U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-354/95-19

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: November 9, 1995 - December 21, 1995

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Inspection Summary:

This inspection report documents inspections to assure public health and safety during day and backshift hours of station activities, including: operations, radiological controls, maintenance and surveillance testing, emergency preparedness, security, engineering/technical support, and safety assessment/quality verification. In addition, three stand alone feeder reports are attached to this report covering ISI program review, outage radiation protection, and follow up on pressure locking/thermal binding of motor operated gate valves. The following Executive Summary delineates the inspection findings and conclusions.

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EXECUTIVE SUMMARY

Hope Creek Inspection Report 50-354/95-19

November 9, 1995 - December 21, 1995

OPERATIONS

Pre-evolution briefings were observed to have better detail and were more frequently used than has been the practice in the past. Senior licensed operators were observed as providing more and better direct supervision of plant activities and in ensuring that plant conditions were acceptable. The inspectors concluded that these observations indicated that improvements were continuing in both communications and ownership. Operator performance during the unit shutdown was very good. Management oversight of control room activities during the shutdown was excellent. (See Section 2.2 of this report for details.)

While procedure adherence was generally good, two examples of procedure violations were identified by the inspectors. However, these violations involved procedures that had either less than clear guidance or were inaccurate. (See Section 2.4 and 7.1 of this report for details.)

During current refueling operations a number of issues were identified by the licensee that indicated past refueling practices were weak, including: a mis-oriented fuel bundle in the core that existed throughout the last operating cycle that; a number of tools that were found in the bellows area of the refuel cavity; and, a faulty LPRM bending tool that led to asymmetric bending of removed LPRM strings. Current corrective actions for these issues were assessed as acceptable. In general, current refueling activities were assessed as both safe and conservative. The misoriented fuel bundle issue is being treated as a Non-Cited Violation. (See Section 2.3 of this report for details.)

A special NRC assessment of refueling outage controls was completed and concluded that while recent emerging workload and new management expectations had led to the outage scope being much greater than originally planned, sufficient management oversight and employment of outage risk techniques were providing reasonable assurance that the plant was being maintained safe. (See Section 2.5 of this report for details.)

MAINTENANCE/SURVEILLANCE

Improvements were noted in both safety tagging and work control performance. Also, in general, ongoing work activities that were observed were conducted appropriately and in accordance with plant procedures. However, examples were identified that indicated weaknesses, including: ineffective corrective actions as committed to in an LER regarding special handling of work on valve actuators with live 125-volt DC; poor planning and coordination of corrective maintenance on the C emergency diesel generator; and, an event in which a mobile crane impacted the 500 KV transmission line from the main power transformers to the Hope Creek switchyard. (See Section 3.2 of this report for details.)

Certain shutdown surveillance activities were not properly established in operating procedures which led to the violation described in the Operations Section. Licensee reviews identified additional similar weaknesses in implementing other shutdown surveillance requirements. (See Section 2.4 and 7.1 of this report for details.)

ENGINEERING

The licensee's investigation and resolution of problems with an event involving the B emergency diesel generator was considered good, with thorough root cause assessment of identified problems. The station's engineering backlog was assessed with an overall conclusion that the backlog was not significant, and was appropriately monitored and controlled. (See Section 4.1 of this report for details.)

An in-office, specialist inspector review and working-level meeting discussing the licensee's evaluation of MOV susceptibility to pressure locking and thermal binding was conducted on October 16, 1995. The engineering work incorporated into the evaluation was assessed by the NRC as comprehensive. (See Attachment 3 of this inspection report for details.)

An NRC review of the licensee's inservice inspection program found the timeliness of the 10-year long-term inspection program implementation and coherence with code and regulatory requirements to be appropriately pursued. Review of the long-term inspection plan, inservice inspection reports, supporting documents, and interview of the senior ISI engineer found the program to be consistent with code requirements and the ISI engineer knowledgeable and exhibiting a sense of ownership of his area of responsibility. The results of the inspection program revealed a flaw in the core spray system piping and several loose locknuts in piping support struts. The core spray system was repaired, and the root cause investigation of loose locknuts is in process to provide a basis for corrective action in addition to expanding the inspection sampling population. A missed surveillance was discovered through self-assessment of performance. Corrective actions to improve monitoring of the required surveillance intervals appear to be adequate. The evaluation and disposition of findings stemming from the licensee's visual inspection of reactor vessel internals were reviewed by the inspectors and found consistent with station procedures and reactor vendor recommendations.

The Types B and C leak-rate testing program was assessed as being implemented effectively under the direction of a responsible engineer, who provided excellent controls to ensure that all components and penetrations were tested in accordance with schedule. A review of the Hope Creek erosion/corrosion piping degradation evaluation program by the inspectors found that the program was implemented in accordance with the monitoring guidelines using the evaluation of pipe wall thinning in accordance with techniques used in the Checmate/Checworks computerized pipe degradation evaluation system. The inspectors found the results of the monitoring program to be well documented and easily retraceable for future comparison of the predicted trend with the actual pipe degradation progression.

The inspectors found two cases of deficient corrective action implementation that collectively indicate an apparent violation of regulatory requirements, including: licensee performance in implementing corrective action in the case of SACS piping low temperature operation; and, residual heat removal system piping repeated snubber failures without definitive root cause determination nor implementation of recommended corrective actions. Repeated SACS system operation below minimum design basis temperature occurred over the last decade without supporting analysis proving acceptability. In the case of RHR, the licensee experienced a series of piping snubber failures over the last three operating cycles and neglected to follow recommendations to ameliorate the hydraulic forces in the system causing the damage. (See Attachment 1 of this report for the inspection details of the IST program and NRC concerns relative to these ineffective corrective actions.)

PLANT SUPPORT

During routine tours of the facility, the inspectors observed that: radiation protection requirements were being properly implemented; that physical protection requirements and coordination with offsite law enforcement agencies was maintained; and, that station cleanliness and material conditions were observed to be very good. (See Section 5.0 of this report for details.)

An NRC specialist inspection of the radiation controls program was conducted during refueling outage conditions. Areas reviewed included outage radiation controls organization staffing, contractor radiation protection (RP) technician training, external exposure control, internal exposure control, and exposure reduction initiatives. In general, the radiation controls program was determined to be strong. The as low as is reasonably achievable (ALARA) program was moderately effective. The ALARA program was not aggressive in its approach to reducing dose rates in the major dose contributing areas of the plant. Minimal benefit from the shielding program area was identified early in the inspection; subsequent shielding efforts were made during the inspection that indicated an excellent response capability of the radiation controls organization. (See Attachment 2 for inspection details regarding the review of the radiation controls program.)

SAFETY ASSESSMENT/QUALITY VERIFICATION

NRC review of the Outage Completion Plan, including activities of the Outage Review Committee were considered excellent, especially in providing priorities for outstanding or backlogged work. Continual reviews of the licensee's corrective actions program reveals that improvement has occurred in problem identification and management oversight of the timeliness of problem resolution. However, the problem closure backlog continues to be a noted concern. QA/NSR activities were assessed as providing good indicators to management regarding areas of weak performance. (See Section 6.0 of this report for details.)

