U. S. NUCLEAR REGULATORY COMMISSION
REGION I

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License No.	NPF-57
Licensee:	Public Service Electric and Gas Company P.O. Box 236 Hancocks Bridge, New Jersey 08038
Facilities:	Hope Creek Nuclear Generating Station
Dates:	September 24, 1995 - November 8, 1995
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12/13/95
Date

Inspection Summary:

This inspection report documents inspections to assure public health and safety during day and back shift hours of station activities, including: operations, radiological controls, maintenance and surveillance testing, emergency preparedness, security, engineering/technical support, and safety assessment/quality verification. The following Executive Summary delineates the inspection findings and conclusions.

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EXECUTIVE SUMMARY

Hope Creek Inspection Report 50-354/95-17

September 24, 1995 - November 8, 1995

OPERATIONS

Plant operators demonstrated mixed results during their response to the numerous plant events that occurred during this report period. For example, responses to two events involving a feedwater pump oscillation and gross leakage from circulating water piping were considered prompt and effective. However, several operator performance problems were noted that contributed to or exacerbated other events; specifically a reactivity manipulation error, two safety tagging errors, and a failure to appropriately implement a technical specification action requirement. Overall organizational response to the large number of recent events was considered good in that the pertinent issues were effectively communicated to all station staff and management expectations were thoroughly reinforced. Corrective actions for the noted events were deemed to be both timely and appropriate. As a result of the quality of PSE&G's event follow up, the procedure violations associated with safety tagging and work control errors as well as the technical specification non-compliance regarding a failure to issue a timely report of an inoperable radiation monitor were considered non-cited violations.

MAINTENANCE/SURVEILLANCE

Routine plant maintenance and surveillance activities were generally conducted in accordance with approved plant procedures and were effective in minimizing the time that the associated systems were out of service. Timely and effective resolution of two unexpected events, one involving the inoperability of the high pressure coolant injection system due to an out of adjustment stop valve limit switch and the other involving inservice testing of standby liquid control pump discharge check valves, was considered excellent. However, several coordination and control problems were noted during a forced outage of a standby liquid control subsystem which caused the outage to be extensively delayed. A licensee identified technical specification non-compliance associated with a failure to test standby liquid control pump discharge check valves was considered a non-cited violation.

Maintenance planning and scheduling demonstrated mixed performance. While planning personnel generally conducted adequate assessments of the overall safety impact of performing system outages on-line and solicited formal feedback for future outage improvement, weaknesses were noted in the scheduling of these activities in that several were planned coincident with work or degraded conditions on redundant safety systems.

ENGINEERING

Station engineering activities generally supported reliable plant operation throughout the report period. System engineers continued to provide plant operators with useful summaries of degraded plant conditions and the means by which the effects of these conditions could be successfully mitigated. Engineering monitoring and assessment of conditions associated with a degraded reactor recirculation pump seal was considered to be excellent. Engineering leadership during the troubleshooting of degraded reactor feed pump controls was good, but the root cause of this operationally challenging condition was never definitively established.

The emergency diesel generators are meeting their established reliability goals. The diesel generator start times do not show engine degradation over the past several years. The starting times have remained relatively constant. The start timing failures were due to the application of inappropriate acceptance criteria in a revision of the monthly surveillance test procedure. The inappropriate criteria were implemented due to a lack of controls on the procedure revision process that allowed changing surveillance test criteria without input from the system engineers. Also, no review was conducted to ensure that the previous test results met the revised criteria. Other engine failures were appropriately evaluated and corrective actions have been effective in preventing recurrence.

PLANT SUPPORT

Radiation protection department planning and execution of a filter demineralizer septa changeout was very good, especially in light of the infrequent nature of the activity and its potential for high dose consequence. Observation of routine radiation protection activities also concluded that the program was effectively implemented.

Despite their inability to obtain a timely grab sample from the normal location (due to a valve failure) following the inoperability of the installed offgas system radiation monitor, chemistry technicians exhibited good innovation and coordination with other station departments to obtain a valid offgas sample from an alternate location. Security personnel responded well to a forced landing of a military helicopter on owner controlled property.

An announced inspection of the solid radwaste/transportation program was conducted by Mr. J. Noggle at the Hope Creek Nuclear Generating Station on October 23 - 27, 1995. Areas reviewed included management oversight, training, radwaste processing, radwaste sampling, radioactive material shipping, and onsite radwaste storage. The solid radwaste/transportation program was determined to be strong. Enhancements in waste characterization of contaminated materials were suggested. A reduction in the independent surveillance of radioactive shipments was noted. The licensee reinstated the review of all reportable quantity shipments. No violations of regulatory requirements were identified.

SAFETY ASSESSMENT/QUALITY VERIFICATION

Three quality assurance audits were completed during this report period which effectively examined the station's fire protection and radiological effluents programs, as well as the use and maintenance of plant's technical specifications. In all cases the audits were of adequate scope and duration and were staffed (in part) by experts from outside the licensee's organization to gain additional independence. An inspector assessment of the offsite safety review staff concluded that, while this organization complied with plant technical specification requirements, it had little opportunity to provide significant new assessment of station activities since it relied almost solely on "paper" reviews.

An inspector review of several recently issued licensee event reports determined that two of the events described violations of NRC requirements. However, in both cases, the issues were self-identified and did not result in a safety significant event. As a result of good management follow up, both issues were considered to be non-cited violations.

TABLE OF CONTENTS

DETAILS

1.0 SUMMARY OF OPERATIONS

The Hope Creek unit began the inspection period at 100% power and on September 28, 1995 began a planned coastdown at the end of the operating cycle 6. Normal power operations were maintained for the duration of the inspection period, although due to the coastdown power was reduced to 88%. At the end of the inspection period the unit had been maintained on-line continuously for 107 days.

During routine observation of control room activities the inspectors noted improved operational ownership of plant emerging conditions. On a number of occasions, operations' senior supervisors were noted to stop planned activities in order to respond to emerging plant conditions. As a result of the increased number of emerging equipment problems, especially relative to the emergency diesel generators, reactor manual controls and feedwater pump controls and steam supply, management elected to defer a number of maintenance activities that had been scheduled for completion on-line to the refueling outage.

During the inspection period licensee management issued new expectations to the operating staff regarding improved communications with the NRC inspectors. The inspectors noted that the operators immediately improved the level of communication with the NRC.

2.0 OPERATIONS

2.1 Inspection Findings and Significant Plant Events

The inspectors verified that Public Service Electric and Gas (PSE&G) operated the facilities safely and in conformance with regulatory requirements. The inspectors evaluated PSE&G's management control by direct observation of activities, tours of the facilities, interviews and discussions with personnel, independent verification of safety system status and technical specification compliance, and review of facility records. The inspectors performed normal and back-shift inspections, including 11 hours of deep back-shift inspections.

A number of operating events occurred during this period, the most significant of which included a 22,000 gallon spill of non-radioactive water into the turbine building resulting from personnel errors, a momentary loss of a service water subsystem resulting from personnel errors during a tagging evolution, and a reactivity manipulation error resulting from equipment failure coupled with personnel error. In addition to presenting a challenge to the control room operators, all of these events involved both personnel error and a lack of adequate supervisory oversight for the activity, and some also involved equipment malfunctions or procedure inadequacies previously known to the station. As a result of these events, a work stand-down was conducted by station management on October 24, 1995 to discuss various aspects of the events with all station personnel and to restate managements' expectations for response to plant events. The NRC is concerned with the number of challenges presented to the control room staff, especially involving events that could be avoided with sufficient attention to detail and supervisory oversight. However, the inspectors attended the work stand-down meetings and assessed that station management was similarly concerned and was implementing appropriate actions tc better prevent these types of events. Some of the actions included significant changes to the operating department management, control room staffing, improved pre-job briefings, and improved management oversight of the control room. Additional actions are planned to improve the work control process, including safety tagging; however, these actions will be implemented as part of the Hope Creek IMPACT Plan.

A description of the events follows:

1. On October 11, 1995 while two technicians were completing a calibration check on level switches associated with the demineralizer feed tanks, a non-safety related, balance-of-plant system, a non-radioactive water spill occurred. The test was a routine preventative maintenance activity for the control circuitry associated with the tank. However, conduct of the test resulted in the tank fill valve actually opening, since the activity was done with the controls on-line. While the valve was open, approximately 35,000 gallons of make-up water flowed to the demineralizer feed tanks, about 22,000 gallons of which overflowed from the tanks to the turbine building 54 foot elevation floor drain system. No safety related equipment became inoperable as a result, and operations and radiation protection personnel adequately responded to the event. It was determined by the licensee that: during the test, while the tank fill valve was open, instrumentation used by the technicians failed, resulting in their leaving the job site to retrieve a second instrument; that since the work order did not require any supporting safety tagging, neither the maintenance supervisor nor the work control supervisor performed a thorough review of the activity prior to authorizing start of work (had a thorough review been performed, the flow path that was opened leading to the spill would have been identified); that the job supervisor failed to conduct an adequate pre-job briefing; that while the technicians noted that the fill valve was responding to their testing, they did not recognize that with the valve open, water was being fed to the tanks located in a different room in the turbine building from where they were performing the test; and finally, the licensee also concluded that an Action Request (AR) (the licensee's process for identifying degraded or nonconforming conditions) had not been generated in a timely manner. Also, the NRC inspector was concerned that this event had occurred without any notice to the site inspectors until the day after the event. After discussion with station management relative to "informational" notification of the NRC resident inspectors, the licensee management clarified its expectations to the operators to ensure that more timely notification of such plant events were made.

