plant Engineering
*P. Snyder, Manager, Plant Materiel Assessment
*C. Smyth, Manager, TMI-1 Licensing
J. Stacy. Manager, Security
R. Wells, Licensing Engineer
H. Wilson, TSS/ISI Coordinator

Other members present:

*R. Cook, Pennsylvania Department of Environmental Resources

* Denotes attendance at final exit meeting (see Section 7.0)

2.0 PLANT OPERATIONS

2.1 Operational Safety Verification

The inspectors observed plant operation and verified that the plant was operated safely and in accordance with licensee procedures and regulatory requirements. Regular tours were conducted on the following plant areas:

-- Control Room	-- Auxiliary Building
-- Switchge Areas	-- Turbine Building
-- Access Control Points	-- Intake Structure
-- Protected Area Fence Line	-- Yard Areas
-- Fuel Handling Building	-- Containment Penetration Areas
-- Diesel Generator Building	

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

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

Plant housekeeping controls were monitored, including control and storage of flammable material and other potential safety hazards. The inspector conducted detailed walkdowns of accessible areas, of both Unit 1 and Unit 2. No noteworthy observations were made.

2.2 Engineered Safety Features System Walkdown

The operability of selected engineered safety feature systems was verified by performing detailed walkdowns of the accessible portions of the systems. The inspectors confirmed that system components were in the required alignments, instrumentation was valved-in with appropriate calibration dates, as-built prints reflected the as-installed systems and the overall conditions observed were satisfactory. The systems inspected during this period include the Decay Heat Closed Cooling Water System and the Decay Heat Removal system. No concerns were identified.

2.3 Securing Evaporator Building Ventilation Exhaust Blower

On January 3, 1991, the licensee discovered that there had been a procedure non-compliance associated with the accident generated water evaporator. NuPac, the contractor assigned to operate the evaporator, was preparing to empty the contents of the blender/dryer. The blender/dryer is used to boil off any remaining water from the concentrate created in the evaporation process. The remaining dry powder is then packaged in drums.

The Health Physics (HP) technician assigned to the job was concerned about performing the drumming operations while the evaporator building ventilation blower was operating because this could create a potential airborne contamination problem due to the air flow drawn across the drumming station. The NuPac operator informed the HP technician that the blower could not be secured due to procedural requirements. The procedure referred to was 4215-OPS-3185.05, Rev.1, Processed Water Disposal System Operating Procedure, step 4.5 which states that the evaporator building ventilation exhaust blower shall be operating at any time water processing or solid waste processing or handling is in progress in the evaporator building. The purpose of this requirement is to ensure that the radiation monitor, which is installed in the exhaust system, will continuously monitor the evaporator building atmosphere to detect any airborne contamination. The HP technician believed the NuPac operator was referring to the HP paperwork, which does not require blower operation. The HP technician did not understand that blower operation was required by the operating procedure. The HP technician indicated that the job could not proceed if the blower was left on due to airborne contamination concerns.

Because of the HP technician/NuPac operator miscommunication, the operator secured the blower. However, several local airborne contamination samples were taken during the evolution and no airborne contamination was detected.

On January 4, 1991 GPUN held a critique to discuss these events and to decide what corrective actions were necessary. The corrective actions taken were as follows:

- TMI-2 engineering and radiological engineering met to evaluate whether the blower should be secured during the blender/dryer dumping evolution. A smoke test was performed to evaluate air flow near the blender/dryer during various conditions of blower and damper operation and concluded that air flow is not affected enough to warrant securing the blower. Therefore, GPUN decided to leave the procedure as written.

- The TMI-2 Site Operations Director re-instructed NuPac personnel on the necessity of procedure compliance. The TMI-2 Manager of Operations and Maintenance briefed the shift foremen and control room operators that their assistance may be requested in the future to help resolve similar problems, especially during backshift, since they are more familiar with GPUN administrative requirements than NuPac personnel.