Inspector review of a recent audit of the ISI program revealed that quality assurance personnel, through excellent preparation and extensive knowledge of visual examinations, identified an area of weakness in the reactor vessel internals inspection that resulted in a more complete examination of tack welds and finding other cracked tack welds. The inspectors concluded that the quality assurance program at HCGS strengthened the ISI program. (See Attachment 1 of this report for inspection details regarding the ISI program.)

TABLE OF CONTENTS

DETAILS

1.0 SUMMARY OF OPERATIONS

Hope Creek began the inspection period at about 90% power in an end-of-operating cycle coastdown. The unit was shutdown on November 11, 1995 as a result of a technical specification required shutdown due to an inoperable primary containment when a surveillance test of drywell vacuum breakers failed. The unit was scheduled to be shutdown that same day to commence the sixth refueling and maintenance outage. After the shutdown, the refueling outage commenced. The unit remained shutdown at the end of the period and restart plans were still under evaluation. It was anticipated that the outage would end in mid-February 1996.

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 PS&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 20 hours of deep back-shift inspections.

2.2 Operations Ownership Assessment

As has been characterized in previous routine NRC inspections reports, the inspectors remained concerned at the increased "arrival rate" of significant issues that either directly or indirectly affected station operation. The large number of problems that occurred throughout the report period continued to challenge plant operators and station management; however, the inspectors noted that many of the significant issues raised were the direct result of an increased willingness on the part of all station personnel to critically evaluate systems, procedures and processes and document identified degraded conditions. Key evidence of the station's increased willingness and vigor to document discrepancies was the dramatic increase in the number of action requests generated over the last six months. As an example, control room operators identified a significant concern regarding the operability of the safety auxiliaries cooling system during a review of the system's design basis description in the final safety analysis report (see ENGINEERING).

With respect to operations ownership, the inspectors witnessed improvements in several areas. In particular, pre-evolution briefings for planned maintenance and testing were more frequent and more detailed. The inspectors observed a greater willingness on the part of senior operators to place holds on outage work when plant conditions did not appropriately support the work schedule. Shift supervisors spent more time in the field and focused more time on direct supervision of operator board manipulations, even for routine evolutions. Procedural adherence was good, and effective communications both in person and over radio circuits was sustained. Non-licensed operators demonstrated good awareness of plant conditions and on several occasions identified problems with equipment that went previously unnoticed. The assignment of an additional individual in the control room for the duration of the outage to monitor the function of shutdown cooling systems was considered a positive measure to enhance reliability.

Operators continued to demonstrate good performance during plant transient and abnormal conditions. For example, on November 26, 1995, with the plant in cold shutdown, the control room received indications of a grass intrusion at the service water intake structure. Operators entered the appropriate "abnormal" procedure to combat the event, during which the "D" service water subsystem was tagged out for maintenance, the "B" pump discharge strainer tripped on overload, and the "C" pump failed upon start (motor winding short). Prompt and effective response to the event minimized the impact and duration of the transient. Another example involved thorough pursuit of noted reactor cavity/equipment storage pit leakage, which resulted in the timely identification of a partially opened drain valve.

2.3 Plant Shutdown and Refueling Operations

The NRC provided extended control room observation during the unit shutdown for the sixth refueling outage. Around-the-clock coverage of the unit shutdown and cooldown to the cold shutdown condition occurred over a 48-hour period from November 10, through November 12, 1995. Additional frequent control room observations were made during the initial period of use of the shutdown cooling mode of operation of the RHR system. In general, the NRC concluded that the shutdown activities were well controlled and noted excellent management oversight of the activities.

Operators demonstrated a significant sensitivity to the loss of shutdown cooling events. Further improved computer driven displays allowed operators to focus on the most important parameters during shutdown. This display included reactor recirculation loop and jet pump flows, reactor coolant and vessel temperatures, pressure (with wide range indication (1 psig, 10 psig and 20 psig)) and water level and the residual heat removal (RHR) system shutdown cooling system parameters. This new display allows for close monitoring of the shutdown cooling mode of operation. Operators received training on watching for negative trends using this new display.

Generally speaking, all operations on the refuel floor during the outage were conducted in safe and conservative manner, and in accordance with established procedures. The inspectors directly witnessed core alterations from the refueling platform, which included observations of two shift turnovers, and did not identify any significant concerns. In fact, the inspectors noted excellent "three-way" communications between the senior reactor operators, the refueling hoist operators, and the control room. Conservative decision making with respect to fuel movement and positioning was evident as was the outstanding knowledge and experience levels of the individuals associated with the refueling.

The inspectors evaluated the implementation of the "tool control" program on the refuel floor and concluded that all materials entering and exiting the controlled area were adequately accounted for, despite evidence that the program was less than fully effective during previous outages. Specifically, just prior to flooding the reactor cavity during this outage, Hope Creek personnel identified several tools submerged in dirty/clouded water in the bellows region of the cavity just outside the reactor vessel. The inspectors deemed appropriate the licensee's plans to conduct a thorough search for foreign material (and removal) in the cavity region prior to vessel reassembly.

On November 30, 1995, operators transferring an asymmetrically bent local power range monitor (LPRM) string from the reactor cavity to the spent fuel storage pool lifted the LPRM close enough to the surface of the water to cause a momentary radiation field at the surface of the pool of 18 R/hr, resulting in refuel floor radiation monitors thirty feet away to reach alert levels (8.5 mrem/hr). No containment isolation signal was generated and no personnel on the refuel floor at the time of the event received a dose greater than 5 mrem. All activities on the refuel floor were halted by the senior reactor operator after the LPRM was safely stored in the pool. The primary cause of the event was attributed to a mechanical failure in the LPRM bending machine, resulting in its failure to fully lower prior to engaging the LPRM. All operating and radiological protection procedures associated with the handling of LPRM's were appropriately implemented. While the inspectors concluded that post-event root cause and corrective action development was very good, the apparent lack of consideration by refuel floor personnel for the potential consequences of handling asymmetrically bent LPRM strings after one had been identified was considered weak.

On December 12, 1995, during the conduct of core alterations, the refueling platform operators discovered a mis-oriented fuel bundle in the core which had existed since the previous refueling outage. No physical damage to the bundle was evident upon inspection and the bundle was immediately re-oriented to the proper position. Licensee analysis of the impact on the adjacent bundles that were intended for reuse during the upcoming operating cycle had not yet been completed at the conclusion of the report period, however, the licensee had committed to this corrective action. The licensee determined that no unusual levels of coolant activity were noted during the operating cycle that would be indicative of resultant fuel damage due to this error. The root cause(s) of the event were also yet to be determined, however the inspectors concluded that inadequate attention to detail (personnel error) and independent core verification during the last core reload (March 1994) were clearly contributing causes. Because this was identified by the licensee; was not significant, in that no fuel damage resulted from the error; was not a violation that could reasonably have been prevented by the licensee's corrective actions for previous similar concerns; was not the result of a willful act; and, would be corrected within a reasonable period of time, the NRC considered this to be a licensee identified non-cited violation.