2. On October 20, 1995, during a routine surveillance test of the control rod drives, three control rods were mispositioned by the control room operator. At the time of the event, Hope Creek was operating at about 90% power, in an end of cycle coastdown with all control rods fully withdrawn. The licensee reviewed this event and determined the

following facts. The attending reactor operator attempted to select and insert peripheral control rod number 02-19 from position 48 to position 46. However, at the time, the control room operators were unaware that the reactor manual control system (RMCS) had locked up, which resulted in a failure of the position indication display on both the Four Rod Display as well as the Full Core Display. While failed in this manner, neither system updated displayed information; however, actual controls associated with the reactor manual control system were not affected. After attempting to move the selected rod, the rod position still indicated step 48. Also, the control rod movement indicators on the reactor manual control station did not indicate any change in rod drive movement. This led the operators to conclude that the selected rod had not moved. The operator attempted to insert this rod again, with similar results. The operator then selected another peripheral rod and attempted to insert it to position 46. Again, no indication of rod movement was detected. The reactor operator then notified the on-duty SRO of the problem and again, attempted to insert control rod number 02-19 for the third time. The second control room operator noticed that the Full Core Display rod select indicator did not match the Reactor Manual Control console. While the console indicated rod 02-19 as selected, the Full Core Display indicated rod 42-03 as selected. The duty SRO then directed the reactor operator to select rod 42-03 and attempt to insert that rod. Again, no indication of rod movement was observed. The SRO then reviewed the plant process computer and found indication that all three rods had inserted, apparently for each time that the reactor operator had attempted a manual insert demand. The abnormal operating procedure was entered for rod control malfunction, the rods were returned to position 48 and repairs were made to two card connectors in reactor manual control system panel 10-C-650. After restoring the RMCS to a normal condition, two hydraulic control unit (HCU) accumulators were found in alarm. The Full Core Display also provides alarm indication for the HCUs and with it locked up, this alarm feature was lost. This required entry into technical specification limiting condition for operation 3.1.3.5, Control Rod Scram Accumulators. This requires restoration of the associated accumulators within one hour or be in hot shutdown within the following twelve hours. The accumulators were restored to normal and no additional actions by the operators were required at that time.

Because the control rod scram accumulator trouble alarm feature was masked by the RMCS lock up, additional actions were taken to periodically test the RMCS hourly by selecting a peripheral rod to ensure that the associated displays were updating properly. This was also done because this failure mechanism had no associated alarm feature and therefore, could occur without the operators knowing about it, as had occurred on October 20, 1995. During such a test on October 26, 1995, the RMCS was determined to again be locked up. This resulted in additional repairs to the associated controller cards and while the system was failed, operators declared all HCU accumulators inoperable and entered the 12 hour shutdown action statement. Repairs were completed by cleaning the contacts on the associated "clock" card and the technical specification action statement exited. Additional corrective actions are planned to be completed during the refueling outage to provide an alarm feature for the operators for such failures of the RMCS, as well as to assess the nature of the intermittent failure to prevent similar problems. Finally, a multi-disciplined root cause team was commenced to identify whether additional corrective actions are necessary to prevent recurrence.

3. On October 13, 1995, a tagging evolution for the "B" service water pump traveling screen was implemented in which the "D" traveling screen breaker was erroneously included. The error was discovered immediately upon opening the wrong breaker and operators quickly restored appropriate system configuration without any adverse impact on the plant. Again, on October 22, 1995, a tagging evolution implemented on the "C" feedwater heater string included a component in the "B" feedwater heater string. On this occasion, however, the wrong component was identified by the operator prior to implementation. In both of these tagging errors, the tagout had been reviewed and approved by the work control group.

   Operations review of these and other recent tagging errors concluded that no procedural deficiencies exist; however, a lack of attention to detail was indicated. Operations management provided guidance regarding accountability to the operators for personnel related tagging errors, and have improved the pre-job briefing process which is now also done for tagging evolutions. Additional action is planned to improve the overall work control process, which includes safety tagging; however, this action will be implemented as part of the Hope Creek IMPACT Plan.

   Several other plant events occurred this period that led to operator/technician actions to recover required equipment within a short period of time or would have resulted in having to shut the plant down. These issues, primarily the result of equipment failure or procedural inadequacy, included a runback of one of the operating feedwater pumps, repeated failures of emergency diesel generators during testing, an inoperable sample station for the offgas system, and a circulating water leak in the condenser area.

NRC Assessment:

Regarding the 22,000 gallon spill in the turbine building, the inspectors observed interviews conducted by the independent root cause team and walked down the affected system(s) and controls. Based on this review, the inspectors concurred with the team's overall assessment that Hope Creek personnel missed several opportunities to preclude this event from occurring. Specifically: (1) the work order prepared by planning personnel did not provide sufficient information for work control staff and maintenance supervision, (2) work control staff and maintenance supervision did not sufficiently review the planned work to fully understand its impact (and evaluate whether equipment tagging was required), (3) the pre-job brief, though conducted, was inadequate because no checklist or references were used. In addition, the technicians involved did not stop and question the consequences of the unexpected opening of the tank make-up valve during the actual device calibration. The inspectors also learned that this specific work activity was conducted on several previous occasions and that it was only fortuitous no tank overflows resulted. A post-event root cause analysis team review initiated by plant management identified appropriate root causes, as well as earlier events that if corrected, should have prevented this event. The inspectors assessed the licensee's root cause analysis as very comprehensive and providing critical self evaluation. The inspectors also concluded that several human error and programmatic deficiencies permitted the event to occur. As a result of this event station management provided improved guidance to the operators.

Following issuance of new station management expectations/guidance regarding operations communications with the NRC site inspectors after the October 11, 1995 spill into the turbine building, the NRC inspectors noted that communications did in fact improve.

The inspectors assessed that the corrective actions taken and planned for the above personnel errors were comprehensive. Generally, while noting that each of these events or equipment failures resulted in challenges to the operating crew, overall performance was considered mixed. In many cases operators responded well to the conditions, such as the runback of the "B" reactor feedpump and leakage in the condenser bay. While the operator response to the second failure of the RMCS was good, the initial failure went unrecognized even though the plant process computer was available for operator review which would have indicated the problem. This led to the operator continuing to insert control rods without knowing it. Similarly, both tagging procedure errors, as well as the 22,000 gallon spill, involved an inadequate review by work control personnel that led to the events. On one of these occasions the operator failed to recognize the error prior to tagging the wrong component, and, on the second occasion, the error was identified prior to implementation. While some additional activities are planned to prevent recurrence of the errors, effective interim measures have been taken.

The inspectors also noted during this period that operations department ownership of plant conditions was mixed. As an example of good operations ownership/leadership, operations prevented scheduling of plant activities that could have resulted in a feedwater transient at a time when the normal feedwater was degraded and HPCI was inoperable. However, this type of control was less evident, when scheduled activities on the "A" PCIG system and the "D" EDG were authorized, which potentially affected both trains of MSIV sealing system; and also, when work was authorized that led to the 22,000 gallon spill in the turbine building without a full review of the activity. As a result of these events, operations improved the pre-job briefing process, and provided additional expertise to the control room, including additional management oversight in an effort to improve operations leadership. In response to an operations department concern about the high number of planned activities prior to the scheduled refueling outage, management changed the schedule to move a large number of these activities to the outage and possibly remove some of the plant conditions that would complicate operator actions in response to emerging plant problems.

Overall organizational response to the noted events was considered acceptable; the topics addressed during the Hope Creek stand down and subsequent corrective actions were considered good. In addition, the organization changes to provide additional management oversight of operations and to move a number of planned activities to the refueling outage was considered good. The number of events and minor equipment problems was clearly challenging the operating crews ability to remain focused on safe plant operation and the efforts to remove some of these challenges were noteworthy. The procedure violations described above associated with inadequate work control and safety tagging were both licensee identified and corrected, and were not the result of a willful act. Therefore, these procedure violations are being treated as a Non-Cited Violation, consistent with Section VII of the NRC Enforcement Policy.

2.2 Radioactive Effluent Pathway Monitoring

During this report period, Hope Creek operators continued to experience reliability problems with effluent release path radiation monitoring equipment. Specifically, the offgas pretreatment radiation monitors and the filtration, recirculation, and ventilation system radiation monitors were inoperable for a large fraction of the period. While these particular instruments were unavailable, technical specifications required that periodic "grab" samples be taken as a compensatory measure. The inspectors concluded that the chronic unavailability of the noted radiation monitors was a significant distraction to plant operators.

A separate but related issue also emerged this period following the inoperability of the filtration, recirculation, and ventilation system radiation monitor. Technical specification 3.3.7.5 ("Accident Monitoring") states in part that, if the instrument is not restored to an operable status within 72 hours, a special report must be submitted to the NRC within 14 days. However, the operations shift, following the removal of this monitor on September 13, 1995, failed to thoroughly review and implement the requirements of this technical specification action statement, since they were not tracking the special report as a 14 day requirement. This failure was self identified and corrective actions were effected to ensure that operators would refer to the appropriate action statement for future such equipment failures. The individual involved was disciplined for not referring to the technical specifications and the operating crews were provided guidance about appropriate technical specification review for identified deficiencies. As a result of this event, additional problems were noted with the procedure used by the control room operators to identify technical specification actions. These problems were also adequately addressed by the licensee corrective actions. Since this violation was self identified and the corrective actions were both prompt and comprehensive, and was not the result of a willful act, it is being treated as a Non-Cited Violation, consistent with Section VII of the NRC Enforcement Policy.

3.0 MAINTENANCE/SURVEILLANCE TESTING

3.1 Maintenance Inspection Activity

The inspectors observed selected surveillance and maintenance activities on safety-related and important-to-safety equipment to determine if PSE&G conducted these activities in accordance with approved procedures, technical specifications, and appropriate industrial codes and standards. Routine observation of daily planning meetings and discussions relative to net positive safety gain for on-line maintenance activities were generally assessed as positive indicators. In general, the activities observed were judged effective in meeting the safety objectives of the Hope Creek maintenance and surveillance program, except where specifically noted otherwise.

3.2 Inspection Findings

Maintenance/Surveillance Observations and Performance Assessment

The inspectors witnessed portions of several maintenance and surveillance activities this report period, including close observation of the D service water traveling screen repairs, the A reactor protection system electrical protection assembly scheduled outage, the A primary containment instrument gas outage, and the residual heat removal system (B loop) work to install a subsystem cross-tie design change. The inspectors concluded that all of the observed work was performed in accordance with established procedures and minimized the amount of time the associated systems were unavailable. However, on a few occasions, control room operators were not aware of all the safety related maintenance activities ongoing in the plant. The inspectors attributed this deficiency to less than fully effective shift turnovers and weak communications between work control staff and plant operators.

