U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 94-02

Docket No. 50-289

License No. DPR-50

Licensee: GPU Nuclear Corporation
P.O. Box 480
Middletown, PA 17057

Facility: Three Mile Island Station, Unit 1

Location: Middletown, Pennsylvania

Inspection Period: January 18, 1994 - February 28, 1994

Inspectors: Michele G. Evans, Senior Resident Inspector
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Approved by: John F. Rogge 3/30/94
John F. Rogge, Chief Date
Reactor Projects Section No. 4B

Inspection Summary

The NRC Staff conducted safety inspections of Unit 1 power operations. The inspectors reviewed plant operations, maintenance, engineering, radiological controls, and security activities as they related to plant safety.

Results: An overview of inspection results is in the executive summary.

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EXECUTIVE SUMMARY

Three Mile Island Nuclear Power Station
Report No. 50-289/94-02

Operations

The licensee conducted overall plant operations in a safe and conservative manner. Operator response to a feedwater transient was very good.

The licensee failed to establish an adequate procedure for draining the reactor coolant system because the operating procedure did not address how to minimize or prevent the spill over of reactor vessel water into the cold legs as the cold legs are drained. As a result, on November 16, 1993, the indicated reactor vessel level on one level transmitter twice dropped below the curve for the minimum height of water required to avoid vortex formation vs. decay heat removal flow. The failure to establish an adequate procedure is a violation of Technical Specification 6.8.1.

Log keeping was inadequate in that an Auxiliary Operator recorded readings for the river water fire service diesel without actually performing the readings. A similar incident occurred in January 1993. The failure to properly record the log readings is a violation of 10 CFR 50.9(a) and Technical Specification 6.8.1.

The licensee is evaluating their longstanding practice of not routinely entering the Technical Specification Limiting Condition for Operations when a surveillance test renders the equipment inoperable. This issue is considered unresolved pending the approval of the necessary Technical Specification changes and the licensee's implementation of the practice of entering the action statements.

Maintenance

Overall, the licensee's conduct of maintenance activities was good. In addition, the licensee's program for the conduct of troubleshooting activities was adequate.

Safety Assessment and Quality Verification

On February 24, 1994, the licensee briefed NRC management on the changes they are considering in their Quality Assurance organization. The NRC will evaluate these proposed changes when the licensee formally submits them to the NRC.

The Plant Review Group effectively performed its role in assuring the safe operation of the facility when they evaluated the acceptability of the request for Enforcement Discretion to delay control rod movement testing. The purpose of the Enforcement Discretion was to minimize all activities that could jeopardize electrical production in response to a declared state of emergency by the Commonwealth of Pennsylvania as a result of extreme cold weather.

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DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

1.1 Licensee Activities

Unit 1 remained at 100% power throughout the inspection period with the exception of February 7, 1994, when the licensee temporarily reduced power to 80% due to a feedwater transient.

1.2 NRC Staff Activities

The inspectors assessed the adequacy of licensee activities for reactor safety, safeguards, and radiation protection, by reviewing information on a sampling basis. The inspectors obtained information through actual observation of licensee activities, interviews with licensee personnel, and documentation reviews.

The inspectors observed licensee activities during both normal and backshift hours: 33 hours of direct inspection were conducted on backshift. The times of backshift inspection were adjusted weekly to assure randomness.

2.0 PLANT OPERATIONS (71707)

2.1 Operational Safety Verification

The inspectors observed overall plant operation and verified that the licensee operated the plant safely and in accordance with procedures and regulatory requirements. The inspectors conducted regular tours of the following plant areas:

--Control Room
--Switch Gear Areas
--Access Control Points
--Protected Area Fence Line
--Fuel Handling Building
--Auxiliary Building
--Turbine Building
--Intake Structure
--Intermediate Building
--Diesel Generator Building

The inspectors observed plant conditions through control room tours to verify proper alignment of engineered safety features and compliance with Technical Specifications. The inspectors reviewed facility records and logs to determine if entries were accurate and identified equipment status or deficiencies. The inspectors conducted detailed walkdowns of accessible areas to inspect major components and systems for leakage, proper alignment, and any general condition that might prevent fulfillment of their safety function.

On February 7, 1994, a feedwater transient occurred while placing a condensate demineralizer vessel in service. Control Room Operators quickly reduced reactor power to 80% in response to the reduction in feedwater flow. The inspector reviewed the licensee's corrective actions to prevent recurrence and found them to be acceptable. Operator response to the transient was very good.

The inspector concluded that the licensee conducted overall plant operations in a safe and conservative manner. However, there were several concerns associated with draining the reactor coolant system and log keeping by Auxiliary Operators that are described below.

2.2 Reactor Coolant System Drain Down (Violation 50-289/94-02-01)

On November 15 and 16, 1993, the licensee partially drained the reactor coolant system (RCS) per Operating Procedure 1103-11, "Draining and Nitrogen Blanketing of the Reactor Coolant System," to support the repair of a leaking thermowell in the 'C' RCS cold leg. The inspector reviewed this drain down evolution and had numerous concerns. The RCS is drained by using the reactor coolant (RC) drain pump (WDL-P-16), which can take suction off all four cold leg low points and discharges to one of three reactor coolant bleed tanks. The licensee did not provide nitrogen blanketing for the RCS during the drain down so they vented the RCS through the reactor coolant drain tank. There are two reactor vessel level transmitters, LT-1037 and LT-1138 whose range is 0-120" above the cold leg centerline. The licensee also installed a tygon standpipe on the same line as LT-1037 and LT-1138 to provide redundant reactor vessel level indication. These standpipes were monitored in the control room by a camera. There is also a tygon standpipe on the 'B' and 'C' cold legs to measure cold leg levels. During this drain down the RCS was vented through a primary hand hole on each hot leg, one control rod drive vent, and a vent on each of the four reactor coolant pump (RCP) seal assemblies. The decay heat removal (DHR) pumps take suction off the bottom of the hot leg near the reactor vessel and discharges to the core flood nozzle. The incore thermocouple temperatures were maintained between 119°F and 127°F during the drain down.

On November 15, 1993, at 5:58 p.m., the licensee started draining the RCS to the 'B' reactor coolant bleed tank. Step 4 of section 3.3.2 states that when pressurizer level reaches <u>approximately 184"</u>, open CRD vent(s) of at least one of the highest CRDs as directed by the Plant Operations Director with due consideration for Limitations and Precaution step 2.1.7. [One hundred and eighty four inches in the pressurizer is below the level of the CRD vents and therefore water will not come out the vent and air enters the reactor head as RCS level is lowered further.] The inspector identified two concerns with the implementation of this step. The first concern is that the licensee did not open a CRD vent until <u>reactor vessel level</u> (LT-1037 and LT-1138) was at approximately 22" (reactor vessel level reads 7 7/8 inches lower than pressurizer level) because Plant Maintenance was initially unable to find the CRD vent tool. LT-1037 and LT-1138 were placed in service at approximately 110". The Shift Supervisor told the Plant Operations Director that he was in the process of draining below 184" without the vent open and that he planned to stop the drain down and open the vent at

110" when LT-1037 and LT-1138 were placed in service. However, this was not done and by the time the venting tool was found and personnel entered the reactor building, the CRD vent was not opened until reactor vessel level was 22". As described below, insufficient venting of the reactor vessel will cause LT-1037 and LT-1138 to indicate low with respect to actual reactor vessel level. It is uncertain to what extent the delay in opening the vent had on reactor vessel level indications or whether the delay may have caused confusion in interpreting the level indications later in the drain down. Administrative Procedure (AP) 1001G, "Procedure Utilization," step 4.1.2, states that personnel shall not give directions, guidance, recommendations or clarifications which conflict with approved procedures. Therefore, the inspector determined that a Temporary Change Notice should have been written to drain below 184" in the pressurizer without opening the CRD vent.