2.4 Procedure Violations

During the unit shutdown on November 10, 1995, the resident inspector identified to the operators that they had failed to implement procedure and technical specification requirements to functionally test the rod sequence control system (RSCS) after the rod inhibit mode had automatically initiated. The plant shutdown integrated operating procedure, HC.OP-IO.ZZ-0004, requires both a system diagnostic test prior to further movement of control rods and the rod inhibit function be tested within one hour of RSCS automatic initiation. Neither of these requirements were met and the operators had continued inserting control rods. Operators subsequently stopped rod movement and successfully completed the required activities with power at about 24% of rated power. Since the RSCS is not required to be operable above 20% rated power, this did not result in a violation of the Limiting Condition for Operation. However, operator failure to implement the procedure requirements resulted in a violation of technical specification surveillance requirements. This matter resulted in a Licensee Event Report (LER), (50-354/95-034-00), dated December 15, 1995. The licensee provided an acceptable root cause analysis and appropriate corrective actions in the LER. As a result, this matter is considered to be the first example of a violation of technical specification required procedures and surveillance requirements.

Later during the shutdown period, on November 20, 1995, the resident inspector identified that operators were not implementing a technical specification requirement for refueling operations by ensuring that the reactor mode switch was locked in the Refuel or Shutdown position. This was a procedure requirement for integrated operating procedure, HC.OP-IO.ZZ-0005. While this step was initially met, there were no controls to ensure that the requirement was restored after activities that would change the mode switch position. In addition, it was further determined that operating procedure, HC.OP-DL.ZZ-0026, which controls periodic surveillance requirements such as verifying that the mode switch is locked, had been revised erroneously deleting the required surveillance acceptance criteria. Subsequent licensee review for similar problems identified two additional requirements that were in error in either procedure HC.OP-IO.ZZ-0005 or HC.OP-DL.ZZ-0026. These errors involved surveillance activities for the source range monitors (SRMs) and the containment suppression chamber level monitoring system. The licensee submitted an LER (50-354/95-035-00) documenting the root cause analysis and corrective actions for this matter. As a result, this issue is considered a second example of a violation of technical specification required procedure and surveillance requirements. Due to the LERs documenting the corrective actions for these violations, no response is required. **(VIO 50-354/95-19-01)**

2.5 Special Assessment of Refueling Outage Controls

Hope Creek personnel conducted station activities safely based on an independent review during the initial week of the sixth refueling outage. Areas reviewed by the inspectors included: overall outage management philosophy, outage schedule and shutdown risk assessment; including the use of the outage risk assessment and management (ORAM) system, operator monitoring of plant conditions, the control of work activities, the planning and implementation of outage modification, and the implementation of the corrective action systems. In general, the NRC concluded that sufficient management oversight and implementation of risk assessments were provided to ensure that shutdown activities were being accomplished safely.

Management Activities:

The outage management performed in a systematic manner with out any perceived schedule pressure. However, at the time of the inspection, licensee management had not completed the development of the outage schedule and duration, because of an ongoing effort to identify system and equipment problems for prioritization and correction during the outage. Management meetings focused on important emerging topics. However, outage meetings provided sufficient information on current plant status and planned work activities, but overall management expectations for these meetings had not been fully developed or enforced during this special review.

The Hope Creek management team including the general manager and outage director understood the importance of conducting the outage safely. It was clear that as problems developed the management team took the time necessary to conduct a detailed review and implement needed corrective actions. This included proper use of ORAM as a planning tool for identification of potential vulnerabilities resulting from overall station work. Management responded well to several issues including: higher than normal bay level and identification of a previously untested section of the safety related undervoltage logic systems.

As an overall plant improvement effort, licensee management supported a comprehensive and well documented review to identify and prioritize issues needing correction. This included the establishment of an Outage Review Committee (ORC) that provided management overview and assessment of equipment and system issues presented by the operation department or by system engineers. Operations department issues focused on equipment or system problems that caused operators difficulties (i.e., operator workarounds). System engineering issues focused on improvements to system and equipment operation, maintenance, or testability. From attendance and review of ORC meetings the inspectors determined that the different issues were being properly tracked and appropriate management interactions were taking place to ensure the identification of correctable issues. These discussions were frank and identified numerous issues that could, if corrected, potentially improve nuclear safety and plant overall performance.

The general manager's morning meetings provided a good opportunity for the senior plant staff to focus on daily issues and topics of interest. During the observed meetings, management from all station departments discussed issues of importance to them and the general manager provided good overall direction. Also discussed were the problems identified on Action Requests from the previous day. This discussion of Action Request issues were well conducted and provided good direction for initial followup and corrective actions.

The morning and afternoon outage meetings provided adequate discussions of completed and planned activities. Outage and operation management provided good discussion of upcoming evolution and work activities and the associated shutdown risks and restraints to scheduled activities. However, plant and outage management did not provide strong leadership to encourage standards of meeting conduct and outage schedule adherence. Plant and outage management expressed a desire to discuss each work activity not completed as planned, but station department supervisors did not adhere to this expectation. The mood of the meetings was very low key and managers did not always explore the reasons for delays in the completion of scheduled work.

Schedule:

The outage schedule properly used outage work windows to sequence the removal and return of safety-related systems in support of technical specification requirements and shutdown risk minimization. Prior to beginning the outage, licensee management decided not to conduct safety-related work activities until: reactor Operating Condition 5 (Refuel) was entered by removing the reactor head and subsequent establishment of refueling conditions. Prior to these new management expectations, the schedule initially planned outage system work windows to begin when the reactor entered Operating Condition 4 (Cold Shutdown). This change provided an additional safety margin and was the least intrusive scheme in that it left the individual, previously approved windows virtually unchanged.

The inspectors found that outage activities may have been unnecessarily complicated by a licensee decision that a mode change could not be made from Operating Condition 4 to 5 without ensuring the operability of all systems and instrumentation necessary to support moving reactor fuel. The inspector reviewed the technical specifications and the associated basis determining that this was an unnecessary yet conservative limitation. The inspector assessed that the Hope Creek technical specification mode change restraint only applied to mode changes conducted as part of a reactor startup.

Outage Risk Assessment and Management System:

The inspectors found licensee management and operators aware of shutdown risk considerations during planning of shutdown activities. Outage management procedure NC.NA-AP.ZZ-0055(Q), section 5.3.1 General Scheduling Guidelines, provided a comprehensive list of outage schedule preparation considerations. The preparation of the outage schedule includes an assessment which evaluates outage activities against the following shutdown safety issues: decay heat removal capability, outage inventory control, electric power availability/reliability, reactivity control, containment integrity primary/secondary, and correct manpower loading to safely perform the tasks.

Overall, plant personnel and station management used ORAM as an effective tool to assess, manage, and portray shutdown risk. Plant procedure HC.OM-AP.ZZ-0055(Q)-Rev.1 dated August 21, 1995 described the plant outage risk management and use of ORAM. The shift outage manager maintained the daily plant and equipment condition summary sheet and lists of higher risk evolutions for most systems critical during shutdown. Further the shift outage manager reviewed all emergent additions to the work schedule with respect to shutdown risk. The ORAM program was initially loaded with the established outage schedule. Daily updates were prepared and issued based on the new information provided in the daily summary sheet. Further, if unexpected conditions arose an updated output was developed. As an added measure of security, the on-site safety review group (SRG) performed an independent review of the initial refueling outage schedule and daily outputs from a risk management point of view.