In general, station planning personnel adequately evaluated the overall safety impact of scheduled system outages, and conducted formal post-outage assessments to improve planning for future work. However, the inspectors noted some weaknesses associated with maintenance scheduling. Specifically, the safety impact of voluntarily removing equipment from service while redundant or degraded support equipment work was in progress was not always adequately evaluated or considered. Examples included: (1) scheduling a 24 hour loaded C emergency diesel generator run in conjunction with a forced outage of the B reactor feed pump which had the potential to trip the A reactor feed pump during a vital bus transfer; (2)scheduling a B reactor protection system motor generator outage for a period when controls technicians were scheduled to perform testing on A and C channel trip logic; and, (3) scheduling an A primary containment instrument gas outage concurrently with ongoing maintenance on a diesel generator that supplies emergency power to the redundant instrument gas system.

As a result of these and other concerns raised by the operations staff, plant management elected to defer a significant amount of planned work until the refueling outage. In addition, lessons learned from these concerns were to be incorporated in the improvements to the work control process as part of the

Hope Creek Impact Plan. The inspectors assessed that management response to these concerns was appropriate, and further, that identification of the concerns by operations were good.

High Pressure Coolant Injection System Inoperable Following Weekly Oil Sample

On October 24, 1995, the inspectors witnessed an outstanding overall response by operations, maintenance, and system engineering personnel in the resolution of an event which resulted in the high pressure coolant injection system being declared inoperable. Upon completion of a weekly oil sample, the turbine auxiliary oil pump was secured in order to return the high pressure injection system to standby status. This action should have caused the turbine trip throttle valve (stop valve) and control valves to close. However, control room operators alertly noted that the stop valve did not indicate closed after the oil pump was stopped. Pending troubleshooting, operators declared the system inoperable and made the appropriate 10 CFR part 50.72 four hour non-emergency report to the NRC. Subsequent evaluation by maintenance technicians and the system engineer determined that the stop valve was in fact shut but the position indication limit switch was out of adjustment. The switch was promptly adjusted and the system returned to an operable status within two hours.

Standby Liquid Control System Forced Outage

On November 1, 1995, plant operators declared the "B" subsystem of standby liquid control inoperable when the associated pump failed to deliver at least the minimum required flow (41.2 gpm) during an in service test. In addition, on November 2, 1995, the Hope Creek quality assurance department determined that both of the standby liquid control pump discharge check valves had never been tested in accordance with technical specification 4.0.5 (ASME Section XI In service Testing). As a result, both subsystems were declared inoperable requiring an immediate plant shutdown; however, plant operators invoked the 24 hour delay period granted by technical specification 4.0.3 in order to conduct the appropriate valve testing. The inspectors noted that the actions taken to resolve this second concern were prompt and effective, and was a good example of a well coordinated plant maintenance activity (appropriate valve testing was completed within 6 hours). However, resolution of the first concern, which provided a 7 day allowed outage time per technical specification 3.1.5, was in direct contrast to this assessment.

The inspectors witnessed several troubleshooting and repair coordination problems during the standby liquid control system forced outage. For example, engineering personnel suspected that leakage past the "B" pump discharge relief valve was the cause of the pump low flow condition, but the valve was not disassembled and inspected prior to its reinstallation in the system. This resulted in an outage delay to remove the valve again and examine its internals. Further delays were experienced because of other planning and coordination problems, including: (1) maintenance personnel waited for direction to open and inspect the pump (to ensure that previously identified metal shavings in the system's test tank had not caused damage), (2) the pump plunger stuffing box packing overheated despite two attempts to resolve the concern, and (3) the operations surveillance procedure had to be modified by an on-the-spot change to ensure that the test could be completed successfully. Operators cleared the action statement and declared the system operable only 20 minutes before it was due to expire. The root cause(s) of these problems had not been definitively established prior to the end of the report period.

With regard to the above noted quality assurance finding that identified standby liquid control pump discharge valves which had never been tested in accordance with the inservice test program, the inspectors concluded that once identified, Hope Creek took prompt and effective action to resolve the concern. This violation of technical specification requirements is considered a licensee identified violation and is treated as a non-cited violation, consistent with Section VII of the NRC Enforcement Policy.

4.0 ENGINEERING

4.1 Inspection Findings

Reactor Recirculation Pump Seal Degradation

During this report period, the inspectors noted excellent system engineering monitoring, assessment, and communication of degraded conditions associated with the "B" reactor recirculation pump seal package. Over the course of the last 1 ½ months, second stage seal cavity pressure gradually increased to nearly 700 psig at the end of the period (nominally 500 psig), indicating a continued degradation of the first stage seal. The system engineer consulted with outside industry experts and the seal vendor to understand all of the potential seal failure mechanisms. Further, an assessment was made to understand the worst case scenario (complete seal failure), evaluate second stage seal performance, predict first stage seal response to recirculation pump speed changes and plant transients, and provide recommended operational guidance to plant operators to minimize the potential for further degradation. This information was documented in a memorandum to the shift and included a list of specific parameters to monitor, including drywell floor and equipment drain leakage rates (the inspector verified that leak rates did not change significantly since seal degradation was first identified). Independent inspector follow up noted that operators were familiar with this issue and were monitoring all of the noted parameters appropriately.

"B" Reactor Feed Pump Oscillations

On October 24, 1995, plant operators experienced oscillations in "B" reactor feed pump speed with the pump in both automatic and manual control, resulting in the pump's removal from service. While impact on the plant was minimal during the event, the resultant feed pump configuration impacted the plant's overall ability to cope with any future reactor level transient since one of the two remaining feed pump turbines did not have high pressure steam available due to a previously identified inlet steam isolation valve leak problem.

The inspectors noted that engineering follow up analysis and related troubleshooting on the reactor feed pump controls were generally comprehensive, except that the cause(s) of the observed oscillations were never fully identified. Instead, the three "most likely" causes were isolated, two of which were corrected by replacement of a suspect "loss of control oil pressure" trip relay. The most likely cause (a postulated Bailey solid state logic module fault), was not definitively established. Though symptoms of this event coincided with previously collected data stemming from earlier events, bench testing of the Bailey logic card did not identify any problems. System engineering personnel effectively collaborated to develop a detailed list of all possible failure mechanisms, and systematically attempted to rule out each possibility. Based on engineering recommendation, operators returned the pump to normal service with an event recorder attached to the output of the noted logic modules. System engineers also provided the plant operators with a detailed memorandum discussing this issue and recommended guidance for how to handle any future pump oscillations.

5.0 PLANT SUPPORT

5.1 Radiological Controls and Chemistry

The inspector periodically verified PSE&G's conformance with their radiological protection program. During plant tours and direct observation of operations and maintenance activities, the inspector observed that the radiological protection program was being properly implemented.

Spent Fuel Pool Filter/Demineralizer Changeout

The inspectors observed the removal of the spent fuel pool filter/demineralizer septum from its tank to a temporary storage cell within the radiological control area and subsequent transfer to the Temporary Radwaste Storage Facility. The radiation protection coverage of this potentially high dose job was very good. Appropriate controls were established for the technicians performing the removal of the septum from the tank to the temporary cask. Good coordination between engineering, maintenance and radiation protection departments and overall good planning was noted, as the job was performed without unusual delay or difficulties, especially in light of the infrequent nature of the activity. Appropriate radiological posting of conditions and monitoring of personnel dose rates were observed throughout the activity. Excellent control of the materials, once removed from the tank, were also observed until disposal at the Temporary Radwaste Storage Facility.

Alternate Sampling of the Main Condenser Offgas Train

On October 26, 1995, chemistry technicians were unable to obtain a technical specification 3.3.7.1 required "grab" sample necessitated by an earlier failure of the installed offgas pretreatment radiation monitor. The inability to obtain the grab sample was caused in part by a failed closed sample panel inlet isolation valve. Repairs to this valve were not possible without an offgas train shutdown, which could only occur with the plant shutdown.

The inspectors noted good coordination between chemistry, radwaste, and operations staff in their effort to obtain a valid grab sample from an alternate location. Failure to obtain the grab sample within the technical specification prescribed 8 hour interval from the normal location resulted in an operator entry into a 12 hour plant shutdown action statement. Approximately 6 hours into this 12 hour period, technicians, under direct supervision by department management, successfully obtained an offgas sample from the offgas hydrogen/oxygen analyzer sample piping using procedural guidance dictated in a work order. Operators exited the 12 hour shutdown action and continued plant operation by drawing the required periodic offgas grab samples from this alternate location.

The inspectors observed the conduct of an offgas sample from the alternate location (as well as post-sample counting and analysis) and concluded that these activities were performed efficiently and in accordance with technical specifications and a newly approved sampling procedure. Further, an independent review of chemistry department logs subsequent to the original missed sample indicated that all grab samples were obtained at a frequency more conservative than technical specification requirements. The inspector noted that, based on the inability to repair the original valve failure, this new sampling methodology would be employed until repair work could be completed during the next plant shutdown.

5.2 Emergency Preparedness

The inspector reviewed PSE&G's conformance with 10 CFR 50.47 regarding implementation of the emergency plan and procedures. In addition, the inspector reviewed licensee event notifications and reporting requirements per 10 CFR 50.72 and 73. During this inspection period there were no required emergency notifications.