The inspectors second concern with the implementation of step 4 of section 3.3.2 is related to Limits and Precautions step 2.1.7, which provides the minimum RCS venting area relative to time after shutdown in order to prevent an RCS pressurization of greater than 5 psig following a total loss of DHR and potential RCS steam production. For a time after shutdown of 24 hours, the required venting area is 61.1 in^2. Generic Letter 88-17, "Loss of Decay Heat Removal," describes how an RCS pressurization could prevent the gravity drain of borated water storage tank (BWST) water to the RCS. The licensee prepared Temporary Change Notice (TCN) 1-93-0113 to change step 2.1.7 to reduce the venting to two primary hand holes which have a total area of 39.2 in^2. In the Safety Evaluation for the TCN the licensee stated that the reduction in venting area is safe since redundant methods of core cooling (high pressure injection pump) are maintained available. However in the licensee's response to Generic Letter 88-17, item 3, the licensee stated that they will maintain an adequate RCS venting area during a drained down condition to preclude the need for high pressure injection (HPI) capability. The licensee stated that the reasoning behind this commitment was that they did not want to commit to maintaining HPI available during refueling outages, so by maintaining the venting area, they would not loose the ability to gravity drain to the RCS. The inspector determined that although the licensee did not meet the Generic Letter commitment, the licensee still maintained sufficient injection capability.

A partial vacuum normally develops in the reactor vessel head, and possibly the hot legs, because the RCS can be drained faster than it can vent. In the licensee's response to Generic Letter 87-12, "Loss of Residual Heat Removal While the RCS is Partially Filled," item 5, the licensee stated that since the fixed reference leg for LT-1037 (LT-1138 was not installed at the time) is vented back to the RCS, the transmitter will correctly sense level during varying conditions of nitrogen overpressure and partial vacuum developed during the drain down. However, since OP 1103-11, step 6 of section 3.3.2 aligns the reference legs for LT-1037 and LT-1138 to the 'A' hot leg, and since the 'A' hot leg is at reactor building pressure and the reactor vessel at a partial vacuum, the indicated reactor vessel level reads 5 to 6 inches or more lower than actual level during the drain down. The indicated reactor vessel level slowly increases when the drain down pump is secured as the reactor vessel pressure increases to reactor building pressure. This lower indicated level is conservative in that it is better for the instrument to read lower rather than higher than actual level during the drain down. The inspector noted that the reference leg for LT-1037 can be aligned to the reactor vessel. The licensee agreed to evaluate if aligning this reference leg to the reactor vessel would minimize the level error caused by the partial vacuum without causing LT-1037 to read higher than actual level.

The centerline of the RCPs is 42 inches above the center line of the cold leg nozzles (cold leg center line is 0" on LT-1037 and LT-1138.) Even though the RCP is higher, as the cold legs are drained below the level of the RCPs, water spills over from the reactor vessel into the cold legs. OP 1103-11, step 2.3.5, states that for a reactor coolant temperature detector removal in the cold legs, reactor vessel level will be held at 18" $\pm$ 2". During this drain down, the reactor vessel level decreased to 13.1" due to the spill over of water. Although this spill over occurs to varying degrees each time the RCS is drained, it is not mentioned in OP 1103-11. The licensee stated that it is not uncommon for reactor vessel level to drop to 10" to 13" due to the spill over. The licensee has a vent installed on each RCP seal package to try to minimize this spill over. OP 1103-11, step 2.1.4 states that the maximum permissible decay heat removal (DHR) flow is governed by the Figure 10 graph, "Minimum Height of Water Required to Avoid Vortex Formation versus Decay Heat Flow." Vortexing at the junction of the DHR system suction line and the RCS can occur if water level is to low, which may introduce air into the DHR suction and could perturb DHR system operation. Since operators were aware that the spill over from the reactor vessel to the cold leg occurs, they reduced DHR flow prior to this point to remain above the vortex curve. During the drain down on November 16, the operators thought they reached the point where only the cold legs were draining because reactor vessel remained steady at 18", so they did not expect a further reduction in reactor vessel level. Based on this, the operators increased DHR flow from 1500 gpm to 2000 gpm. The operators continued to operate the RC drain pump until they realized that there was a larger increase in reactor coolant bleed tank volume compared to the decrease in cold leg level. At that time, the operators secured the RC drain pump. The licensee found that there was a kink in the 'B' RCP seal cavity vent which they thought caused the discrepancy in levels. The operators then restarted the RC drain pump. When LT-1037 started to decrease to 13.1" the operators realized they had not reached the point where the reactor vessel no longer drained. The operators then reduced DHR flow back to 1500 gpm, but not before LT-1037 indicated that level was below the vortex curve by a maximum of 0.96 inches for approximately 2 minutes. With DHR flow at 1500 gpm, the RCS temperature began to increase so they added 542 gallons to the reactor vessel to return the level to approximately 18" so they could increase DHR flow back to 2000 gpm and remain above the vortex curve. RCS temperature increased from 119°F to 126°F in approximately 10 minutes and then temperature remained constant at 126°F. As the operators continued to operate the RC drain pump, LT-1037 again started to decrease to 13". The operators again reduced DHR flow to 1500 gpm, but not before LT-1037 indicated that level was below the vortex curve by a maximum of 1.66" for 5.5 minutes.

Although the indicated level on LT-1037 showed that reactor vessel level went below the vortex curve, actual reactor vessel may not have dropped below the vortex curve for the following reasons: 1) LT-1138, which was indicating approximately 2" higher than LT-

1037, did not go below the vortex curve. 2) Prior to going below the vortex curve, the tygon tubing that was attached on the same line as LT-1037 would only intermittently pass flow so the licensee thought there may be a piece of debris at the isolation valve for the tygon. An operator hit the isolation valve with a wrench to try to dislodge the debris and the vibration caused LT-1037 to permanently drop by approximately 1.5 inches. The operators were unaware of this level drop. The licensee could not get the tygon standpipe filled and therefore it was not placed in service. 3) As described above, the partial vacuum in the reactor vessel causes LT-1037 to read low. Regardless of whether <u>actual</u> reactor vessel level went below the vortex curve, the operators correctly took actions based on the <u>indicated</u> reactor vessel level. The inspector determined that the licensee's performance was weak in that they did not identify themselves that the indicated level on LT-1037 went below the vortex curve.