The ORAM program contained the system interactions and redundancy logic necessary to determine the level of defense-in-depth status of reactivity control, shutdown cooling, reactor water inventory control, fuel pool cooling, electrical power, support systems, and secondary containment. The ORAM program generated a graphical printout using different colors to represent the defense in depth in these areas over a two month period.

- GREEN - Full DEFENSE-IN-DEPTH, more than adequate safety system redundancy exists
- YELLOW - Acceptable DEFENSE-IN-DEPTH, with minimal risk. Some of the plant systems may be slightly degraded.
- ORANGE - Minimal DEFENSE-IN-DEPTH, with risk potential. Requires that a contingency plan be developed and placed in effect.
- RED - Unacceptable risk. Condition not allowed, rescheduling of safety system work is required.

The inspectors noted that this was the first use of ORAM at Hope Creek and that the personnel were still learning the program. The inspectors noted the following weaknesses with the ORAM process at Hope Creek:

- there was no formal documentation maintained of the independent verification performed by SRG;
- the ORAM procedure did not define the higher risk evolutions listed in the summary sheet;
- the summary sheet also did not include plant system or equipment information for the Reactivity Control section of ORAM; and,
- the two month ORAM printout provided a comprehensive view of shutdown risk; however, it may be too broad to allow a specific assessment of small finite changes in the outage plan over a 24 hour period.

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 PS&G conducted these activities in accordance with approved procedures, technical specifications, and appropriate industrial codes and standards. 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

Outage Work Control and Safety Tagging

In the months preceding the refueling outage, Hope Creek personnel self-identified numerous safety tagging problems that were subsequently described and collectively characterized in NRC Inspection Report 50-354/95-17 as a Non-Cited Violation. During the outage, the inspectors revisited the safety tagging issue and determined that, while the number of tagging requests increased dramatically (to support the thousands of outage-related work activities), the overall number of identified tagging incidents actually decreased. The inspectors concluded that this fact was evidence that corrective actions stemming from the previous events had positively impacted implementation of the tagging program. Further, the inspectors noted that the significance of the issues that were identified were minimal. As an example, the inspectors identified one safety tag that, though not signed by the individual applying the tag, was attached to the correct component.

Just prior to the start of the outage, the Hope Creek work control center was modified to enhance work order and tagout processing and improve operations department oversight of maintenance and testing activities. Plant procedure NC.NA-AP.ZZ-0055 (Q)-Rev.1. defined the outage management program well. Individual responsibilities were clearly indicated. Review of selected activities showed that the planning was conducted well ahead and independently verified before the maintenance. Operations and maintenance personnel interacted adequately while releasing the work orders. A review of a sample of work order packages (CMs and CRs) indicated no significant problems.

While the inspectors observed generally good overall work control performance, there were some exceptions. For example, on December 18, 1995, the B emergency diesel generator inadvertently started while operators were implementing a tagout of the associated 4160 VAC Class 1E bus to support modification work to the under voltage relay logic. Procedural inadequacy and personnel error were labeled as the primary causes of this unexpected engineered safety feature actuation, which was appropriately reported to the NRC Operations Center in accordance with 10 CFR 50.72. Additionally, on December 18, 1995, poor maintenance technician turnover and weak procedural guidance resulted in an inadvertent over-thrusting of the high pressure coolant injection system steam admission valve following valve refurbishment. In this case, technicians failed to inform relieving workers that the valve's motor actuator limit switches were not yet engaged. Conduct of post-maintenance VOTES testing then resulted in over thrusting the valve disk into the backseat because the actuator control logic was disabled. Fortunately, in both cases, neither personnel injury nor equipment damage resulted. The inspectors reviewed both post-event root cause analyses and recommended corrective actions and judged them to be sufficiently self-critical and thorough.

In addition to the above described events, the inspectors noted two instances of outage work during which "live" 125-volt DC logic power was found unexpectedly in valve motor actuators, contrary to a Hope Creek Licensee Event Report (LER) 94-012-00 commitment. This LER stated that "...all valve operators that contain live circuits following tagging of the actuator and control power supply will be identified on the work order." In reviewing the noted two instances, the inspectors determined that an incomplete review of all affected Hope Creek valve motor actuators was the cause of one case, while the other was attributed to personnel error, in that the work planner was unfamiliar with the stated commitment. The inspectors considered both of these events to be evidence of weak implementation of corrective actions committed to in an earlier LER. Planned corrective actions after these licensee identified events appeared appropriate.

Maintenance/Surveillance Observations

The inspectors witnessed numerous maintenance and surveillance activities during the report period and concluded that, in general, these activities were effectively planned and implemented to assure continued safe and event free plant operations. Outage work was conservatively established in detailed schedules, and the management expectation of "taking the time to perform the job right the first time" was generally understood at both the technician and supervisory levels. Examples of this philosophy were evident during several jobs directly observed by the inspectors, including the replacement of the D service water traveling screen, the C service water pump replacement, the B/D vital bus under voltage relay rewiring, and the resolution of the D emergency diesel generator alarm function anomalies.

However, the inspectors observed one example of "critical path" safety related troubleshooting (C emergency diesel generator speed switch/tachometer generator failures) that was neither well planned nor implemented, and ultimately resulted in an additional burden being placed on the station because of technical specification required increased surveillance testing. Specifically, on December 6, 1995, a routine monthly diesel surveillance was halted (and the diesel declared inoperable) when the control room operator noticed that the "diesel stop" indication was still illuminated with the unit running. This equipment failure resulted in only one of two required diesels being available for emergency operation. Maintenance technicians, supported by system engineering personnel, promptly began troubleshooting efforts but did not effectively evaluate all the possible failure mechanisms prior to conducting retests, resulting in several diesel start attempts prior to identification of the actual failed component. Further, inattention to detail during the testing was evident in that on two occasions the test equipment used to monitor diesel control signals was either set up improperly or exceeded calibration due dates. In the end, two valid diesel start failures occurred requiring an increased testing frequency in accordance with technical specification table 4.8.1.1.2-1.

Mobile Crane Impact With 500 KV Line

On the evening of November 29, 1995, a mobile crane transiting the protected area access road in front of the Hope Creek station impacted one phase of the 500 KV lines leading from the main generator output transformers to the switchyard. At the time of the event, these lines were de-energized. The crane operator failed to lower the boom on the crane prior to passing beneath the lines, contrary to licensee procedures. In addition, the operator failed to self report the incident; the event only became known because it was witnessed by an individual leaving the Salem station who reported it the following day. The inspectors noted a good response from licensee management in that they took prompt action to "for cause" test the individual in accordance with the Fitness for Duty program (negative result) and subsequently terminated the individual for failure to follow established procedures and to self report the incident. The licensee also installed permanent gates across the access road on either side of the power lines to ensure future mobile crane operators would be cognizant of the potential safety hazard.

4.0 ENGINEERING

4.1 Inspection Findings

Emergency Diesel Generators

The inspectors noted that numerous condition reports were generated this report period documenting various discrepancies with the four emergency diesel generator units. While most of the issues were assessed as minor in nature with little to no impact on system operability, several problems arose with the B emergency diesel that warranted a more in-depth review. The inspectors concluded that, though the number of issues relating to the B diesel were many, engineering personnel investigation and resolution of the issues was generally good.