On January 4, 1991, the resident inspector was notified by the licensee of the events surrounding the procedure non-compliance associated with securing the evaporator building ventilation blower. The inspector reviewed these events and determined that this procedure non-compliance was a licensee identified violation. The event was reviewed against the enforcement discretion criteria of 10 CFR 2, Appendix C. The inspector concluded that the event: (a) was identified by the licensee (b) would normally be considered a Severity Level V violation, (c) though not required, was reported to the NRC, (d) adequate corrective action was promptly taken and (e) had not been a repeat event. Accordingly, a Notice of Violation will not be issued. (50-320/90-12-001)

2.4 Status of Accident Generated Water (AGW) Evaporation

On December 2, 1990, the AGW evaporator compressor failed. The licensee concluded that excess drive shaft axial torque caused oscillations and seizure in the labyrinth seal area which caused a drive shaft coupling failure. During a six week evaporator shutdown, the compressor drive system has been modified to provide additional axial support. The redesign of the drive system necessitated a relocation of the drive motor resulting in interference with piping systems. Piping system redesign and modifications were required and have been completed.

On January 14, 1991, the licensee commenced startup testing of the evaporator using domestic water and will subsequently shift over to AGW. The licensee intends to evaporate and recondense about 15,000 gallons of AGW to ensure that the decontami ation factor is within specification. After this, the licensee intends to send the conc sate to the vaporizer for evaporation of the AGW to environment.

The inspector had no concerns associated with the compressor repair and subsequent restart.

3.0 RADIOLOGICAL CONTROLS

3.1 Routine Radiological Controls

Posting and control of radiation and high radiation areas were inspected. Radiation Work Permit compliance and use of personnel monitoring devices were checked. Conditions of step-off pads, disposal of protective clothing, radiation control job coverage, area monitor operability and calibration (portable and permanent) and personnel frisking were observed on a sampling basis. No noteworthy observations were made.

3.2 Elevated Tritium at MS-1

On December 26, 1990, the resident inspector was notified that elevated levels of tritium had been observed at monitoring well MS-1. Monthly sampling from the well normally shows 150 to 200 pCi/l of tritium (natural background in water). The analysis of December 7, 1990 sample showed 5200 pCi/l, the December 20, 1990 sample showed 17,000 pCi/l, the December 26, 1990 sample showed 12,000 pCi/l and the December 28, 1990 sample showed 10,000 pCi/l. For comparison, the 10 CFR 20 limit for discharges to unrestricted areas is 3 E -3 uCi/ml (3,000,000 pCi/l) and the Environmental Protection Agency safe drinking water standard is 20,000 pCi/l.

Monitoring stations are a series of shallow wells surrounding the TMI-2 reactor building with one control well (MS-1) located away from the reactor building. The groundwater monitoring program originated in 1980 to detect leakage of the 600,000 gallons of water which flooded the TMI-2 reactor building basement after the March 1979 accident. MS-1 is a control well for all the other TMI monitoring wells which means that it is located some distance away from the other wells and is used as a comparison for minor fluctuations in the tritium levels received. MS-1 is about 50 feet deep and is located west of the TMI-1 natural draft cooling towers and north of the plant.

The licensee believes that a Unit-1 secondary side heater draining evolution may be the source of the tritium. Secondary side water contains approximately 2,000,000 pCi/l of tritium caused by minute primary to secondary leakage. On November 28, 1990, tube leaks occurred in the 10th stage feedwater heater. In the process of isolating the heater for repair, it became necessary to drain the "B" 6th stage feedwater heater. Hard pipe drain lines do not exist, so a fire hose was hooked up to provide a drain path. Since the water was hot and pressurized, operations department personnel were concerned with personnel and operational safety and chose to route the fire hose discharge directly to the roof of the intermediate building (outside) where the resulting steam and hot water would not pose a hazard. Within a day or two, the drains, which were no longer pressurized or hot, were redirected to the turbine building sump.

The intermediate building roof drains are directed to yard drains which pass underground and discharge to a surface ditch about 200 feet from MS-1. Therefore, the licensee believed that this secondary water was a potential source of tritium. Samples of water in the drainage ditch show tritium at 380 pCi/l.

The licensee has ruled out the accident generated water (AGW) storage tanks and associated piping as the source of the tritium due to the large distance between MS-1 and the AGW storage tanks and that the underground water tends to flow south-east, which is away from MS-1.