The vortexing graph was based on actual test results that were verified by the licensee in 1973. There is no margin of safety included in the graph and there is no allowance made for instrument errors. In the licensee's 1973 test, while monitoring DHR motor amperage and listening for DHR pump vortexing, the licensee lowered RCS level to confirm that the vortex curve was the actual point that DHR pump vortexing began to occur. Since the plant computer does not record DHR pump amperage or DHR discharge pressure and nobody was at the DHR pump listening for vortexing on November 16, 1993, these indications cannot be reviewed to determine if vortexing occurred. There was no alarm for DHR pump vibration on November 16 and there was no unusual fluctuations in DHR flow (which is recorded by the plant computer.) In addition, plant operators do not recall seeing any abnormalities in indications. These indications show that it is unlikely that actual reactor vessel level went below the vortexing curve and it is unlikely that vortexing occurred.

The licensee has two computer alarms associated with the margin to vortex and each of these alarms have two setpoints (one closer and one further away from the curve.) One alarm is to alert operators that DHR flow is nearing the vortex curve and the other is to alert operators that reactor vessel level is nearing the vortex curve. The inspector reviewed the alarm printout for November 16 and found that there were no margin to vortexing alarms. These alarms should have come in when they first went below the vortex curve and should have cleared and come in again the second time they went below the curve. The licensee agreed to evaluate why the alarms did not come in.

The inspector questioned the licensee why the vortex curve does not account for the instrument error on LT-1037 and LT-1138 by shifting the vortex curve accordingly. The licensee determined that the instrument error is ± 1.34". The licensee agreed to evaluate whether this instrument error should be accounted for.

This incident reflects a weakness in the licensee's control of reactor vessel level during the drain down. The inspector concluded that OP 1103-11 was inadequate in that it failed to address the spill over of reactor vessel water into the cold legs and how to minimize or prevent this spill over from affecting reactor vessel level. This is a violation of Technical

Specification 6.8.1, which requires procedures to be established to control the draining evolution. As part of the response to the violation, the licensee is requested to address why there were no margin to vortexing computer alarms, whether venting the reference leg for LT-1037 to the reactor vessel would minimize the level indication error and whether the instrument error for reactor vessel level indication should be accounted for in the vortex graph. **(50-289/94-02-01)**

2.3 Auxiliary Operator Log Keeping (Violation 50-289/94-02-02)

On January 27, 1994, Operation's management noted that the Outbuildings Tour Log completed by the Auxiliary Operator (AO) on the 3 p.m. to 11 p.m. shift had a note that the AO was unable to enter the River Water Fire Service Diesel Building because of a frozen door lock. The River Water Fire Service Diesel Building is a locked building with keys controlled by the Operations and Security Departments. The fire service diesel water pump located in this building, pumps water from the Susquehanna River to the fire main serving the main portion of the plant. There are two readings on the Outbuildings Tour Log, the fire service diesel radiator water level check and the fire service diesel fuel oil level, that must be read inside the River Water Fire Service Diesel Building. The AO from the previous shift (7 a.m. to 3 p.m.) had recorded these two readings in the log. When this AO was questioned about the frozen lock, the AO stated that he recorded the two readings but had not entered the River Water Fire Service Diesel Building. The AO stated that he recorded the two fire service diesel log readings while in the TMI-1 River Water Pump House, which is located adjacent to the River Water Fire Service Diesel Building. The AO said that he fully intended to confirm the readings, but he became busy with other jobs and was never able to enter the River Water Fire Service Diesel Building. The AO stated the he knew it was not an acceptable practice to record readings without first viewing the instrumentation and that he had not previously recorded readings in this manner.

To evaluate whether this was an isolated discrepancy for the AO, the licensee reviewed all of the AO Outbuildings Tour Logs, Primary AO Tour Logs and Secondary AO Tour Logs completed by the AO during November and December 1993, and January 1994. By reviewing the vital and protected area key card access system history, the licensee was able to verify if the AO entered these areas to record the log readings. Since the River Water Fire Service Diesel Building does not have a key card access, the licensee could not verify that the AO had taken the associated readings properly in the past for this area. The licensee did not find any additional anomalies with the AO's log keeping practices for the areas that required key card access. The licensee also reviewed training records and verified that the AO had received training on January 4, 1993, which covered falsification of plant records. This training discussed that it was unacceptable to prerecord data prior to observing it.

As a corrective action, on February 3, 1994, the licensee took disciplinary action against the AO. In addition, during the period of February 14 through March 8, 1994, the Operation's Director met with all AOs and each operating crew to inform them of the incident and counsel them on the importance of proper log keeping.

The inspector reviewed the licensee's investigation report of this incident and found it to be thorough. The AO's actions of prerecording this data was not in compliance with TMI-1 Administrative Procedure (AP) 1016, " Operations Surveillance Program," Section 4.1.2.1a, step 5. This section reads, "Information should be recorded on the log concurrently with when it is obtained. In no case shall information be entered prior to or in anticipation of the observation or event." The inspector reviewed training records and verified that all AOs had received the training covering falsification of plant records and AP 1016. In addition, the inspector interviewed several AOs and noted a heightened awareness to the requirement to confirm readings prior to recording them in the logs.

The inspector concluded that the safety significance of the AO's actions were minimal since there were two other fire service pumps available to supply water to the fire main. However, the AO's entering of readings for the River Water Fire Service Diesel radiator water level and fuel oil level without first observing and verifying the readings is a violation of 10 CFR 50.9(a) which requires that information required by statute or by the Commission's regulations shall be complete and accurate in all material respects. **(50-289/94-02-02)**

2.4 Entering the Technical Specification Limiting Condition for Operations During Surveillance Testing (Unresolved Item 50-289/94-02-03)

Prompted by an NRC concern at another facility, the licensee began to evaluate their practice of not routinely entering Technical Specification (TS) Limiting Conditions for Operation (LCOs) when the performance of a surveillance test renders equipment inoperable. This practice is contrary to the guidance provided in NRC Generic Letter (GL) 91-18, entitled "Information to Licensees Regarding Two NRC Inspection Manual Sections on Resolution of Degrading and Nonconforming Conditions and Operability," which states that, unless specifically prohibited otherwise, the TS LCO statement shall be entered when equipment is removed from service and rendered incapable of performing its safety function. This practice of not entering the TS LCOs could be a safety concern because compensatory actions required when a safety system function is inhibited may not be implemented, and TS-required equipment may be left inoperable for greater than the allowed outage time. In addition, operators may unknowingly allow both trains of redundant TS-required equipment to be rendered inoperable by allowing LCO-required maintenance to be performed on one train while a surveillance test inhibits the system safety function on the other train.

On January 18, 1994 the Plant Review Group (PRG) met to address this issue. The PRG noted that in the past, TMI operations has declared components/systems inoperable during surveillances only when the component/system is clearly inoperable (e.g. annual emergency diesel overhaul, radiation monitoring system calibration, etc.). The PRG believed this was common to older plants with custom TS, since the TS would not otherwise allow performance of the surveillances in some cases (e.g. requiring testing of a redundant component.)