5.3 Security

The NRC verified PSE&G's conformance with the security program, including the adequacy of staffing, entry control, alarm stations, and physical boundaries. The inspectors observed good performance by Security Department personnel in their conduct of routine activities. During tours of the protected and vital areas, the inspectors observed that the security related hardware was maintained in good working order. The inspectors observed the implementation of actions taken relative to preventing unauthorized vehicle entry to the site. These activities appeared to be well controlled. On October 9, 1995, a Chinook helicopter made a forced landing northwest of the Hope Creek cooling tower, on owner controlled land but outside of the protected area. The licensee security force responded by staging response personnel in accordance with their security plan; provided both visual and camera coverage of the helicopter and its crew while repairs were effected to the helicopter controls; and, dispatched a supervisor to the helicopter to ascertain the reason for the landing. The control room operators declared an unusual event due to unplanned air traffic over the station property. Subsequently, after repairs were effected, the helicopter, owned by the Royal Netherlands Airforce and being retrofitted by the Boeing Corporation, left the owner control area and normal plant response readiness was reestablished.

5.4 Housekeeping

The inspector reviewed PSE&G's housekeeping conditions and cleanliness controls in accordance with nuclear department administrative procedures. During routine plant tours and in system restoration after maintenance activities, the inspector observed generally good implementation of the station cleanliness program.

5.5 Fire Protection

The inspector reviewed PSE&G's fire protection program implementation in accordance with nuclear department administrative procedures. Items included fire watches, ignition sources, fire brigade manning, fire detection and suppression systems, and fire barriers and doors. The inspectors noted that the licensee identified and corrected minor deficiencies relative to combustible material storage containers within the plant.

6.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION

Quality Assurance Audit of Site Fire Protection

On September 25, 1995, the quality assurance department completed an audit of the site fire protection program. The inspectors concluded that the audit, conducted as a team review with assistance from specialists outside PSE&G, was of excellent scope and resulted in findings that were based on both programmatic review and observations of in-process activities. The results of the audit were discussed with the inspectors and led to the generation of sixteen action requests for resolution. The inspectors determined that the results of this audit indicated further evidence of improved quality assurance department scrutiny of plant activities, since many of the deficiencies identified during this audit had existed for several years (i.e. during previous audits).

Quality Assurance Audit of Site Radiological Effluents

On October 2, 1995, the quality assurance department completed an audit of the radiological effluents programs at both Salem and Hope Creek. The audit team included three specialists from outside PSE&G and the scope and findings were described to the NRC inspectors. While a number of minor negative findings were identified resulting in a number of action requests, the overall conclusion of the audit was that the radiological effluent and meteorological monitoring programs were being effectively implemented.

Quality Assurance Audit of Technical Specifications

On October 9, 1995, the quality assurance department completed an audit of the Technical Specification use and maintenance for both the Salem and Hope Creek stations. The audit team included a number of experts from outside PSE&G. Overall the audit concluded that the technical specifications are being implemented at both stations; however, a number of minor concerns were identified that in the aggregate indicate the need for additional management attention and reinforced the prior management decision to implement a technical specification improvement program.

Offsite Safety Review

The inspectors reviewed a sample of activities conducted by the Offsite Safety Review (OSR) Group during the inspection period. Based on that review and interviews with the Principal Engineer of the OSR, it was clear that the activities met the requirements of the technical specifications. In addition, the inspector reviewed a sampling of the OSR membership qualifications and found that appropriate expertise was maintained in the OSR as required by the technical specifications. While the activities demonstrated that the OSR is meeting the requirements, it was also readily apparent that the OSR primarily conducted paper reviews to form the basis of their assessments. The OSR does not normally conduct business as a committee; but rather, individual assignees provide assessment to the group. If the group needs additional information to complete a review, then a committee-like meeting can take place with the appropriate station responsible group for the activity under review. Overall, the inspector assessed that the OSR is meeting the plant technical specification requirements; however, due to the method of the review process, the group has little opportunity to provide significant new assessment of station activities. In spite of this, the group does provide independent assessment from very experienced experts that adds confidence to the station management processes.

7.0 LICENSEE EVENT REPORTS (LER), PERIODIC AND SPECIAL REPORTS, AND OPEN ITEM FOLLOWUP

7.1 LERs and Reports

The inspectors reviewed the following LERs to determine whether the licensee accurately described the event and to determine if licensee responses to the events were adequate.

LER 95-013 - During June, 1995, the licensee determined that piping for the Turbine First Stage Pressure Inputs to the reactor protection system instruments and the Low Vacuum Input to the nuclear steam supply shutoff system were not visually inspected during pressure tests in the second inspection period of the 10 year in-service inspection interval. This surveillance is considered to have been overdue since April 27, 1995. The root cause was identified as personnel error in that an inadequate review took place when converting items in the Long Term Plan into the computerized surveillance scheduling system. The corrective actions included: inspecting the affected lines; updating the surveillance scheduling system; and review of the in-service inspection Long Term Plan to ensure compliance with requirements. This missed surveillance requirement is considered to be a Non-Cited Violation, consistent with Section VII of the NRC Enforcement Policy.

LER 95-014 - On July 3, 1995, an automatic ESF actuation occurred when the HPCI pump suction path swapped-over from the CST to the Suppression Chamber on high Torus level. The swap-over occurred following surveillance testing of the HPCI Minimum Flow Valve logic channel calibration and subsequent performance of routine Drywell Nitrogen make-up activities. Both activities slightly raised Torus water level. The licensee stated the root cause was that shift personnel did not fully understand the potential effects of the 'total loop' instrument accuracy when determining the consequences of performing activities that would either increase the mass of water within the Torus or effect the level transmitters readings (see LER 95-020). Corrective actions involved: counseling operations personnel regarding instrument inaccuracies; issuing operations personnel a letter covering lessons learned; and, evaluating simulator training guides to emphasize differences between simulator requirements and actual plant instrumentation characteristics.

LER 95-015 - On June 30, the licensee entered a 7 day LCO due to an inoperable 'A' Control Room Ventilation train following a trip. On July 7, 1995 the LCO expired and the licensee reduced power in accordance with the TS action statement. Shutdown was completed on July 8, 1995. The licensee determined the root cause to be a momentary power interruption to the control circuit due to a problem with a Freon temperature switch and lengthy cable runs which resulted in large voltage drops sufficient to prevent the control circuit from recovering. The corrective actions included replacement of the temperature switch, several relays and installation of interposing relays to effectively reduce the cable length by 4000 feet. This event and the associated troubleshooting and corrective actions were described in NRC IRs 50-354/95-10 and 50-354/95-11.

LER 95-016 - On July 8, 1995, a Shutdown Cooling Bypass Event occurred which rendered the shutdown cooling mode of the RHR inoperable. The event was initiated when operators positioned the Reactor Recirculation Pump discharge valve partially open to mitigate potential thermal binding. During the shutdown cooling evolution, approximately 2000 gpm of RHR heat exchanger outlet flow was diverted through the open valve and re-directed to the RHR shutdown cooling suction line. Weeks after the event, the licensee determined that the plant's operational condition had changed from Cold Shutdown to Hot Shutdown. The licensee identified the root causes as procedural non-compliance, lack of questioning attitude, not believing indications, and lack of follow-up regarding verification and validation of plant indications. Contributing causes include inadequate training and inadequate Operational Events Follow-up review. The licensee identified twenty-two corrective actions related to this event. Some of these actions involved incorporating the event into initial Licensed Operator training; commissioning an independent, multi-disciplined root cause team; revision of the system operating procedures regarding manipulations of the recirculation system suction and discharge valves; re-evaluation the long term solution of the existing thermal binding; other actions further address personnel, training, and root cause determination activities.

The NRC conducted an independent inspection of this event (see NRC IR 50-354/95-81). As a result of this inspection a Pre-decisional Enforcement Conference was held with PSE&G on November 6, 1995. This matter is still pending final NRC review for appropriate enforcement.

LER 95-017 - On July 13, 1995, in response to the discovery of a drawing discrepancy, a licensee review revealed surveillance testing of the vital bus load shedding circuits was incomplete. As a result, the required technical specification surveillance testing was considered to have been missed and all four diesel generators were declared inoperable. The licensee attributed the cause to be that the surveillance procedures did not provide sufficient overlap to ensure Technical Specification testing requirements were met for the complete circuit. The corrective actions included; preparation and issuance of new test procedures, and testing of the previously untested segments of the circuits; and, development of a technical specification surveillance procedure adequacy review program to review selected surveillance tests to ensure they incorporate adequate overlap testing. This event was discussed in NRC IR 50-354/95-11 and was considered to be one example of a number of technical specification violations that were cited in a Notice of Violation issued with that report.

LER 95-018 - On July 20, 1995, the licensee discovered that a single channel calibration of the ADS actuation instrumentation performed on June 28, 1995, had been improperly credited as a functional test involving three channels. A licensee review of test procedures and work histories, dating back to 1991, revealed that on three different occasions, multi-channel testing of ECCS instrumentation was improperly credited based on a single channel calibration. The licensee attributes the missed surveillances to functional test procedures that improperly allowed crediting of multi-channel test based on performance of a single channel calibration. Corrective actions included: correcting procedures errors which allowed improper crediting of functional tests; successfully performing the functional tests improperly credited in 1995; adding precaution statements to the multi-channel functional test procedures; reviewing all I&C functional test procedures involving more than one channel; and sending all I&C personnel a memo identifying the functional tests that can not be credited by the completion of a single calibration. This event was also described in NRC IR 50-354/95-11 and was considered to be examples of technical specification violations that were cited in a Notice of Violation issued with that report.

LER 95-019 - On July 31, 1995, the RCIC Jockey pump was declared inoperable during the performance of the quarterly In-Service Test (IST). The operability declaration was due to pump cavitation from insufficient NPSH when the pump suction was aligned to the torus. The normal (and previously used suction for such testing) path from the CST made it difficult to monitor equipment performance in accordance with ASME codes since variations in CST level between periodic in service tests made it difficult to obtain reliable pump performance data for trending purposes. Therefore, the torus suction path was added to the RCIC IST procedure to minimize the effects of level variations between tests. The apparent cause of this event was poor initial design when sizing torus suction piping. Corrective actions included replacing the original one inch suction piping with two inch diameter piping and revising the affected design calculations to reflect the larger suction piping. After modification, the pump retested successfully with suction from the torus. Inspection of the removed one inch pipe revealed no blockage or interior build-up of corrosion products that could have resulted in the pump cavitation.