The Plant Review Group met and evaluated the information surrounding this matter. They concluded that although another probable source of tritium was not identified, the PRG was not willing to accept the feedwater heater draining evolution as the source without further investigation. If the heater was the source of the water, the licensee does not believe this is radiological concern because the tritium level (2,000,000 pCi/l) in this water is below the 10 CFR 20 limit for discharge to unrestricted areas (3,000,000 pCi/l). However, for future draining evolutions, the operations department will submit a change modification request to Plant Engineering to evaluate providing other methods of draining.

The inspector reviewed this information and concurred with the PRG that additional evaluation is required to assure that the feedwater heater draining evolution was the source of the tritium. The inspector also concurs that it the feedwater heater was the source of the tritium, this does not pose a radiological concern because tritium levels were below the regulatory limit. The inspector will continue to review licensee actions regarding this matter.

4.0 MAINTENANCE

4.1 Maintenance Observation

The inspector reviewed selected maintenance activities to assure that:

- -- The activity did not violate Technical Specification Limiting Conditions for Operation and that redundant components were operable;
- -- Required approvals and releases had been obtained prior to commencing work;
- -- Procedures used for the task were adequate and work was within the skills of the trade;
- -- Activities were accomplished by qualified personnel;
- -- Where necessary, radiological and fire preventive controls were adequate and implemented;
- -- QC hold points were established where required and observed; and,
- -- Equipment was properly tested and returned to service.

Maintenance activities reviewed included:

- -- Corrective Maintenance Procedure 1420-CRD-4, Reactor Trip Breaker Maintenance to Repair Undervoltage on CB-011. The reactor trip breaker was exchanged for a spare breaker because a humming noise was noted coming from the undervoltage coil. Two potential causes for the humming were identified. Neither of these causes would have prevented proper operation of the reactor trip breaker. This item was inspected on January 3, 1991.
- -- Corrective Maintenance Procedure 1430-Y-35, Troubleshoot and Repair Integrated Control System module 2-2-5 and Integrated Master Circuit Drift Problem. Inspected on January 3, 1991.
- -- Job Order No. 032321, Adjust DC-V-65A Limit Switch. Inspected January 7, 1991.
- -- Job Order No. 033530, Adjust DC-V-65A Limit Switch. Inspected January 8, 1991.

No noteworthy observations were made.

5.0 SECURITY

5.1 Routine Security Observations

Implementation of the Physical Security Plan was observed in the following plant areas:

-- Protected Area and Vital Area barriers were well maintained and not compromised;

-- Isolation zones were clear;

-- Personnel and vehicles entering and packages being delivered to the Protected Area were properly searched and access control was in accordance with approved licensee procedures;

-- Persons granted access to the site were badged to indicate whether they have unescorted access or escorted authorization;

-- Security access controls to Vital Areas were being maintained and that persons in Vital Areas were properly authorized;

-- Security posts were adequately staffed and equipped, security personnel were alert and knowledgeable regarding position requirements, and that written procedures were available; and,

-- Adequate illumination was maintained.

No noteworthy observations were made.

6.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION

6.1 Decay Heat Closed Cooling Water System Operability

On November 17, 1990 the licensee discovered that the normally shut valve, DC-V-65A, was partially open. The Decay Heat River Water System supplies river water to cool the Decay Heat Closed Cooling Water (DHCCW) system (via the Decay Heat Service Coolers) which in turn cools the Decay Heat Removal (DHR) system (via the DHR Coolers). DC-V-65A, which is part of the DHCCW system, is the bypass valve around one of the DHR coolers (DH-C-1A). During normal plant operations, the DHR coolers are used to remove heat from the reactor coolant system when performing a plant cooldown. During a loss of coolant accident, the DHR coolers provide long term core decay heat removal by recirculating reactor coolant from the containment sump back to the reactor vessel.

On November 6, 1990, DC-V-65A was cycled open and shut to test a recent modification to the valve. However, the butterfly valve remained partially open after the test because the

Woodruff key between the valve stem and actuator failed. A subsequent review of the plant computer alarms indicated that DC-V-65A was not on its closed seat. The shift foreman who investigated the alarm did not notice that the valve was partially open. The shift foreman manually manipulated the DC-V-65A limit switch, which is used to indicate when the valve is not fully closed, and the alarm cleared. Based on this, the foreman incorrectly concluded that the limit switch must be out of adjustment. A work order was written to adjust the limit switch.