After several PRG meetings, the licensee identified a list of surveillances in which components could be considered inoperable, but TS LCOs were not entered. In addition, the PRG identified the TSs which would not allow performance of the surveillances if the equipment was considered inoperable. The licensee identified the Technical Specification Change Requests (TSCR) that were needed to implement the practice of entering the TS LCOs. The licensee determined that TSCRs are necessary for protection system instrumentation, emergency diesel generator testing, emergency feedwater testing and containment isolation valve testing. The licensee has prepared and submitted two TSCR packages to the NRC and is currently finalizing a third TSCR package. The licensee stated that they would implement this new practice approximately 30 days after issuance of all the necessary TS amendments. The 30 days will allow time for implementation of procedure changes and for training of Operations personnel. The issue is considered unresolved pending approval of the TSCRs and inspector review of the licensee's implementation of this change in practice. Although the licensee should have evaluated their practice of not entering TS LCOs when the performance of a surveillance test rendered the equipment inoperable upon issuance of GL 91-18, the inspector found that the actions that the licensee is currently taking to comply with the guidance in the GL were appropriate. **(50-289/94-02-03)**

3.0 MAINTENANCE (61726, 62703, 71707)

3.1 Maintenance Observations

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; maintenance technicians were properly qualified; radiological and fire prevention controls were adequate; and, equipment was properly tested and returned to service.

Maintenance activities reviewed included:

- Job Order No. 81234, "Radiation Monitor Tie-in to Plant Computer."
- Preventive Maintenance Procedure E-107, "Conduct of Infrared Thermography," on the 'A' emergency diesel generator.
- Job Order No. 83941, "'A' Reactor Protection System Channel T Hot Module Failed Offscale High."

- Corrective Maintenance Procedure 1420-Y-13, "General Circuit Troubleshooting and Repair."

The inspector found that the overall conduct of the above maintenance activities was good.

3.2 Troubleshooting

The inspector conducted an overall review of the manner in which the licensee conducts troubleshooting activities. Plant Maintenance, Plant Operations, Plant Engineering, and Startup and Testing can all be involved in troubleshooting activities. The licensee does not have an administrative procedure that discusses the overall controls used when troubleshooting and therefore there is no procedure that specifically identifies who has the lead responsibility for troubleshooting. AP 1001G, "Procedure Utilization," step 4.19, provides administrative controls for the performance of evolutions not covered by a procedure, which includes some troubleshooting activities. The procedure states that skills normally possessed by qualified station personnel may not require detailed step-by-step delineation in a written procedure. Personnel performing evolutions not covered by written procedures shall comply with general administrative procedural controls that govern or define the following areas: 1) obtaining permission and clearance from operations personnel to work and for logging such work; 2) maintaining occupational radiation exposure as low as reasonable achievable; 3) identifying what procedures are necessary for the maintenance activity; 4) identifying post maintenance testing including system/equipment functional capability to meet operational requirements in all respects; 5) ensuring that maintenance activities are properly reviewed, and; 6) ensuring the individual performing the task possesses the required skill to do the task as determined by the Shift Supervisor or a Station Manager/Director.

The licensee has several corrective maintenance procedures (CMPs) that are used to troubleshoot specific components such as the emergency diesel generators, control rod drives, the engineered safeguards actuation system, and the power operated relief valve. Troubleshooting activities for I&C frequently involves a specific instrument and the problem is identified and corrected by using the applicable surveillance procedure. There are no CMPs that perform troubleshooting of mechanical systems because this generally involves operating a component, which is done by Plant Operations in accordance with the applicable operating procedure. If there are no specific written instructions that currently exist to perform the necessary troubleshooting, the licensee does not normally prepare a specific procedure but instead relies on the "skill of the trade." When there are no specific instructions for electrical troubleshooting, the licensee generally references CMP 1420-Y-13, "General Circuit Troubleshooting and Repair," which is a general procedure that discusses the administrative controls used for troubleshooting of electrical circuits. The Job Ticket that is generated for the troubleshooting is processed through the control room just like any other maintenance activity. The Shift Supervisor establishes the boundaries and limitations and provides the authorization to perform the troubleshooting. When the licensee finds the component that is causing the problem, the licensee uses the specific CMP for that component to make the repair.

The inspector reviewed all of the CMPs that perform troubleshooting of specific components and found that the detail and quality of the procedures was very good in that: they have a limitations and precautions section, as well as specific notes and cautions in the body of the procedure to prevent personnel injury or plant upsets; they specify the plant status and require Shift Supervisor provide limitations and work boundaries and give permission to start the troubleshooting; they provide specific acceptance criteria and require the as-found condition to be recorded in machinery history; they have an enclosure to keep track of lifted leads, open links, removed fuses, repositioned switches, and mechanical modifications, and; they have a prerequisite to verify that the test equipment used is within it current calibration period. The licensee's tool room keeps track of each maintenance activity that a specific piece of test equipment is used. If during the troubleshooting, the licensee needed to change the work instructions, they would prepare a Temporary Change Notice (TCN) in accordance with AP 1001A, "Procedure Review and Approval." The licensee prepared the troubleshooting procedures in accordance with the Procedure Writers Guide, which was written using industry guidance.

During the last three years there was one incident that was reviewed by the NRC where troubleshooting was a causal factor. In November 1992, the licensee manipulated fire service system valves to locate a small leak. The licensee inadvertently left the station blackout diesel cooling water outlet valve (which is a fire service system valve) closed. This rendered the diesel inoperable for one month. The Shift Supervisor logged some but not all of the fire service valves that were closed to support the troubleshooting. The cooling water outlet valve was not logged and therefore was not returned to its normally open position.

As discussed in Inspection Report 50-289/93-13, on June 10, 1993, the inspector observed the performance of troubleshooting associated with the troubleshooting of emergency diesel generator electrical protective circuitry. The inspector found that there was good coordination between Operations, Maintenance and Engineering and the overall conduct of the troubleshooting was excellent.

The inspector concluded that overall, the licensee's controls for the conduct of troubleshooting are adequate.

3.3 Surveillance Observations

The inspectors observed conduct of surveillance tests to verify that approved procedures were being used, test instrumentation was calibrated, qualified personnel were performing the tests, and test acceptance criteria were met. The inspectors verified that the surveillance tests had been properly scheduled and approved by shift supervision prior to performance, control room operators were knowledgeable about testing in progress, and redundant systems or components were available for service as required. The inspectors routinely verified adequate performance of daily surveillance tests including instrument channel checks and reactor coolant system leakage measurement.

Surveillance activities reviewed included:

- Surveillance Procedure 1302-3.1 "Radiation Monitoring System Calibration."
- Surveillance Procedure 1303-3.1, "Control Rod Movement."
- Surveillance Procedure 1302-3.1B, "RM-L-6 and RM-L-7 Liquid Monitor Calibration."
- Surveillance Procedure 1303-12.14, "Fire Protection Instrumentation Non-Supervised Circuit Test."

The inspectors found that the overall conduct of the above surveillances was good.