LER 95-020 - On September 8, 1995, an automatic ESF actuation occurred when the HPCI pump suction path swapped-over from the CST to the Suppression Chamber on high Torus level. Prior to the event, Torus water level and temperature were higher than normal values due, in part, to in-leakage from 3 weeping SRVs. To lower water temperature, the RHR system was placed in the Torus Cooling mode. Eleven hours later, operators began routine Drywell Nitrogen make-up activities which was expected to raise Torus level slightly. One hour after nitrogen addition, a high Torus water level alarm was received while control room indicators were reading below the trip set point of 78.5 inches. The licensee attributed the apparent cause of the event to inadequate and ineffective corrective actions in preventing a recurring event (see LER 95-014). Interim actions included administratively limiting Torus level to 77 inches as displayed on the narrow range indicator; performing calibration checks on all Torus level transmitters; and other related actions. The licensee will provide a supplemental LER by November 30 describing the root cause. The apparent violation for ineffective corrective actions is considered a licensee identified violation and is treated as a Non-Cited Violation, consistent with Section VII of the NRC Enforcement Policy.

LER 95-021 - On September 20, 1995, the HPCI system was declared inoperable because the system oil reservoir sample indicated a moisture content of 0.23% which is above the specified limit of 0.20% established by the licensee's vendor. The apparent cause of this event was steam leakage through the turbine steam admission valve. A contributing factor was that two previously planned corrective actions, that were scheduled to be completed in the upcoming refueling outage, had not yet been effected. The licensee's immediate action was to replace the HPCI lube oil. Planned corrective actions include: repair of the steam admission valve during RFO-6 in November 1995; and, installation of a low point drain valve on the reservoir during RFO-6. Other activities prior to the refueling outage included: increased sampling frequency; periodic use of the barometric condenser to reduce moisture; and, periodic removal of the oil reservoir bottoms. This event was described in NRC IR 50-354/95-16.

The LERs listed above are considered closed.

8.0 EXIT INTERVIEWS/MEETINGS

8.1 Resident Exit Meeting

The inspectors met with Mr. M. Reddemann and other PSE&G personnel periodically and at the end of the inspection report period to summarize the scope and findings of their inspection activities.

Based on NRC Region I review and discussions with PSE&G, it was determined that this report does not contain information subject to 10 CFR 2 restrictions.

8.2 NRC Management Visits

On October 4, 1995, Mr. Thomas T. Martin, Regional Administrator NRC Region I toured the Hope Creek facility and met with station management.

8.3 Management Meetings

- A public outage risk management meeting to discuss the upcoming Hope Creek refueling outage was held on November 6, 1995 in the NRC Region I office. The focus of the meeting was to understand the scope of the outage and the licensee's plans for ensuring shutdown risks are minimized. The licensee presented information about the recent management initiatives that will broaden the scope of planned activities for the upcoming outage, and responded to NRC questions about how the additional work will be scheduled to manage overall shutdown risk. No presentation materials were provided to the NRC at that meeting.

- A closed predecisional enforcement conference regarding the findings of the July 8 and 9, 1995 shutdown cooling bypass event was held in the NRC Region I office on November 6, 1995. The licensee agreed with the independent NRC findings as described in NRC IR 50-354/95-81. In addition, the licensee's presentation focused on additional findings relative to the poor operator performance that have been identified since that event resulting from the corrective actions taken to date. The licensee's presentation materials are attached to this report.

8.4 Licensee Management Changes

During the inspection period the licensee announced the following management and organizational changes:

(1) On October 27, 1995, W. O'Malley left the position as Hope Creek operations manager. Initially, H. Hanson, Hope Creek operating engineer, acted as operations manager. Subsequently, on November 13, 1995, R. Gambone was made the temporary operations manager while the licensee pursues outside candidates to fill the position full time.

(2) On October 23, 1995, E. Harkness returned to Hope Creek from the Salem station where he served as planning/scheduling manager to become Hope Creek operating engineer.

(3) On October 25, 1995, the licensee announced an organizational restructuring that resulted in the consolidation of chemistry, radiation protection, and radwaste operations into a single department. K. Maza, former manager of the radiation protection department, became the manager of this new combined department. Both the chemistry and radwaste operations manager positions (which will report to K. Maza) remains vacant while the licensee pursues outside candidates to fill these positions full time.

ATTACHMENT 1

U. S. NUCLEAR REGULATORY COMMISSION
REGION I

REPORT/DOCKET NO. 50-354/95-~~16~~ 17

LICENSEE: Public Service Electric and Gas Company
Hancocks Bridge, New Jersey

FACILITY: Hope Creek Nuclear Generating Station

DATES: October 16 - 20, 1995

INSPECTOR: Roy L Fuhrmeister 2DEC95

Roy Fuhrmeister, Sr. Reactor Engineer
Electrical Engineering Branch
Division of Reactor Safety
Date

APPROVED: William H. Ruland 12/4/95

William H. Ruland, Chief
Electrical Engineering Branch
Division of Reactor Safety
Date

Areas Inspected: Emergency Diesel Generator testing, maintenance, and reliability.

REPORT DETAILS FOR HOPE CREEK DIESEL GENERATOR INSPECTION
50-354/95-17

1.0 OBJECTIVE (61726, 62703)

This inspection was conducted to assess the reliability of the emergency diesel generators (EDGs) at the Hope Creek Generating Station, in light of the apparent test failures experienced in late September 1995.

2.0 BACKGROUND

On July 9, 1995, during review of an apparently failed monthly surveillance test on a diesel generator at Salem, inappropriate acceptance criteria were identified by PSE&G as the cause of the apparent failure. On July 11, 1995, Salem Units 1 and 2 reported to NRC under 10 CFR 50.72(b)(2)(i) that all six diesel generators were inoperable due to test results not adequately documenting that all monthly surveillance test requirements had been met. This report was subsequently withdrawn on August 1, 1995, based on an update which indicated that the diesels were actually operable, as demonstrated by testing, and that the inadequate test data represented a missed surveillance.

This information was reviewed at an Operating Experience Feedback (OEF) program meeting at Hope Creek on July 20, 1995 (prior to the update and retraction). At this time, there was insufficient information available to determine the details and exact nature of the problem. At the OEF meeting, the General Manager assigned action to the Operations Department to review and revise procedures to ensure that a similar problem did not exist at Hope Creek. As a result, the monthly surveillance test criteria were revised to require that the EDG voltage and frequency stabilize within their normal range in 10 seconds, and the revised procedures were issued in September 1995. No review was conducted to ensure that the revised criteria had been previously met, and the specifics of the Salem report were not analyzed.

The first monthly test with the revised criteria was conducted September 22, 1995, on the "B" EDG. The unit failed its starting time test, and was declared inoperable. Several starts were conducted to tune the governor to meet the revised acceptance criteria. In addition, actions were taken in accordance with technical specification (T.S.) limiting condition for operation (LCO) 3.8.1.1.b, to ensure the operability of other power supplies to the emergency busses. Due to the number of start timing test failures, the testing periodicity for the "B" EDG was decreased from 31 days to 7 days, in accordance with T.S requirements.

On September 29, 1995, during surveillance testing of the "D" EDG, load swings developed approximately four hours into the 24 hour load test. When the load swings exceeded the procedural band for maintaining load, the test was terminated, and the "D" EDG was declared inoperable. In accordance with T.S. LCO 3.8.1.1.b, the other EDGs were tested, and "B" EDG once again failed its timing test, resulting in 2 EDGs being declared inoperable. T.S. LCO 3.8.1.1.e requires, among other actions, returning one of the inoperable units to operable status within 2 hours. Again, numerous starts were conducted for tuning the governor of "B" EDG to meet the timing criterion, resulting in the 2 hour limit being exceeded.

SEPTEMBER 29, 1995 FAILURE

During the 24 hour endurance test of "D" EDG on September 29, oscillations in the load developed approximately four hours into the run. The oscillations increased in size until they exceeded the allowable load range specified in the surveillance procedure. At this point, the test was terminated, and the EDG declared inoperable. During a subsequent run for troubleshooting, the EDG tripped and locked out on generator differential current. The problem was traced to a failed diode selector switch in the voltage regulator circuit.

PREVIOUS "D" EDG FAILURES

January 13, 1994 - "D" EDG failed its monthly operability test due to load swings of approximately 1000kW. The load swings were attributed to sticking fuel racks resulting from inadequate lubrication. The fuel racks on the other EDGs were inspected and found to be less than fully lubricated. The condition was corrected, and other potential causes were further evaluated. No other contributing conditions were identified. The monthly operability load test was successfully completed after lubricating the fuel racks.

February 10, 1994 - "D" EDG again failed its monthly operability test due to load variations which control room operators were unable to stabilize. Instrumentation of the control circuits did not identify any malfunctions of the governor system. Discussions by system engineering personnel with their counterparts at other facilities identified several other potential causes. The problem was subsequently identified to be fluctuations in the output of the isochronous droop relay (IDR). The IDR controls the operating mode of the EDG by selecting either isochronous mode (constant frequency) or droop mode (frequency decreases with load). Droop mode is only used when the EDG is tested. For accident situations, isochronous mode is automatically selected. The IDR failure was repeated during bench testing. The IDR was replaced, and surveillance testing of the "D" EDG was satisfactorily completed on February 17, 1994.

3.0 RELIABILITY TRACKING PROGRAM

The inspector reviewed the test success/failure tracking data for all 4 Hope Creek EDGs, and independently calculated reliability levels for each unit. The data is kept in a spreadsheet format by an engineer in the performance group. The number of start and load/run attempts and failures are recorded by month. The guidance provided in Regulatory Guide 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants," was used to evaluate the validity and success criteria for the start and load tests. The inspector also considered additional guidance provided to PSE&G by the NRC Office of Nuclear Reactor Regulation on October 11, 1995, regarding the appropriate use of the 10 second timing criterion for EDG start.

Based on the Reg Guide 1.108 success criteria (≥50% load for ≥one hour), the load test for the "D" EDG on September 29, 1995 constitutes a valid successful test. This is due to the EDG carrying full load for approximately 4 hours.