Specifically, on November 26, 1995, while control room operators were preparing to synchronize and load the B emergency diesel generator to complete an 18 month technical specification surveillance (24 hour run with "hot" restart), the output breaker automatically shut out of phase with the associated 4160 VAC vital bus (without any operator action); the breaker immediately tripped open on over-current. A Significant Event Review Team was assembled by Hope Creek management which determined that a failed Bailey Controls solid state logic module was at the root of the event. The inspectors assessed the team's findings and concluded that they performed a comprehensive analysis of the event and had good overall findings, including questioning the adequacy of the maintenance department's solid state logic module bench tester. In addition, engineering department recommended actions to inspect critical diesel generator mechanical components following the event was considered a positive indication of conservative decision making.

Subsequently, on December 11, 1995, while again attempting to complete the above noted 18 month technical specification surveillance, an equipment operator observed that generator output current indication for the A phase was zero with the diesel loaded. The unit, which had only been loaded for approximately 15 minutes prior to the discovery, was promptly unloaded and shut down. Follow up troubleshooting in the output breaker identified that the A phase movable contact arm did not fully close as a result of a missing pin that assures positive arm engagement with the hinge shaft. Engineering personnel determined that the pin fell out because a snap ring retainer was missing (never found). The entire breaker was replaced and the diesel surveillance was completed satisfactorily. The inspectors judged that engineering and maintenance personnel root cause assessment of this event was thorough, and noted that the recommended action to inspect a sampling of other vital 4160 VAC breakers was an appropriate initiative to verify that this issue was not generic.

Safety Auxiliaries Cooling System Operation Outside Design Basis

On December 4, 1995, Hope Creek operations personnel identified and reported to the NRC Operations Center per 10 CFR 50.72 that the safety auxiliaries cooling system (SACS), the safety related system that is credited with removing all heat from the plant following a design basis accident, was being operated in a condition outside its design basis. Specifically, the system was being operated at temperatures below 45°F, contrary to the Hope Creek Final Safety Analysis Report which states that SACS temperatures must remain above 65°F to preserve the structural integrity of system piping and supports. Operating status logs listed 32°F as the minimum allowable temperature for system operation. Further, the inspectors determined that the system had been operated in this manner frequently in the plant's nine year operating history. This matter was the subject of a detailed review by specialist inspectors during the inspection period. An assessment of licensee actions is included in Attachment 1 of this report.

Residual Heat Removal System Shutdown Cooling Common Suction Line

On December 8, 1995, Hope Creek operations department personnel determined that a failed snubber on the common residual heat removal system shutdown cooling suction line (which had been removed ten days prior) was not appropriately tracked, resulting in a failure to declare the shutdown cooling system (administratively) inoperable in a timely manner. Subsequent licensee inspection of the noted piping identified several hangers and structural supports that exhibited signs of significant damage. Further, this condition was a repeat observation that had been noted by the licensee during previous refueling outage inspections. Hope Creek management commissioned an outside contractor to perform a detailed root cause analysis of this issue so that appropriates measures could be established to prevent future piping damage and potential structural failure. This matter was also the subject of a detailed review by specialist inspectors during the inspection period. An assessment of licensee actions is included in Attachment 1 of this report.

Engineering Backlog

During this inspection period the backlog of engineering activities was reviewed to assess whether appropriate resources and priorities were being established to ensure that identified plant issues were evaluated and corrected, if necessary, in a timely manner. By the end of calendar year 1995 the total engineering backlog for Hope Creek stood at approximately 1300 activities. Of this, a total of about 185 activities were considered "overdue" by the licensee's priority system. Licensee management had committed to implement an Outage Review Committee to assess the need to implement corrective actions for identified plant problems prior to restart of the Hope Creek unit. The ORC and engineering organizations assessed the engineering backlog activities and determined that a total of 127 of these activities were required to be completed prior to restart. Based on inspector observation of ORC activities and review of Nuclear Business Unit engineering self assessments of backlog reduction efforts, the inspector determined that the engineering backlog was being appropriately monitored and effective use of priorities were maintaining the backlog at a reasonable level in order to ensure safe operations.

Modification Work-in-progress Observations

The inspector reviewed several modifications planned for the outage. One was a temporary, normal reconfiguration of the reactor vessel level instrumentation, which allowed reactor vessel water level indication with the head removed. The other was the modification to the A and C loops of RHR, which would allow the cross-tie of the C loop to the A heat exchanger. In both of these cases the inspectors found that the safety evaluations properly addressed reactor safety issues. The inspectors specifically monitored the installation of the reconfigured reactor vessel level instrument and discussed its use with the control room operators. The inspector found the installation using a temporary plant alteration proper and that operators understood the limitations of the instrumentation.

4.2 Followup of Prior Inspection Findings

<u>Unresolved Item 50-354/92-03-05</u> Inspection Report No. 50-354/92-03, dated June 10, 1992, states the following with regard to the ability of the filtration recirculation and ventilation system (FRVS) to reduce secondary containment pressure (reactor building drawdown time): "...the inspector also noted that the drawdown analysis did not take into account the possible two minute time delay (should the fan selected to AUTO-LEAD not start) when calculating drawdown times for various inleakage rates. This appeared to be inconsistent with the NRC Standard Review Plan which states that any time delay due to system design in actuating secondary containment depressurization and filtration systems should be considered." The licensee was asked to review this apparent inconsistency.

The inspector reviewed a July 1, 1993 letter to PSE&G from Bechtel which documents the completion of Revision 5 to PSE&G Calculation 11-66 (Q), "Post - LOCA Drawdown Analysis". The revised drawdown analysis included the following time delays: two minute delay in start of the standby FRVS fan following the initial fan start signal; 5 second delay for assumed instrument tolerances; and, 5 second delay for the fan to reach full speed. The analysis concluded that if the FRVS vent fans operate as designed, the system should be able to drawdown the Reactor Building to -.25" w.g. within the 375 seconds specified in the Technical Specifications if the building leakage is approximately 10%, per day, or less. The licensee indicated that the revised drawdown analysis will be used to perform a series of design basis accident dose calculations that reflect various potential reactor building inleakage rates. Based upon the above, URI 50-354/92-03-05 is closed.

Unresolved Item 50-354/92-80-08 Inspection Report 50-354/92-80 summarizes the results of the Electrical Distribution System Functional Inspection for Hope Creek. The report states the following: "...a lack of configuration control was noted when a walkdown revealed that a dc undervoltage relay was not shown on the one-line drawing. The relay was connected to a Class 1E bus, but was not hooked up to any alarm or actuation system. This relay was not maintained because custody was unclear. There was no setpoint provided."

The licensee's February 26, 1992 response to the inspection findings indicated that, if the relays were found to be necessary, increased maintenance will be instituted by the end of 1992. If removal of the relays is warranted, a design change will be initiated by June 1992. In a November 5, 1993 memorandum, the licensee indicated that the decision to remove the relays was made in June 1992. The licensee's document I.D. No. 4EC-3368, which concluded that the requirements of 10 CFR 50.59 do not apply to the removal of the relays, was reviewed by the inspector. The inspector reviewed Corrective Maintenance Work Orders 940509187, 940509209, 940509212, and 940509214. These work orders indicated that the relays in question were left, in place, with all leads removed. The removed leads were tied back and taped. Based upon the above, URI 50-354/92-80-08 is closed.