3.4 Enforcement Discretion to Delay the Control Rod Movement Surveillance Test

On January 20, 1994, the licensee orally requested Enforcement Discretion from the Technical Specification (TS) 4.1.2 (Table 4.1-2, Item 2) requirement to conduct the control rod movement surveillance test (Surveillance Procedure 1303-3.1 "Control Rod Movement"). The purpose of the Enforcement Discretion was to minimize all activities that could jeopardize electrical production in response to a declared state of emergency by the Commonwealth of Pennsylvania. The state of emergency was declared as a result of greater electrical demands caused by extreme cold weather. NRC Region I orally granted enforcement discretion to exceed the surveillance time interval for TS 4.1.2 (Table 4.1-2, Item 2), from 11:00 a.m. on January 23, 1994 to 11:00 a.m. on January 28, 1994.

The licensee's oral request was followed up by a written letter dated January 21, 1994. As justification for the enforcement discretion, the licensee stated that 1) the control rod mechanism surveillance test has been successfully performed in accordance with the required surveillance interval since the plant returned to power after the 10R refueling outage; 2) the bi-weekly surveillance interval is conservative when compared to the 92-day surveillance interval specified in the standard Technical Specification for B&W plants; and 3) during the period for which enforcement discretion was requested, the reliability of the control rod mechanism can be assured by monitoring other available indicators of control rod performance that are obtained from other Technical Specification required surveillance activities and from plant instrumentation such as the asymmetric rod position indicator alarm.

Based on the review of the basis for the licensee's request, the NRC concluded that: 1) The safety significance of postponing the performance of the surveillance is minimal due to the short duration of the extension (5 days), and; 2) The reliability of the control rod mechanisms has been demonstrated by the successful performance of the surveillance since the 10R refueling outage which ended in October, 1993. The licensee successfully completed the control rod movement test on January 23, 1994 at 12:20 p.m..

The inspector attended the Plant Review Group (PRG) meeting where the Enforcement Discretion was discussed and concluded that the PRG effectively performed its role on assuring the safe operation of the facility. The PRG's discussions and evaluation of the acceptability of delaying the surveillance was good.

4.0 ENGINEERING (40500)

4.1 Reactor Coolant System Thermowell Design

While evaluating a modification to the reactor coolant system (RCS) thermowells, the licensee found that the thermowell design that is currently installed exceeds the allowable shear stress of ASME B31.7 and ASME Code Section III. The licensee made a Emergency Notification System notification in accordance with 10 CFR 50.72(b)(1)(ii)(B), as condition during operation that results in the power plant being outside the design basis of the plant. The licensee calculated the shear stress to be 14,180 psi at an RCS pressure of 2750 psi (maximum accident pressure) and the ASME allowable shear stress is 10,410 psi. The design also exceeds the allowable sheer stress at 2155 psi (normal operating pressure), which will result in the plastic flow of the thermowell material. The licensee determined that the thermowells are still operable because the ultimate shear stress for this material is 34,216 psi based on ASME Section III Appendix I, and therefore a breach or failure of the material is not expected. The NRC has reviewed GPUN's calculations and agrees that plastic flow will occur, which may result in thermowell leakage, but the material is not expected to fail and therefore the licensee's operability determination is acceptable. This issue is still being evaluated by the NRC and licensee and will be discussed further in the next inspection report.

5.0 PLANT SUPPORT (71707)

5.1 Radiological Controls

The inspectors examined work in progress to verify proper implementation of health physics (HP) procedures and controls. The inspectors monitored ALARA implementation, dosimetry and badging, protective clothing use, radiation surveys, radiation protection instrument use, and handling of potentially contaminated equipment and materials. In addition, the inspectors observed personnel working in RWP areas and verified compliance with RWP requirements. During routine tours, the inspectors verified a sampling of high radiation area doors to be locked as required.

The inspector found that overall radiological controls were good.

5.2 Security

The inspectors monitored security activities for compliance with the accepted Security Plan and associated implementing procedures. The inspectors observed security staffing, operation of the Central and Secondary Alarm Stations, and licensee checks of vehicles, detection and assessment aids, and vital area access to verify proper control. On each shift, the inspectors observed protected area access control and badging procedures. In addition, the inspectors routinely inspected protected and vital area barriers, compensatory measures, and escort procedures.

The inspectors found that overall Security Plan implementation was good.

6.0 NRC MANAGEMENT MEETINGS AND OTHER ACTIVITIES

6.1 Routine Meetings

At periodic intervals during this inspection, meetings were held with senior plant management to discuss licensee activities and areas of concern to the inspectors. At the conclusion of the reporting period, the resident inspector staff conducted an exit meeting with licensee management summarizing inspection activities and findings for this report period. Licensee comments concerning the issues in this report were documented in the applicable report section. No proprietary information was identified as being included in the report.

6.2 Quality Assurance Organization Briefing

On February 24, 1994, the licensee briefed NRC management on the changes they are considering in their Quality Assurance organization. The NRC will evaluate these proposed changes when the licensee formally submits them to the NRC. The licensee's slide presentation is provided as an attachment to this inspection report.