The supplemental guidance on interpreting T.S. start timing criteria stated that the 10 seconds is to the time at which the EDG is ready for loading, not until the time the governor stabilizes. This guidance, when applied to the numerous start timing failures of the "B" EDG in late September 1995, results in valid successful start tests.

The reliabilities calculated by the inspector are shown in the following table (target reliability is 0.95):

EDG	Last 20 Attempts Start	Last 20 Attempts Load/Run	Last 50 Attempts Start	Last 50 Attempts Load/Run	Last 100 Attempts Start	Last 100 Attempts Load/Run
A	1.0	1.0	1.0	1.0	1.0	1.0
B	1.0	1.0	1.0	1.0	1.0	1.0
C	1.0	1.0	1.0	1.0	1.0	1.0
D	1.0	1.0	1.0	0.98	0.99	0.99
All	1.0	1.0	1.0	1.0	1.0	1.0

In addition, the starting times from the monthly surveillance tests are recorded and tracked. The start times recorded for 1995 are consistent with the times recorded for previous years, and indicate no degradation of the engines. The System Manager is provided monthly printouts of EDG unavailability and reliability (both start and load/run) for the month, the year to date, and 3 and 12 month rolling averages. In addition, a chart is printed showing a graphic representation of the 12 month rolling average EDG unavailability, so that trends are easily seen. The graph also shows the Hope Creek unavailability goals to enable one to determine at a glance if they are being met.

4.0 MAINTENANCE

The inspector reviewed corrective actions for load test failures which occurred during the past 2 years.

Following the "D" EDG failure to carry load (valid failure) on January 13, 1994, PSE&G identified the probable cause to be inadequate lubrication of the fuel racks, and corrected the problem. In addition, the remaining EDGs at Hope Creek were checked for similar conditions. The remaining EDGs satisfactorily passed their load tests conducted in accordance with T.S. LCO 3.8.1.1. Following relubrication of the fuel racks, "D" EDG successfully passed its monthly operability test as well.

Following the "D" EDG failure to carry load (non-valid failure) on February 10, 1994, additional instrumentation was installed to monitor the governor control circuits. The cause of the failure was ultimately traced to The isochronous droop relay (IDR) in the control circuit, which selects either droop or isochronous mode operation. Following replacement of this relay, the load test was successfully completed. During subsequent testing, it was determined that the IDRs in the "A" and "B" EDGs were exhibiting noise on their outputs. The IDRs in all the engines were subsequently replaced as a short-tern corrective measure. These relays are now covered under the preventive maintenance program, which requires verifying proper function every year, and replacement every 5 years. The 5 year replacement interval is less than the time period since the plant started up, and so appears to be appropriate to prevent recurrence in the long term.

Following the "D" EDG failure during its endurance run on September 29, 1995, troubleshooting identified the cause to be a failed diode selector switch in the voltage regulator circuit. A new switch was procured, but was not installed due to defects discovered during receipt inspection. The switch has been returned to the manufacturer for evaluation. In the interim, a temporary modification has been implemented to hard wire the diode selection with a jumper (the switch position is not changed in service at Hope Creek). The EDG was successfully load tested with the temporary modification (jumper) in place. PSE&G is continuing to pursue the diode selector switch issues with the EDG supplier (Colt - Fairbanks).

5.0 CONCLUSIONS

The EDGs at Hope Creek are well maintained and are meeting their target reliability goals. Unavailability, while higher than assumed in the IPE, is generally meeting the goal. The repeated start timing test failures on the "B" EDG in September, 1995, appear to be due to an inappropriate acceptance criterion implemented in mid-September, and not to any degradation of the EDGs themselves. The Load/run failures experienced on the "D" EDG during the past 2 years are from different causes, and have been appropriately evaluated and corrected. In addition, the failures were evaluated for applicability to the other engines, and testing was conducted to determine if the condition existed. When problems were identified, they were corrected.

6.0 EXIT MEETING

The results of this inspection were discussed with the licensee by telephone on December 13, 1995.

ATTACHMENT 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION I

DOCKET/REPORT NOS.	50-354/95-17
LICENSEE:	Public Service Electric and Gas Company
FACILITY:	Hope Creek Nuclear Generating Station
INSPECTION AT:	Hancocks Bridge, New Jersey
INSPECTION DATES:	October 23-27, 1995

INSPECTOR: James Noggle 11/14/95

James Noggle, Sr. Radiation Specialist
Radiation Safety Branch
Division of Reactor Safety

Date

APPROVED BY: 11/15/95

John R. White, Chief
Radiation Safety Branch
Division of Reactor Safety

Date

DETAILS

1.0 INDIVIDUALS CONTACTED

1.1 Principal Licensee Employees

T. Cellmer, Radiation Protection Manager, Hope Creek
T. DiGuiseppi, Radiation Safety Manager, Services
R. Gary, Senior Radiation Protection Supervisor, Hope Creek
J. Gomeringer, Radiation Safety Specialist, Services
J. Kepley, Nuclear Quality Assurance Engineer
E. Lawrence, Quality Assurance Engineer, Salem
K. Maza, Chemistry/Health Physics/Radwaste Manager, Hope Creek
C. Munzenmaier, General Manager, Nuclear Operations Services
D. Parks, Radiation Protection/Chemistry Training Manager
R. Ritzman, Licensing Engineer, Hope Creek
J. Russell, Radiation Safety Specialist, Services
E. Villar, Licensing Engineer, Salem

1.2 NRC Employees

C. Marschall, Senior Resident Inspector, Salem
S. Morris, Resident Inspector, Hope Creek

The above individuals attended the inspection exit meeting on October 27, 1995.

The inspector also interviewed other individuals during the inspection.

2.0 PURPOSE OF INSPECTION

The purpose of this inspection was to review implementation of the solid radwaste/transportation program at the Salem Nuclear Generating Station.

3.0 AUDITS AND SURVEILLANCES

The inspector reviewed the licensee's program for auditing and providing independent surveillances of the solid radwaste/transportation program. The latest audit, No. 94-152, was performed on May 16 through June 1, 1994 (a Technical Specification biennial requirement). This audit was previously reviewed by the inspector during a previous inspection[1]. The previous inspection indicated that this audit was limited in technical depth and that there were no technical specialists included on the audit team due to scheduling conflicts.

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[1] NRC Inspection Nos. 50-272/94-20; 50-311/94-20; 50-354/94-20 conducted on August 29 through September 2, 1994.

The inspector reviewed the licensee's surveillance program with respect to the radwaste/transportation program. The licensee indicated to the inspector that the past station practice of providing an independent quality control surveillance of each radioactive shipment leaving the station had been modified in July of 1995. At that time, quality hold points were developed that only required partial surveillance of radwaste shipments and exempted radioactive material shipments that were not shipped directly to a low-level radioactive waste disposal facility. The inspector questioned the reduction of management oversight of this program area. After some discussion and review by the licensee, the licensee determined that they would provide quality surveillance reviews for all radioactive material/waste shipments except for limited quantity shipments. The licensee also indicated the intention to develop a methodology to allow the radwaste shipping group to provide their own self-assessment of shipment preparation and documentation to effect the same result. No safety issues or violations were identified.

4.0 TRAINING

The inspector reviewed the training program with respect to NRC IE Bulletin 79-19 requirements. Hope Creek Nuclear Generating Station had two individuals that were authorized to ship radioactive materials/wastes. The inspector checked the training records of each of these individuals and found that each had successfully completed a two-day vendor-supplied course provided on February 6-7, 1995. The inspector reviewed the course materials and the final examination and found that the important shipping regulations were accurately represented and covered. Final examination grades of greater than 70% were satisfied by each of the authorized shipping personnel. The inspector discussed with the licensee the recent publication of the revised NRC and Department of Transportation shipping regulations (10 CFR 71 and 49 CFR 171-178, respectively) and the licensee indicated intentions to retrain the applicable personnel on these regulations in the near future. No discrepancies related to training were noted.

5.0 RADWASTE PROCESSING

The Hope Creek Nuclear Generating Station generated a total of 65 cubic meters of solid radwaste during 1994 and had generated a total of 65 cubic meters from January through September of 1995. The licensee has shown a continuing downward trend in radwaste generation since 1988 when 303 cubic meters of radwaste were produced. Increases in radwaste generation this year resulted from an April 5, 1995 contamination event. Additional contributions will result from the November/December 1995 refueling outage.

Hope Creek Generating Station produces reactor water cleanup resin wastes and utilizes a vendor-supplied dewatering service to ensure the resins do not contain more than 1% free standing water. The floor and equipment drain liquid wastes were previously processed through mechanical filters with the backwash sludge processed through the asphalt-extruder solidification system. Due to system throughput and filter septum failures, the floor and equipment drain filters were in the process of being changed back to a powdered resin septum precoat configuration during this inspection. When completed, the radwaste filter and water cleanup systems will be restored to the original facility design configuration. The original radwaste system design incorporated two waste evaporators and one crystallizer to reduce the water content of the spent resin filter media. The resulting waste sludges (except for the reactor water cleanup resins) were solidified through the asphalt-extruder system in a batch mode process producing a bituminous/waste matrix stable waste form in 55-gallon drums. At the time of the inspection, the waste evaporators and the crystallizer were shutdown. The two waste evaporators have indications of cracking and may require extensive repairs. Bituminous waste drums had not been produced since July 1995. The licensee had contracted with a vendor service to provide resin dewatering services, which would then be shipped directly to the Barnwell Low Level Radioactive Waste Disposal Facility for burial. The licensee indicated that the entire Hope Creek solid radwaste processing system was under engineering review to determine other radwaste processing technology options.

The bituminous waste product was produced as the waste sludge material was pumped from the waste evaporators/crystallizer into the asphalt-extruder and was heated by steam to drive off all remaining liquid and premelted asphalt was mixed with the dewatered waste sludge. The resulting mixture was poured into 55-gallon drums. The licensee utilized a closed circuit television camera system to observe the waste material as it flowed into the waste drums in order to verify that the waste material was flowing out of the asphalt-extruder properly and to verify that each waste drum was completely filled. The waste drums were subsequently capped and sealed in a remotely operated drum capping aisle. The filled waste containers were temporarily stored in an adjoining drum storage vault until transferred to the onsite low level radwaste storage facility.