On November 15, 1990, the limit switch was adjusted and post-maintenance testing was performed which cycled DC-V-65A and ensured that the computer alarm cleared. The exact position of the valve prior to cycling the valve was not observed. On November 17, 1990 a startup and test engineer, who had worked on a recent modification to the valve, noticed that the valve was 15 degrees open.

A test of the DHCCW system was performed to determine how much flow to the DHR cooler was bypassed. The test indicated that the normal 3000 gpm of DHCCW to the DHR cooler was reduced to 1500 gpm. The valve was then closed manually.

A Plant Review Group (PRG) meeting was held on November 19, 1990 to evaluate DHCCW system operability. The PRG requested that technical functions evaluate the relative effects on plant parameters of a large break loss of coolant accident with 1500 gpm DHCCW flow to the DHR coolers versus 3000 gpm. Technical functions provided the following information to the PRG for review.

> After establishing reactor building sump recirculation and with only half the design DHCCW flow to the DHR cooler, the reactor vessel volume liquid temperature heated up an additional 25 degrees F to reach saturation temperature for reactor building pressure (21.6 psia/232 degrees F). Therefore, there would be boiling in the core and boron concentration. Long-term concentration would lead to boron precipitation. The reason for the heatup to saturation is because the reactor coolant system is open to the containment and decay heat produced in the core cannot be matched by 1500 gpm DHCCW for at least seven hours. Temperature and pressure stabilize and decrease because of fan cooler heat removal.
>
> Reactor building sump temperature decreases after establishing sump recirculation; however, with half the DHCCW flow to the DHR cooler, the rate of the temperature drop is 0.11 degrees F/min (6.6 degrees F/hr) vice 0.30 degrees F/min (18 degrees F/hr) at full flow. This does not cause a net positive suction head problem for the pumps taking suction on the reactor building sump.
>
> For the case with half the design DHCCW flow to the DHR cooler, reactor building vapor temperature is 11 degrees F hotter at the seven hour point (24950 sec) into the event. Additionally, reactor building pressure is 1.4 psi higher at that time. These temperatures could exceed the equipment qualification temperatures.

On November 29, 1990, a second PRG meeting was held to discuss the results of the computer analysis. The PRG concluded that the DHCCW system still met its design basis and was operable based on the computer analysis determination that although reactor vessel temperature reaches saturation temperature, the core would still be cooled.

The inspector reviewed the results of the PRG reviews and applicable documents to independently review the licensee's evaluation. The inspector reviewed the sections of the Final Safety Analysis Report which describes the required safety system capabilities for the DHR system. The FSAR defines the required system characteristic needed and verifies by approved accident analysis that the system capabilities are adequate in mitigating the consequences of an accident and ensuring that the 10 CFR 50.46 Emergency Core Cooling System acceptance criteria are met.

If a safety system is in a significantly degraded condition, the licensee has the burden of proving that the accident analysis is still valid and must clearly document the evaluation. The licensee should also document other potential concerns that were addressed by the PRG. By clearly and concisely defining the issues in writing, allows the PRG to focus their attention on these issues and ensures all issues are covered.

The inspector's review of the PRG documentation indicated that the PRG documentation alone was not extensive enough in providing a basis for operability. The inspector verbally obtained much of the information that the PRG considered in determining system operability. Based on the information obtained in these conversations the inspector concurred with the licensee that the DHCCW system was still operable in the degraded condition and that their accident analysis was still valid.

The inspector also noted that the licensee had not considered that the position of DC-V-65A was unknown for nine days (November 6 through November 15, 1990). The licensee evaluation was based on the known position and flow rate through the valve that existed from November 15 to November 17, 1990. After discussing this matter with the licensee, plant engineering evaluated this concern and concluded that the valve was likely to have been open less than 15 degrees during this nine day period. They believe that because of the way the valve failed, each time the valve was stroked it didn't open quite as far or close quite as far. Although there is no way to definitively prove valve position during these nine days, the inspector had no concerns associated with the engineer's logic in coming to his conclusion.

The inspector concluded that the PRG documentation associated with this matter was weak. The documentation alone was not extensive enough to support the licensee decision to declare the DHCCW system operable. In addition, if the documentation had been more extensive this would have clearly and concisely defined the issues and therefore, the licensee may have recognized that the position of DC-V-65A was unknown for nine days.