GPU NUCLEAR OVERSIGHT
CONSOLIDATION PLAN

I. <u>INTRODUCTION</u>

a) CURRENT QA AND ISR ORGANIZATION

II. <u>GENESIS FOR CHANGE</u>

a) OVERLAPPING AND MULTIPLE OVERSIGHT ORGANIZATIONS

b) DESIRE TO BE BOTH EFFECTIVE AND EFFICIENT

c) KNOWLEDGE OF OTHER LICENSEE EFFORTS

d) DEVELOPED AND USED GUIDING PRINCIPLES

III. <u>PROPOSED REORGANIZATION</u>

a) FUNCTION PERFORMED BY THE QA DEPARTMENT BEFORE AND AFTER REORGANIZATION

b) ASSESSMENT/OVERSIGHT CONSOLIDATION

c) QUALITY VERIFICATION, NDE/ISI AND PROCUREMENT QA

d) BENEFITS

IV. <u>LICENSING ISSUES</u>

a) QA PLAN CHANGE

b) 50.54 ASSESSMENT

V. <u>SCHEDULE</u>

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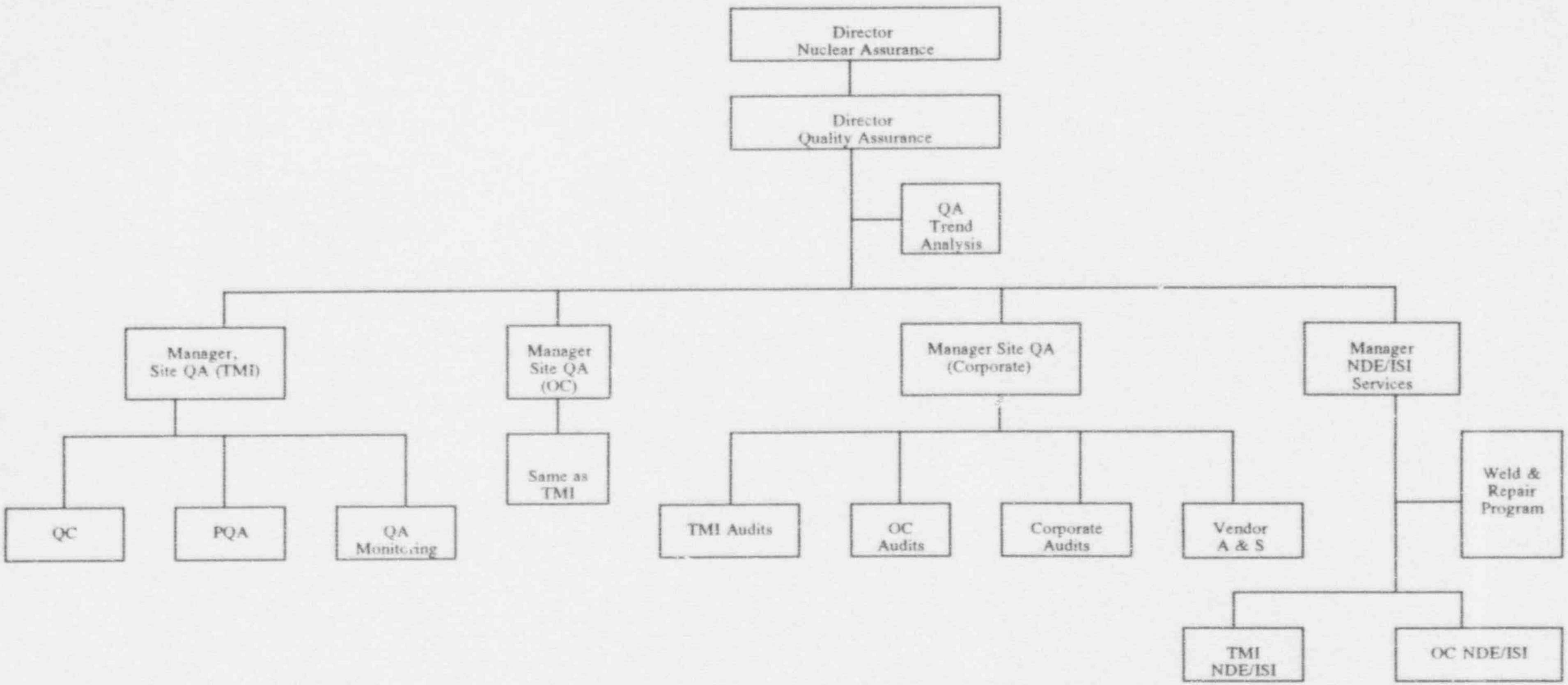

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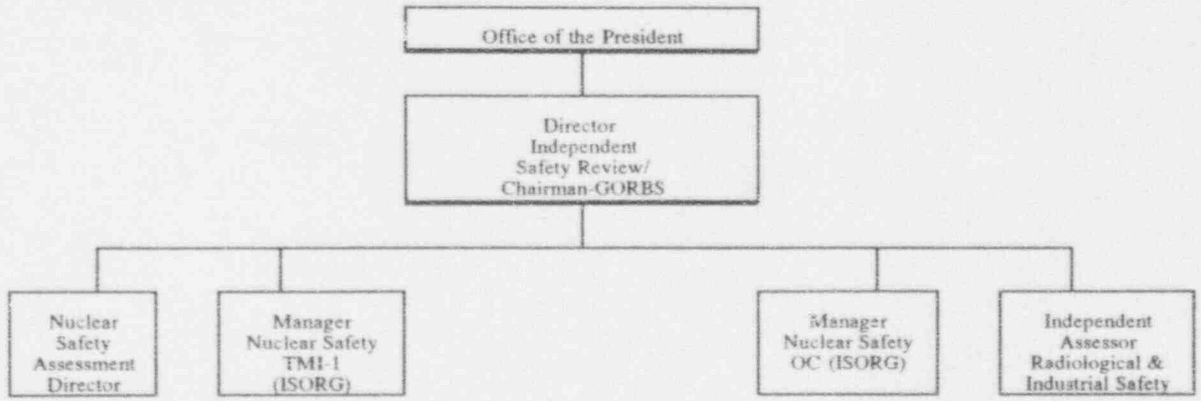

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Purpose: To contribute to a reduction in GPUN power production costs.

Guiding Principles

1. Retain the present philosophy of having an independent safety oversight function which incorporates the GORB and reports to the President/CEO GPUN.

2. Continue to meet all regulations.

3. All regulatory commitments will be met or modified.

4. All current responsibilities/major functions define in the GPUN Organization Plan will continue to be met or modified. A single organization responsible for assessment will be developed.

5. Organizational groupings will be designed to maximize the synergy among different work groups.

6. The level of safety and quality will not be reduced.

7. The costs associated with assessment will be reduced to the degree possible.

8. Staffing levels will be determined by the above principles and consistent with the corporate goal on involuntary separations.

9. Primary responsibility for safety and quality continues with the line organizations.

10. Continue to support GPU System companies with assessment, inspection, NDE and welding expertise.

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QA Responsibilities Matrix

	Responsible Organization
General Functions	
• Stop Work Authority	Assessment/QV
• Unit Shutdown Recommendation	Director Assessment
• QA Plan Interpretations	Director Assessment
PQA Functions	
• Receipt Inspection Planning	Procurement Engineering
• Procurement Document Reviews - Purchase Req's. - Contracts - Procurement Specs	Procurement Engineering
• Receipt Inspection	Procurement Engineering
• Commercial Grade Dedication	Procurement Engineering
• MNCR/RDN Administrations (See Note 2)	Procurement Engineering
• Procedure Reviews - Site Admin. - Warehousing	Procurement Engineering
• Inspector Certification	Procurement Engineering
• Inspection Equipment Maintenance & Calibration	Procurement Engineering
QC Functions	
• Inspection Equipment Maintenance & Calibration	Plant Maintenance (See Note 7)
• Inspection Planning	Plant Maintenance
• MNCR Admin. (See Note 2)	Plant Maintenance

QA Responsibilities Matrix

	Responsible Organization
• Design Package Reviews (See Note 4)	Plant Maintenance
• Procedure Reviews - Site Admin. - Contractor Site Procedures	Plant Maintenance
• ANI Notifications	Plant Maintenance
• Inspection - Maintenance - Modifications	Plant Maintenance
• Weld Program Admin. - Qualified Welder List - Weld Maps - Weld History Records	NDE/ISI
• Inspection Services Contract Admin.	Plant Maintenance
• Inspector Certifications	Plant Maintenance
• Represent QA At Coordination Meetings (See Note 5)	Plant Maintenance
OQA Functions	
• Monitoring	Assessment
• QDR Procedure Ownership	Assessment
• QDR Admin. (See Note 2)	Assessment
• Procedure Reviews	Assessment
• Special Assessments	Assessment
• Monitor Certifications (See Note 6)	Assessment
• Follow-up on Significant DVRs (OC)	Assessment

QA Responsibilities Matrix

	Responsible Organization
Audits	
• Internal Audits	Assessment
• External Service Audits	Assessment
• External Hardware Surveys	Assessment
• External Source Inspection	Assessment
• QA Plan Maintenance	Assessment
• CMAP Coordination	Assessment
• Auditor Certifications	Assessment
• SQCL Maintenance	Assessment
• SCAR Admin.	Assessment
NDE/ISI	
• Inspection Equipment Maintenance & Calibration	NDE/ISI
• ISI Planning	NDE/ISI
• Procurement of Equipment	NDE/ISI
• ISI	NDE/ISI
• ANI Contract Admin.	NDE/ISI
• ANI Notification	NDE/ISI
• Fossil Support	NDE/ISI
• Repair Program Admin.	NDE/ISI
• NDE Support	NDE/ISI
• Weld Program	NDE/ISI
• NDE Services Contract Admin.	NDE/ISI
• Inspector Certifications	NDE/ISI

QA Responsibilities Matrix

	Responsible Organization
Staff Admin.	
• Trending of QA Data (See Note 1)	Assessment
• Computerization of QA Dept.	Assessment
• Special Projects (e.g. Reading Lab)	Assessment
• QA Procedure Maintenance	Assessment
• Annual Assessment Coordination (See Note 3)	Assessment
• Safety Review Coordination for NAD	Nuclear Assurance

Note 1 - Trending of results of assessments, audits, deficiencies will be needed. QA System (QAMIS) could be deleted and other systems used (e.g. Deviation Report Data Base, OC).