Inspector Follow Item 50-272 and 311/94-19-02, 50-354/94-19-05 In Hope Creek Inspection Report 50-354/94-19, dated October 14, 1994, it was noted that the licensee's procedure for implementing the requirements of 10 CFR 50.59, NC.NA-AP.ZZ-0059(Q), Revision 2, "10CFR50.59 Reviews and Safety Evaluations", NAP-59, should be revised to address the following: (1) The approver should be alerted that if a peer review is not required, the approver assumes the duties and responsibilities of the peer reviewer. (2) The definition of the Final Safety Analysis Report (FSAR) should be expanded to include those changes to the FSAR that have been implemented but not, as yet, submitted to the NRC per 10 CFR 50.71(e).

The inspector reviewed Revision 3 to NAP-59 dated November 19, 1994. Based upon the review, it was concluded that the revision to NAP-59 addressed assignment/responsibility for peer review by the approver and the expanded definition for the FSAR. Accordingly, it was concluded that the Revision 3 to NAP-59 is responsive to NRC concerns and the changes are acceptable. Based upon the above, 50-354/94-19-05 is closed.

Violation 50-354/93-06-03 Inspection Report 50-354/93-06 states that, "...the licensee supported a 'use-as-is' disposition for unqualified gauges in the gland seal portion of the high pressure coolant injection (HPCI) system. In the 10 CFR 50.59 review, the licensee states, 'The Pressure gauges are not described [in the UFSAR].' The PM determined that the statement is incorrect. The gauges are described in UFSAR Figure 6.3-2 as being within the "Q" boundary. Furthermore, in order to resolve this deficiency report, the licensee changed the normal position of the isolation valves for these gauges from open to closed. However, UFSAR Figure 6.3-2 clearly shows the isolation valves for these gauges as being normally open." The subject gauges are identified as 1FDPI-4881, 4882, 4885A, 4885B and 4885C.

The licensee's letter dated October 13, 1993 responded to the subject violation with the following remedial actions:(1) A 10 CFR 50.59 safety evaluation was performed, concerning configuration changes in UFSAR Figure 6.3-2, and concluded that no unreviewed safety question is involved. (2) An engineering change has been made to UFSAR Figure 6.3-2 consistent with the remainder of the UFSAR, and (3) lessons learned from this example, and management expectations, have been communicated to department system engineers. In confirming the licensee's corrective action, the inspector reviewed UFSAR Figure 6.3-2, Revision 6 dated October 22, 1994 and determined that (1) the root valves for the subject instruments were shown to be closed and (2) a note (8) had been added indicating that, "Root valves for non-Q impulse lines connected to ASME Class 2 or Class 3 Pipe on this P&ID shall remain in the open position only while being read by an operator. Otherwise, these valves shall remain in the closed position." In addition, the inspector reviewed the lesson plan used for 10 CFR 50.59 Training (L.P. No. 0905-300.20N-5059ZZ-00) and found that lessons learned from the subject violation are specifically covered in Section IV.C.1.b. Finally, the inspector reviewed the licensee's revised "10CFR50.59 Review and Safety Evaluation" concerning deficiency report HTE-92-230. The inspector agreed with the licensee's conclusion that use of the subject "non-Q" pressure gauges does not involve an unreviewed safety question provided that the associated root valves remain closed when HPCI is required to be operable. Based upon the above, violation 50-354/93-06-03 is closed.

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.

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 November 21, 1995, the inspectors observed the annual offsite response security drill involving the New Jersey State Police special weapons and tactics team and the licensee security force. The inspectors assessed that the drill training objectives were met and that appropriate access controls for both personnel and weapons were maintained throughout the duration of the drill.

Following the plant shutdown and subsequent layup of circulating water and the cooling tower discharge piping, the inspectors toured accessible portions of those systems to ensure adequate controls were in place to maintain protected area integrity. Following the tour and subsequent discussions with both plant management and security force management, the inspectors determined that appropriate access controls were being maintained.

On December 8, 1995, the inspectors witnessed an excellent overall response by the site security organization following an equipment failure which disabled a portion of the Hope Creek perimeter monitoring system. Security force personnel were immediately dispatched to monitor the affected areas, and remained throughout the short period of time needed to restore the system to normal status.

5.4 Housekeeping

The inspectors reviewed PSE&G's housekeeping conditions and cleanliness controls in accordance with nuclear department administrative procedures. During routine plant tours and following system restoration from maintenance activities, the inspectors observed generally good implementation of the station cleanliness program. Plant lighting conditions were very good and benefitted from the use of reflective paint on the floors. There was a notable lack of extraneous tools and equipment. Temporary scaffolding was found to be properly restrained and showed tags indicating that the licensee had inspected all scaffolding.

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.

The inspectors also reviewed a November 28, 1995 event in which a fire protection technician initiated an electrical transient that caused all the overhead annunciators in the Hope Creek control room to flash momentarily. Thorough engineering and site protection department follow up of the event determined that, when the technician cycled a fire protection panel common alarm reset switch, a large current spike was introduced on the associated electrical bus (which also supplies the overhead annunciator system), causing control room indications to respond erratically. Although no procedural violations or equipment problems were identified, the fire protection department management conducted a comprehensive post-review which resulted in timely and focused departmental training, enhancements to established procedures, and a re-emphasis of management expectations.

6.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION

The licensee initiated a number of improvements during this inspection period primarily focused on successful restart of Hope Creek and ensuring an appropriate level of safety during the refueling outage. Critical outage activities (based on risk to important systems like shutdown cooling capability and vital power supplies) were provided significant management attention, planning and coordination.

An Outage Completion Plan was developed and implemented on November 26, 1995, to describe the activities and controls to ensure: successful completion of refueling operations; identification and completion of physical and programmatic work necessary for safe, reliable post-refueling outage operations; and, a safe, uneventful unit restart.

The inspector observed portions of the licensee's review activities in support of the Outage Completion Plan. Outage Review Committee (ORC) meetings were attended that reviewed outstanding engineering activities, operator workarounds, temporary modifications and system walkdowns. The inspector assessed that the ORC process provided critical analysis of station readiness and resolution of material and process deficiencies. Clear priorities were established to support the reviews; these priorities were transmitted to the appropriate line organizations to ensure that backlogged work activities important to a successful outage and return to operations, were scheduled for completion during the outage. As an indicator of this process, originally only about 60 design change packages were to be implemented during this outage. As a result of new management expectations and priorities established by the ORC, in excess of 250 design change packages now have been approved.

In addition to the ORC process for backlogged work activities, system readiness reviews were conducted for about 30 plant systems, of which six were selected for detailed system walkdowns and design configuration assessment. The results of these walkdowns were discussed with engineering management and overall conclusions were that material conditions were generally good and no conditions were identified that resulted in a loss of system functionality. Another general conclusion was that a number of minor material deficiencies were identified during the system walkdowns that should have been previously identified by station personnel. However, the NRC assessment of this potential problem is that recent station performance in problem identification has much improved over the last four months. As an example, approximately 1800 condition reports were initiated in 1995, of which nearly one third were identified in the months of November and December. In contrast, prior to the new corrective action program being implemented in July 1995, problem identification rates averaged about 30 to 40 per month. While problem identification has improved recently, problem resolution timeliness has still been lagging. Resolution goals to close issues within 30 days are not yet being achieved; however, the NRC has observed that the backlog of overdue problem resolutions has received much management attention to improve timeliness of corrective action implementation.