The inspector reviewed the licensee's bituminous waste processing documentation. Each batch was sampled and analyzed by Chemistry to ensure proper pH, that there was negligible oil content in the waste material, and to determine the correct asphalt addition ratio. The inspector reviewed selected waste sludge batch sampling records, asphalt sampling analytical records, waste-to-asphalt mixture ratio determination records, and control and accountability records for these radwaste storage drums. In addition, asphalt-extruder temperature parameter controls were reviewed. The inspector determined that there was excellent documentation of the records reviewed and indicated that the appropriate process control parameters were met as specified in the Hope Creek Station Process Control Program. No discrepancies were noted with respect to producing a solid waste form.

6.0 RADWASTE CHARACTERIZATION

The characterization of radioactive shipments is determined through periodic sampling of the various solid radwaste streams and offsite radiochemical analysis. From these analytical results, the licensee specifies the difficult to measure isotopes (non-gamma emitting radionuclides) through the use of scaling factors tied to an easily measurable radionuclide such as cobalt-60. The inspector reviewed Procedure HC.RP-TI.ZZ-0902(Q), Rev. 3, "Radioactive Waste Sampling and Classification." The inspector also reviewed the licensee's latest radioactive waste stream radiochemical analytical results. The procedure depicted an acceptable sampling/characterization methodology. Analytical results were reviewed for the following waste streams: waste sludge, reactor water cleanup resin, radwaste bead resin, and crystallizer bottoms. The licensee indicated that miscellaneous contaminated trash, termed dry active waste (DAW), was characterized utilizing the waste sludge analytical results. The inspector reviewed the adequacy of the waste sludge waste stream as representing DAW.

The licensee provided the inspector with the gamma isotopic analysis results from 12 swipe samples taken from 6 representative plant areas during the third quarter of 1995. The inspector averaged these results and compared them with the gamma emitting isotopes obtained from the waste sludge analytical results as shown below.

	Mn-54	Co-60	Zn-65	Cr-51	Fe-59	CO-58	Other
Swipe Composite	60%	28%	5%	3%	2%	1%	1%
Waste Sludge	32%	10%	55%	2%	0.6%	0.4%	
Ratio Factor	1.9	2.8	-11	1.5	3.3	2.5	

Based on the above review of gamma emitting isotopes, the inspector determined that there was a significant variation in the radioisotope mixture to warrant a separate DAW waste stream analysis. The licensee had acquired the swipe sample data in order to evaluate this need and stated that during the November-December 1995 refueling outage, swipe samples would be obtained in the major station work areas and that the swipe sample composite would be sent offsite for a complete radiochemical analysis in order to establish a distinct DAW waste stream, which will be used to characterize all future DAW shipments. The inspector determined that the licensee has taken the appropriate actions, although the licensee has been slow to make this separate waste stream determination.

All of the licensee's current solid radioactive waste streams had been sampled and analyzed within the past 2 years as required. No discrepancies were noted in the radioactive waste stream sampling and waste characterization area.

7.0 TRANSPORTATION

The inspector observed one radioactive waste shipment from the Hope Creek Nuclear Generating Station (described in this report) and one radioactive material shipment from the Salem Nuclear Generating Station (described in NRC Inspection Nos. 50-272/95-19; 50-311/95-19) during the inspection.

On October 25, 1995, the licensee made the final preparations and shipped an exclusive-use shielded cask shipment containing 21, 55-gallon drums of bituminous waste material. The inspector observed the remote loading operation in the onsite radwaste storage facility, the final survey of the transport vehicle, and reviewed the shipping records pertaining to the shipment. The inspector observed a well executed cask loading operation involving the remote pickup and landing of three pallets of waste drums into the shielded transport cask. The licensee accounted for each bituminous waste drum by remote closed circuit television camera observation and managed the crane operations without any rigging assistance. A quality control inspector observed the cask lid closure bolting and torque sequence and ensured a calibrated torque wrench was utilized. Radioactive Material placards were attached on all 4 sides of the transport vehicle and a final radiation survey was conducted by the licensee. All shipping records were completed and emergency directions were given to the driver with his signature attesting to his understanding and compliance with those directions. Approved transport routes were discussed with the driver and the shipment was allowed to leave Hope Creek Station. This was an efficient and well executed shipping evolution. No discrepancies were noted by the inspector.

The following Hope Creek radioactive waste/material shipment records were reviewed by the inspector.

Shipment No.	Activity (Ci)	Volume (ft^3)	Type
95-04	4E-7	1230	DAW
95-05	6E-9	---	CRD Pump
95-07	1.97	157.5	Bead Resin
95-09	4.2	157.5	Bead Resin
95-17	44.6	105	Powdered Resin
95-21	1.2E-5	620	DAW
95-24	0.067	2460	DAW
95-31	1.972	412.2	Bead Resin
95-33	6.0	157.5	Powdered/Bead Resin
95-36	2E-6	1500cc	Samples
95-39	1E-9	15	Safety Relief Valves
95-42	0.082	630	Laundry

The inspector questioned the licensee's derivation of total activity of shipment number 95-39. The licensee utilized the waste sludge waste stream radiochemical analytical results to characterize the shipment based on swipe samples taken on the safety relief valves and a total surface area determination. The shipping records did not provide an indication of how the total surface area had been determined. Other contaminated equipment shipments were reviewed and some assumptions were recorded on these shipments, but none included enough information to indicate how the total surface area had been calculated. The inspector determined that the complete documentation of surface area calculations is an area that could be improved.

All other shipping records were determined to be complete and all were determined to meet the applicable requirements of 10 CFR Parts 20, 71 and 49 Parts 171-178. The inspector verified that all consignee licenses were on file as required. The inspector reviewed the following transportation procedures.

HC.RP-TI.ZZ-0909(Q), Rev.6, "Shipment of Radioactive Materials Excluding Waste for Burial"
NC.RP-TI.ZZ-0915(Q), Rev. 0, "Shipment and Receipt of Laundry"
NC.RP-TI.ZZ-0930(Q), Rev. 0, "Interim Low Level Radwaste Transfer and Storage"

The procedures reviewed, were of excellent quality with no discrepancies noted. No safety concerns or violations were identified.

8.0 ONSITE RADWASTE STORAGE

The Hope Creek radwaste building contains an inplant shielded high radiation storage area where processed solid waste containers were stored. The licensee maintained a status board in the radwaste control room that indicated the location of each waste container in this storage area. At the time of this inspection, 81, 55-gallon drums containing solidified bituminous waste material were in storage. The licensee was in the process of transferring all of the remaining waste drums to the onsite radwaste storage facility for staging and preparation for shipment to the Barnwell Low Level Radioactive Waste Disposal Facility.

The licensee completed construction and began operation of an onsite radwaste storage facility in late 1994. This facility, Building 41, was designed for the storage of solid radioactive wastes as generated by both Hope Creek and Salem Stations during time periods when a commercial disposal facility was not available. This facility is 68' X 266' and consists of a concrete and steel structure designed to hold approximately 1870 cubic meters of radwaste. This facility consists of a 2-foot thick concrete walled internal vault area for the higher dose rate wastes and the outside walls of Building 41 are 1-foot thick concrete shielding. An overhead crane is operated remotely from a shielded control room area utilizing closed circuit television camera. In addition, the crane hooks mate with radwaste container handling pallets and strongbacks without the need for rigging personnel in the area.

At the time of this inspection, the licensee was in the process of emptying the Building 41 onsite radwaste storage facility. Remaining radwaste stored in the facility consisted of approximately 44, 55-gallon drums of bituminous waste media. In addition, Salem radwastes included 1 polyethylene liner of spent DTI resin and 8 boxes of DAW ash/compacted wastes returned from SEG. The inspector observed a high degree of activity directed to shipping all remaining radioactive wastes currently in storage at both Hope Creek and Salem Stations. An area for enhancement was suggested to the licensee. Inside

Building 41, there currently is no status board or other reference available to determine the building waste inventory or the location of individual waste containers in the building. A waste location/inventory reference located in the facility would improve the coordination of waste container movement activities conducted by crane operators and support personnel. In summary, the radwaste storage onsite was well managed and controlled. No safety concerns or violations were identified.

ATTACHMENT 3 - ENFORCEMENT CONFERENCE - LIST OF ATTENDEES

NOVEMBER 6, 1995

U.S. NUCLEAR REGULATORY COMMISSION (NRC)

T. Martin, Regional Administrator
W. Kane, Deputy Regional Administrator
J. Wiggins, Director, Division of Reactor Safety (DRS)
L. Nicholson, Chief, Reactor Projects Branch 3, Division of Reactor Projects
R. Summers, Senior Resident Inspector, Hope Creek
J. Linville, Acting Director, Division of Reactor Projects
S. Morris, Resident Inspector, Hope Creek
J. Shannon, Reactor Engineer, Electrical Branch
A. Blough, Region I, Acting Deputy Director, DRS
K. Smith, Regional Attorney
J. Stolz, Director, Project Directorate I-2, Nuclear Reactor Regulation (NRR)
J. Joustra, Senior Enforcement Specialist
D. Jaffe, Hope Creek Project Manager, NRR
W. Dean, Regional Coordinator, Office of Executive Director for Operations
J. Trapp, Team Leader, NRC
T. Walker, Senior Operations Engineer

OTHERS

S. Singh, N.J. Department of Environmental Protection
T. Kolesnick, N.J. Department of Environmental Protection
P. Robinson, Winston & Strann

PUBLIC SERVICE ELECTRIC AND GAS COMPANY (PSE&G)