Note 2 - MNCR/QDR programs could be deleted at OC and replaced by the Deviation Report. Some modification to OC procedure 104 would be required. TMI would still need them both. The RDN Program should be expanded so that hardware deficiencies on incoming material could also be listed. This would eliminate the need for MNCRs in Receipt Inspection.

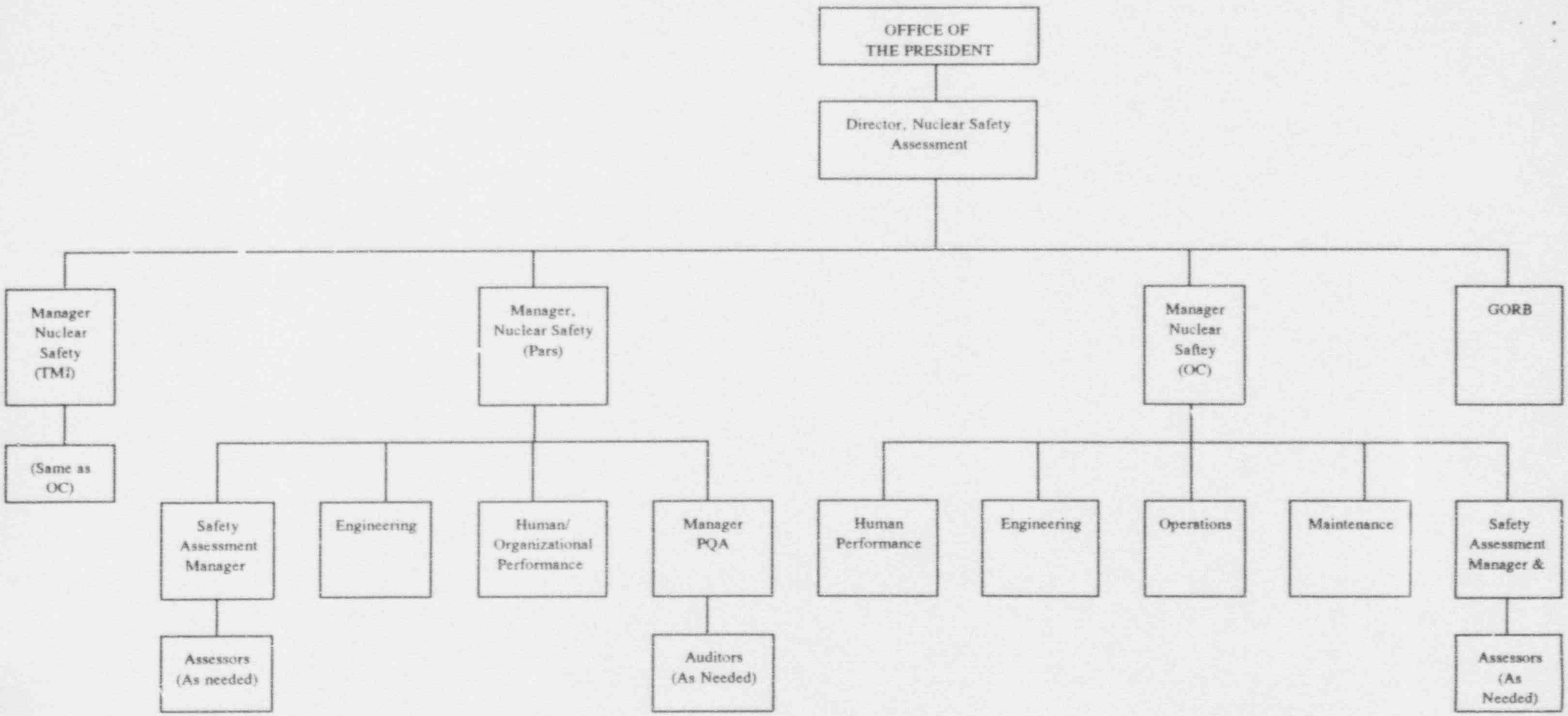
Note 3 - All groups, except for NDE/ISI, participate in development of the QA Annual Assessment. There would be a single assessment rather than the current separate QA and ISR assessments.

Note 4 - Currently QC has the lead on design package reviews and gets PQA input on procurement requirements when needed.

Note 5 - New assessment organization will need to have representation at daily coordination meetings, particularly during outages.

Note 6 - Monitor Certification is not required by regulation. Recommend having all Assessors certified as Auditors or be handled as Engineers (not certified).

Note 7 - For planning purposes this is shown as going to Plant Maintenance. This was agreed to contingent upon an anticipated decision to integrate Site Services and Plant Maintenance. The other alternative is Assessment.