The discussion of new condition reports and assignment of responsibilities during the general manager's morning meeting appeared an effective means of ensuring adequate interim corrective actions. As an example of a significant licensee identified problem, the inspectors reviewed an issue involving incomplete testing of the relays associated with the vital power system. Licensee management responded well following identification of an issue where several undervoltage relays had not been tested in the scope of prior logic system functional testing. One set of relays function to allow a fast transfer to the alternate offsite power source when the normal source voltage is degraded (degraded grid) and the other set allow the starting of the emergency diesel generators to re-energize the bus if the voltage is entirely lost (dead bus). Licensee management decided to allow testing of degraded and dead bus relays on the C and A busses with the busses energized. The inspector observed portions of the relay testing, finding the technicians and operators involved very knowledgeable. The C bus relays and the A dead bus relays were tested successfully. During the testing of the A bus degraded grid relays a technician inadvertently shorted a testing lead, causing a fast transfer to the alternate source of power. The planning for the testing had taken into account the possibility of a fast transfer and there were no safety significant results. Operators conducted restoration of this condition well. The inspectors found appropriate the licensee determination not to declare the EDGs inoperable, since technical specifications did not require EDG operability in operational conditions 4 or 5, if fuel handling or operations with the potential for lowering reactor vessel water level were not being conducted. Further, the individual loss of offsite power testing had previously proved the EDGs operable. This problem identified a weakness in the previous testing that could permit individual relays to be inoperable and yet prove the overall protection logic to be functionally acceptable.

The licensee also planned to conduct department self-assessments as part of the Outage Completion Plan. These self-assessments, as is the case for all outage completion plan activities, will be reviewed by the ORC for appropriate action prior to outage completion.

QA/NSR activities during the period were reviewed to ensure that findings were consistent with NRC assessments. No inconsistent findings were noted. The current "top 10" issues list of QA/NSR include: corrective action program implementation; procedure adherence; operability determinations; safety tagging; work control process; operator workarounds; shutdown risk assessment; operator performance; and, system engineering performance.

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.

Number	Description
LER 50-354/95-033-01	Technical Specification Surveillance Requirement Implementation Deficiencies.

As part of an ongoing review of technical specification surveillance requirements implementation as a corrective action for prior performance deficiencies identified earlier in 1995 (see LER 50-354/95-017), the licensee identified additional weaknesses in the surveillance test program. Among these was an inadequate logic system functional test of the vital bus undervoltage auxiliary relays and the degraded voltage relays. The inspectors observed portions of the troubleshooting and testing efforts as described in Section 2 of this report. The inspectors concluded that this additional self-identified surveillance discrepancy was another example of the violation described in NRC Inspection Report 50-354/95-11.

LERS 50-354/95-034-00 50-354/95-035-00	Technical specification violations during shutdown operations involving the rod sequence control system and the reactor mode switch.

These two LERs document the licensee's findings relative to two apparent violations of NRC requirements identified by the NRC inspectors. The licensee's review and corrective actions were considered to be comprehensive. In addition to the findings identified by the NRC, the licensee identified other similar weaknesses in the operating and surveillance test procedures that were also corrected. This matter is discussed further in Section 2 of this report and resulted in a violation as described in the enclosure to this report.

The LERs listed above are considered closed.

7.2 Open Items

The inspectors reviewed the following open items during this period. These items are tabulated below for cross reference purposes.

Number	Report Section	Status
354/92-03-05	4.4	Closed
354/92-80-08	4.4	Closed
354/93-06-03	4.4	Closed
354/94-19-05	4.4	Closed
354/94-24-01	Attachment 3	Open

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 Management Meetings

On December 11, 1995, Mr. Thomas Martin, Regional Administrator NRC Region I, Mr. Roy Zimmerman, NRR Associate Director for Projects, and Mr. William Dean, Assistant to the NRC Executive Director for Operations, toured the facility and met with station management.

8.3 Licensee Management Changes

Mr. Eric Salowitz was named director of nuclear business support, effective November 27, 1995. Mr. Salowitz was formerly the director procurement at Centerion Energy Corporation if Ohio prior to joining PSE&G.

Mr. David Powell was named manager of licensing and regulation, effective December 7, 1995.

U. S. NUCLEAR REGULATORY COMMISSION
REGION 1

DOCKET/REPORT NOS:	50-354/95-19
LICENSEE:	Public Service Electric and Gas Company
FACILITY:	Hope Creek Generating Station
LOCATED AT:	Hancock's Bridge, New Jersey
INSPECTION DATES:	December 11-15, 1995
INSPECTORS:	David Limroth, Senior Reactor Engineer Glenn Dentel, Reactor Engineer (Intern)

Insp Feeder Rept

A Lohmeier 1-22-96

Alfred Lohmeier, Sr. Reactor Engineer
Civil, Mechanical, and
Materials Engineering Branch
Division of Reactor Safety
Date

APPROVED BY: for Cheryl D. Beardslee 1/22/96

Michael C. Modes, Chief
Civil, Mechanical, and
Materials Engineering Branch
Division of Reactor Safety
Date

Areas Inspected: Review of the inservice inspection program implementation, including implementation and results of the 10-year long-term inspection plan, in-vessel visual inspection (IVVI), local leak-rate testing, erosion/corrosion pipe degradation evaluation, and inservice inspection quality assurance. Review of licensee evaluation of operation of the safety auxiliary cooling system (SACS) at heat exchanger outlet temperature below the 65 F design temperature indicated in the final safety analysis report (FSAR), and continued operation of the reactor heat removal (RHR) system without definitively determining the root cause of the repeated snubber failure.

DETAILS

1.0 SCOPE OF INSPECTION

The scope of the inspection covered a general review of the inservice inspection program implementation. Included in the review was implementation and results of the 10-year long-term inspection plan, in-vessel visual inspection, local leak-rate testing, erosion/corrosion pipe degradation evaluation, and inservice inspection quality assurance. Also reviewed during the inspection week was the corrective action taken as a result of operation of the safety auxiliary cooling system (SACS) at heat exchanger outlet temperatures below the 65°F design temperature published in the final safety analysis report (FSAR), and continued operation of the residual heat removal (RHR) system without definitively determining the root cause of repeated snubber failures.

2.0 HOPE CREEK LONG-TERM INSERVICE INSPECTION PROGRAM

Public Service Electric and Gas Company (PSE&G), the licensee, assumed responsibility in 1993 for the preparation, update, and maintenance of Hope Creek Generating Station's (HCGS's) ISI program and 10-year long-term inspection plan. Southwest Research Institute was originally contracted to perform those functions. They prepared the existing long-term plan that was submitted for approval to the NRC. The licensee had previously assumed responsibilities at the Salem site, and now has complete control of the ISI program at all three of its nuclear facilities.

PSE&G is currently updating and revising the 10-year long-term inspection plan. The revised long-term plan has not yet been submitted for NRC approval. The licensee also has updated the computer version for the surveillance scheduling system for the long-term plan.