The inspector also examined the licensee's ability to identify and correct this degraded system condition. It appears that the licensee had a number of opportunities to identify that DC-V-

65A was partially open. For instance, the partially open valve should have been noticed by the shift foreman during his investigation of the computer alarm. Also, this degraded condition should have been noted by the person who adjusted the limit switch due to personnel training or by post-maintenance testing. Finally, the partially open valve should have been noticed by auxiliary operators when conducting routine logs.

The inspector concluded that the licensee appeared to have ample opportunity to identify that DC-V-65A was partially open yet failed to do so. The inspector has not had the opportunity to fully evaluate this matter and therefore is making this an unresolved item. (50-289/90-21-002)

6.2 Diesel Generator "B" Exciter Overvoltage

On December 14, 1990, the exciter overvoltage relay on diesel generator "B" picked up twice during testing of engineered safeguards components per Surveillance Procedure 1303-5.2, Rev.37, "Loading Sequence and Component Test and High Pressure Injection Channel Test." This test performs several fast starts of the diesel under no-load conditions. The exciter overvoltage relay picked up because the auto-voltage adjust rheostat on the inside of the locked local control cabinet was not in the correct position. When the exciter overvoltage relay picks up, the exciter power supply trips resulting in a diesel block alarm in the control room. This protective function is not bypassed during an actual engineered safeguards condition. It is not known why or how long the setting was misadjusted. A possible cause was an accidental bumping of the auto-voltage adjust rheostat during cleaning and inspection of the cabinet during the last diesel overhaul from October 15, 1990 through October 19, 1990.

The same day, the licensee took measurements with a digital voltmeter at the local cabinet to assess the effect and/or damage of this misadjustment on the diesel. They measured voltage at the exciter overvoltage relay with the auto-voltage setpoint at its normal setting and at a lower setting. The licensee did not test the voltage in the as-found misadjusted higher setting for fear of damaging the generator. By measuring voltage at two lower settings, the licensee calculated what the voltage was at the higher setting, thereby eliminating the potential for damaging the generator. The calculation was based on the assumption that there is a linear relationship between the auto-voltage adjust rheostat and the exciter output voltage. Calculations showed that voltage while the setting was misadjusted would have been below the relay setpoint and, therefore, no damage should have occurred to the diesel.

On December 17, 1990, a PRG meeting was held and determined that the diesel was operable during the time of misadjustment. This was based on the fact that the time delay associated with the relay was sufficiently long to allow a satisfactory reading on the frequency meter and the ready to load light. The ready to load light comes on when the diesel is up to rated speed and voltage. If the exciter overvoltage relay picked up, the diesel would not come up to rated voltage. The PRG also noted that a fast start with electrical load on the generator would reduce the voltage and therefore the exciter overvoltage relay would probably not be picked up.

On December 21, 1990, a second PRG meeting was held which confirmed its previous conclusion that diesel generator "B" was operable during the time of misadjustment. This was based on the voltage measurements and calculations which showed that the exciter voltage while the setting was misadjusted was below the exciter overvoltage relay setpoint. This was also based on the fact that the control room operator did not recall receiving a diesel block alarm.

The inspector evaluated the PRG review of this event and had a concern that the diesel was declared operable during the first PRG meeting. The basis for operability that was documented was inconclusive and could not support the operability decision. Discussions with the PRG chairman about this concern indicated that even though the diesel was declared operable, they still believed that this matter required further investigation. This was the reason why the second PRG meeting was held. From additional discussions with PRG members concerning the basis for operability documented for the second PRG meeting, the inspector agreed with the licensee that the basis was adequate in proving diesel operability.

The inspector had an additional concern related to the licensee's ability to idenufy and correct this degraded system condition. The procedure that places the diesel generator in the engineered safeguards condition and the post-maintenance testing procedure of diesel generator "B" after completion of the overhaul did not discover the out-of-specification exciter voltage. The inspector has not had the opportunity to fully evaluate this concern and therefore, is making this an unresolved item. (50-289/90-21-001)

7.0 EXIT MEETING

A summary of inspection findings was further discussed with the licensee at the conclusion of the report period on January 14, 1991. Persons designated with an asterisk in Section 1.3 were present at the exit meeting.