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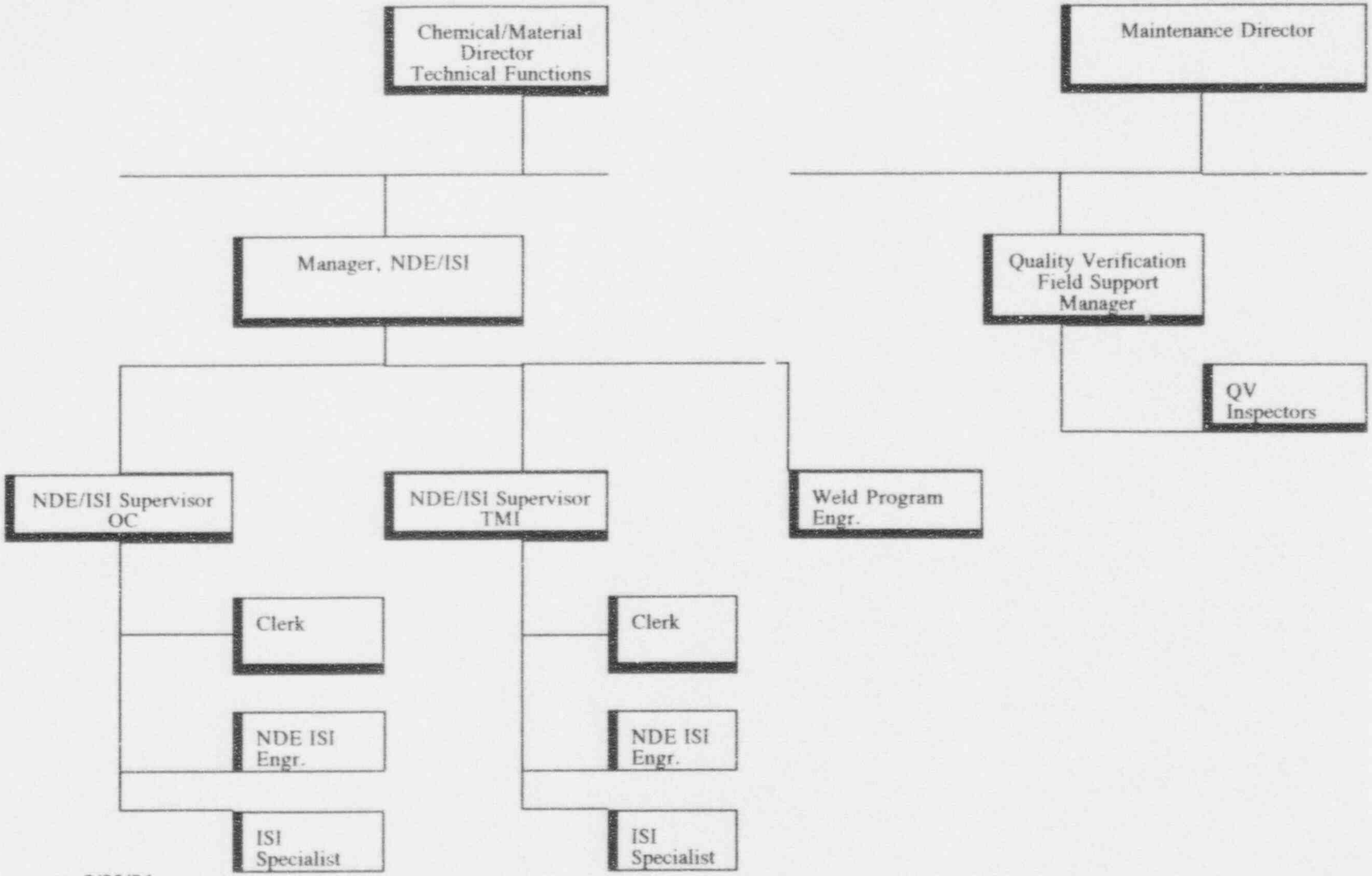

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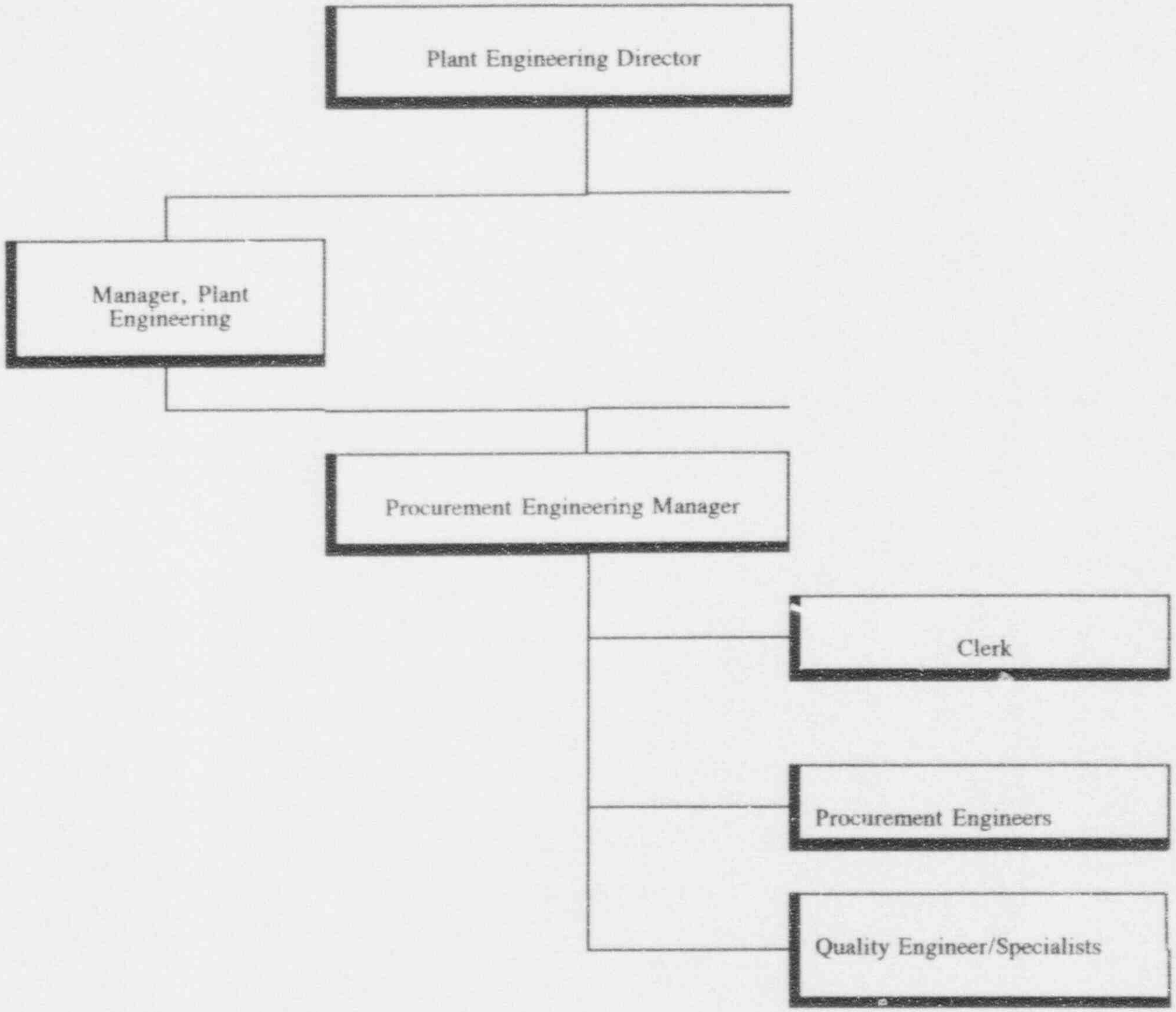

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KEY IMPLEMENTATION DATES

January 11, 1994	Approval to proceed with reorganization.
January 1994	Brief NRC on reorganization and obtain initial reaction to 50.54 (a) (3).
February 1994	Finalize QA Plan changes, and if required, submit to NRC for approval.
	Begin small group meetings for new organizational elements.
	Develop plan for final staffing levels and personnel assignments.
	Begin procedure changes required, including the Organization Plan.
March 1994	Continue small group meetings.
	Finalize assessment parameters to assure successful transition to the new organization.
	Develop post implementation assessment plans.
April 1994	If required, receive NRC approval.
	Make organizational changes.
September 1994	Assess implementation to assure full implementation, compliance with QA plan, and any performance issues.
March 1995	Conduct another assessment.
December 1995	Attain desired staffing levels.
	Conduct final special assessment.