L. Eliason, President and CNO, Nuclear Business Unit (NBU)
L. Storz, Senior Vice President Operations, NBU
J. Benjamin, Director, Quality Assurance, Nuclear Safety Review and Nuclear Licensing
M. Reddemann, General Manager, Hope Creek Operations
H. Hanson, Operating Engineer
T. Hopely, Nuclear Technician
R. Ficarra, Nuclear Equipment Operator
D. Sourber, Nuclear Controls Operator
B. Sebastian, Nuclear Technical Supervisor
W. Mattingly, Hope Creek QA Supervisor
K. Krueger, Senior Nuclear Shift Supervisor
M. Mohney, Senior Nuclear Shift Supervisor
M. Pfizenmaier, Nuclear Shift Supervisor
J. Hawrylak, Senior Engineering Technician
J. Clancy, Manager, Hope Creek Technical Department
C. Brennan, Senior Staff Engineer
C. Manges, Jr., Licensing Engineer

ATTACHMENT 4 - HOPE CREEK REFUELING OUTAGE MEETING - LIST OF ATTENDEES

NOVEMBER 6, 1995

U.S. NUCLEAR REGULATORY COMMISSION (NRC)

T. Martin, Regional Administrator
W. Kane, Deputy Regional Administrator
J. Wiggins, Director, Division of Reactor Safety (DRS)
J. Linville, Acting Director, Division of Reactor Projects (DRP)
L. Nicholson, Chief, Reactor Projects Branch 3, Division of Reactor Projects
J. Stolz, Director, Project Directorate I-2, Nuclear Reactor Regulation (NRR)
G. Barber, Project Engineer, DRP
W. Dean, Regional Coordinator, Office of Executive Director for Operations, NRR
J. Noggle, Senior Radiation Specialist, DRS
J. Shannon, Reactor Engineer, Electrical Branch
S. Morris, Resident Inspector, Hope Creek
T. Walker, Senior Operations Engineer
V. Dricks, Field Public Affairs Officer
D. Jaffe, Hope Creek Project Manager, NRR

PUBLIC SERVICE ELECTRIC AND GAS COMPANY (PSE&G)

L. Eliason, President and CNO, Nuclear Business Unit (NBU)
L. Storz, Senior Vice President Operations, NBU
J. Benjamin, Director, Quality Assurance, Nuclear Safety Review and Nuclear Licensing
M. Reddemann, General Manager, Hope Creek Operations
C. Florentz, Nuclear Public Information Representative
D. Smith, Principal Engineer, Nuclear Licensing
T. Kirwin, Refueling Outage Manager

OTHERS

K. Kille, Delaware Emergency Management Agency
S. Singh, N.J. Department of Environmental Protection
T. Kolesnick, N.J. Department of Environmental Protection
M. Gray, Today's Sunbeam
P. Milford, News Journal
P. Robinson, Winston and Strann

HOPE CREEK SHUTDOWN COOLING BYPASS EVENT

ENFORCEMENT CONFERENCE

NOVEMBER 6, 1995

AGENDA

I.	Introduction	L. Eliason
II.	Overview of Event	H. Hanson
III.	Operator Performance	M. Reddemann
IV.	Post-Event Review	M. Reddemann
V.	Communications With NRC	L. Storz
VI.	Closing Remarks	L. Eliason

<u>Introduction</u>

No Dispute Concerning Basic Facts of Shutdown Cooling Bypass Event

PSE&G Management Understands the Significance of the Event and Takes the Matter Very Seriously

The Event and More Recent Problems Resulted in Focusing Analysis on Weak Areas, Particularly Operations Department Performance (Individual & Group)

Extensive Corrective Actions Have Been Implemented or Initiated Since the Event

Near-Term Operational Performance Demonstrated that Additional Strong Management Actions were Warranted -- Actions Have Been Initiated

PSE&G Management is Committed to Solving the Performance Problems Through <u>All</u> Means Available

PSE&G Management is Also Committed to <u>Promptly</u> and <u>Fully</u> Communicating <u>All</u> Appropriate Matters to the NRC

Summary Analysis of Event

Action	Result	Missed Opportunity
Forced Shutdown Initiated	Complied With CREF Action Statement	Failure To Promptly Resolve Equipment Problems
The B Discharge Was Cracked Open and Left Open	2000 GPM Bypass Flow	Failure to Comply With Procedures; Recognized Bypass Flow But Concluded It Was Not An Issue Based On Temperature Indication; Failure of the NCO to Communicate With Shift Management
SNSS/NSS Attempted To Close Valves; A Valve Was Closed; B Valve Was Opened Further	Bypass Flow Increased to 4000 GPM	Failure To Avoid Aggravating The Situation Due To Mis-Understanding Of Valve Actuator Operation
Operators Entered The Drywell	Manually Cracked The A Valve Open; Reported Condensation Upon Exiting	Failure to Properly Heed Indications
Operators Attributed Slow Increase In Drywell Leak Detection to a Cooling Coil Leak	No Action Taken	Failure to Properly Heed Indications/Instruments; Poor Assessment of Integrated Plant Conditions
High Pressure Readings On Reactor Pressure Channels Were Attributed to Either Elevation Head or "Zero" on a 1500 PSIG Scale	No Action Taken	Failure to Properly Heed Instruments; Poor Assessment of Integrated Plant Conditions
Plan to Close the B Valve Canceled For Safety Reasons	Action to Close Valve Was Delayed	Poor Communication Between the NSS/NCOs and the SNSS Resulted In A Decision Without Important Information
AR Was Written and Operability Determination Was Inadequately Addressed	Operability Concern Was Not Adequately Characterized	Failure To Recognize Mode Change
Assistance from Other Departments Was Not Requested Throughout The Event	Expertise of Other Departments Was Not Used	Failure to Request Assistance from Other Departments

Missed Opportunities By Individuals

	Failure to Comply With Procedures	Failure to Believe Indications	Failure to Communicate Including Turnover	Failure to Adequately Diagnose Plant Conditions	Failure to Utilize Other Resources
Senior Nuclear Shift Supervisors	✖		✖	✖	✖
Nuclear Shift Supervisors/ Shift Technical Advisor	✖	✖	✖	✖	✖
Nuclear Controls Operators	✖	✖	✖	✖	✖
Equipment Operators			✔	✖	

- Individual Failures
- Crew (Team) Failures

- 3 Levels of Supervision Did Not Respond To EO's Information

Implications of On-Shift Failures
During Shutdown Cooling Bypass Event

Key Failures By Individuals

Day Shift: (1) Decision Not to Follow Procedures

(2) Communications Breakdown -- At All Levels

Night Shift: (1) Shift Turnover Failed

(2) Failure to Diagnose Problems -- At All Levels

(3) Proceeding In the Face of Uncertainty

Implications To The Operations Department

- Lack of A Strong Operating Ethic
- Poor Safety Consciousness (Including Lack of Conservative Decision-making)
- Acceptance of Mediocrity
- Tolerance of Equipment Problems
- Inadequate Knowledge and Skills
- STA Function Inadequately Implemented

Causes/Contributing Causes of Poor Operator Performance

Causes

Failure to Follow Procedures

Proceeding in the Face of Uncertainty

Poor Communications On-Shift

Ineffective Oversight by Operations Department Management

Contributing Causes

Ineffective Operating Experience Feedback Program

Inadequate Operator Training

Inadequate Procedures

Tolerance of Long-Standing Equipment Problems

Lack of Self-Assessment

Post-Event Review Efforts & Specific Corrective Actions

Initial Review Efforts

Root Cause Analysis For Action Request Performed By Night Shift SNSS

Technical Department Evaluation Of Operability/Reportability For Action Request

QA/SRG Evaluations

Independent Team Evaluation of Shutdown Cooling Bypass Event

Selected Corrective Actions
In Response to Shutdown Cooling Event

Restated and Reinforced Management Expectations on Procedure Compliance

Revised Applicable Operating Procedures

Modified Operator Training

Clarified Guidelines/Expectations For Investigation of Significant Events

Enhanced Guidance on Reporting Requirements

Post-Event Review Shortcomings By Organization

	Poor Internal Communications	Non-Conservative Reporting	Poor Operability Determination	Failure To Effectively Raise Issue To Highest Level	Recognition of Significance of Event
Operations Department	✖	✖	✖	✖	✖
Technical Support	✖		✖	✖	✖
Quality Assurance	✖	✔		✖	✔
Safety Review Group	✖	✔		✖	✖
Licensing	✖	✖		✖	✖

- **Over-Analyzed Problem**
- **Lack of Leadership**
- **Conditioned Response**
- **Ineffective Communications**
- **Abdication of Responsibility by Operations**
- **Failure to Effectively Raise Issues**

Broader Actions

Assessment of Past Operations Department Performance

Assessment of Past Shutdown Cooling Events

Operating Experience Program Improvement Plan

Actions In Response To
Rod Mis-position & Tagging Incidents

Immediate Actions

Removed 3 SROs and 2 ROs From Shift

Replaced the Removed Individuals With More Capable Performers

Removed Operations Manager

Previously Removed Night Shift SNSS Involved in SDC Event

Using Human Error Reduction Experts On-shift

Additional Actions

New Operations Manager Will Be Hired

SROs and EOs Will Be Hired From Outside the Company

Strengthen Operations Requalification Training

Implement Departmental Self-Assessment Process

Enhancing Communications

Our *Expectation* Is To Make the "right" communications decision promptly and effectively

Communications Initiatives

Senior Management (CNO and team) buy-in to open, honest communications as part of NBU vision

- Bi-weekly managers meetings
- Communication of expectations and results

Reengineering of communications process

- Full link to Enterprise corporate communications
- Development, implementation of communications strategy for key internal, external stakeholders
- Initiatives now under way; effectiveness will be measured

Communications Process Requires Feedback

Closing Remarks

We Have Made Substantial Progress In Understanding and Addressing Our Performance Problems

We Have Initiated Strong Intervention To Cause A Step Change In Operations Performance

We Are Developing Short-and-Long-Term Improvement Plans to Support The Step Change

We Believe The Key To Our Success Is Assuring Proper Leadership for the Operations Department

We Will Continually Reassess Our Progress To Assure We Remain On The Right Track