2.1 Examination Plans and Schedules

The inspectors reviewed the 10-year long-term ISI plan of HCGS to determine that the inspections were conducted in compliance with ASME Code, Section XI. The applicable Code for HCGS is the 1983 Edition of this Code, including the summer 1983 addenda. The Code requires a minimum and maximum percent of inspection completed for an inspection period with 100% completion by the end of the 10-year inspection interval. HCGS is currently in the second outage (of three) in the third period of the first 10-year interval.

The inspectors noted that, in the HCGS ISI summary for the first interval, there were several categories that appeared to be in conflict with the Code requirement of Table IWB-2412-1. The licensee's ISI senior engineer responded with detailed information documenting the reasons for the apparent conflict. Several of inspections were allowed by the Code to be deferred to the end of the interval. Also, several categories were affected by an RHR cross-tie modification that added 46 new welds and supports to the long-term ISI plan. The inspectors concluded that HCGS could meet the Code requirements by the end of the first interval.

The inspectors reviewed the licensee's 90-day inservice inspection report for the fifth fuel cycle. HCGS noted two discrepant conditions in their IVVI during RFO 5. Adjusting screw tack welds on three jet pumps were found to be cracked, and numerous small cracks were detected on the steam dryer support ring. These two items will be discussed further as part of the IVVI section. All leakage and pressure tests were within their allowable limits. Erosion/corrosion tests revealed seven components below 70% wall thickness. These components were either repaired or replaced in accordance with Code requirements.

The inspectors' review of the long-term plan, inservice inspection report, and other supporting documents reflected a well managed program. The ISI engineer, who manages the program, demonstrated a complete understanding of the ISI program and showed an excellent sense of ownership of the long-term plan.

2.2 Inspection Results (RFO 6)

In the 1995 refueling outage (RFO 6), the licensee found one indication in the core spray system using magnetic particle testing. A 5/16" indication on the valve side in the base metal for the valve to pipe weld was discovered in the core spray system. The licensee issued an action request (AR) for review of this item. From the AR, a performance review and a work order was issued. The 5/16" linear flaw was greater than the allowable flaw size as specified in Table IWB-3514-4. Per the work order, the flaw was cosmetically worked with a flapper wheel. Subsequent NDE inspection detected a 5/32" indication that is within the allowable linear flaw size.

In the visual inspection of struts in Hope Creek, the licensee has discovered numerous indications of loose locknuts. Although the original inspection was limited to 300 to 400 struts, the licensee expanded this to all struts as a consequence of finding the abundance of loose locknuts. A root cause investigation is currently underway. The corrective action is also being determined. Minimum corrective action includes tightening the locknuts to the specified torque.

2.3 License Event Report 95-013

As reported in LER 95-013, the licensee missed a surveillance test required by plant Technical Specification 4.0.5. The licensee failed to pressure test piping associated with the turbine first stage pressure inputs to the reactor protection system. The origin of this omission was personnel error in converting items from boundary diagrams to the long-term plan at plant startup. The component is required to be tested every period in the interval. The component was pressure tested in the first period with a test unrelated to the ISI requirement. The omission was discovered during a self-assessment conducted in the support of the long-term inspection plan. Due to the first period inspection, the inspection was only overdue by two weeks. The licensee states that safety significance is low due to the fact that periodic inspection in that area by operation and maintenance personnel performing work would have detected any leakage.

The inspector interviewed the personnel involved in the discovery of this event. The inspectors concurred that personnel error at the initial conversion of the boundary diagrams to the long-term plan was the cause of the problem. Self-assessment of the licensee in discovering this error was considered a plant strength. The licensee took subsequent actions to improve the systems monitoring of the required surveillance intervals.

3.0 IN-VESSEL VISUAL INSPECTION

During the course of RFO 6 inspection, HCGS was performing visual examination of reactor pressure vessel internals. The examinations were conducted by a General Electric Company Level 3 examiner using remotely-controlled underwater video cameras, and the results were recorded on videotape. The components examined included jet pumps 11 through 20 riser braces, core spray spargers "A", "B", "C", and "D", core spray piping, shroud head/separator assembly, shroud head bolts, orificed fuel support casting, top guide assembly and wedges, jet pump restraining screws, and steam dryer support ring.

As a result of the IVVI, indications were found in the core spray bracket bolt tack weld at 195° (one of its two tack welds cracked), jet pump-retaining screw tack welds in jet pumps 1, 4, and 9, and three linear indications in the steam dryer support ring from 2 inches to 6 inches long.

The inspectors reviewed the video tapes showing the surfaces inspected on the core spray nozzles, and the tack welds on screws for jet pumps 1, 4, and 9. Two screws are threaded into each jet pump restrainer bracket, and each screw is locked into position by two tack welds.

The licensee examination revealed additional cracks in the tack welds of nuts in the pump hold down brackets of pumps 1, 4, and 9. For jet pump 9, the licensee plans to tack weld the screw using a proprietary procedure. The inspectors reviewed the procedure and questioned the contractor performing the task. The other jet pumps (19 and 20), with previous indications have not been examined at the time of the inspection, but will be completed after completion of the inspection.

The initial examination of the tack weld by the contractor on jet pump 4 was limited due to camera access limitation. Subsequent HCGS quality assurance surveillance identified that the Level 3 examiner had accepted a tack weld inspection having only limited view by the camera. With reexamination, albeit more difficult, additional cracks were found in the tack welds of jet pumps 4 and 9.

The tack weld cracks will be evaluated in accordance with vendor derived standards for acceptance or repair of the cracked welds in accordance with standards set for acceptance of cracks in the tack welds (GE SIL 574 states that, if one weld is found cracked, it may be evaluated, but if two welds are found cracked, a weld repair is required). Since two welds on jet pump 9 were found cracked, they will require repair. This repair is documented on Action Request 951202133.

The licensee demonstrated strengths in the evaluation of visual inspection results and implementation of repairs appropriate to vendor and HCGS standards of workmanship and safety.

4.0 LOCAL LEAK-RATE TESTING PROGRAM

The inspectors reviewed the licensee's program for leak-rate testing of Type B (electrical and mechanical penetration seals, mechanical expansion bellows, drywell airlock, etc.) and Type C (valves) isolation boundaries.

Through interviews and review of related records, the inspectors noted that the program being implemented under the direction of the responsible engineer provided excellent controls to assure that all components and penetrations are tested as scheduled. Each component or penetration within the program is assigned a unique recurring task identification that is used in conjunction with the maintenance management system to generate work orders for the accomplishment of the test procedure. In addition, the responsible engineer has implemented an independent program that is updated on an as-occurring basis, reflecting the results of each test and a current total leak rate based on those results.

The inspectors reviewed the two procedures that provide the instructions necessary to perform leakage measurements through Type B and C boundaries, procedures HC.RA-IS.ZZ-0009(Q) and HC.RA-IS.ZZ-0010(Q) respectively. These procedures were found to be extremely thorough and provided clear step-by-step instruction in the degree of detail necessary for the accomplishment of the tests. Quantitative acceptance criteria were included against which the success or failure of the test might be judged.

The inspectors reviewed several "Performance Review Descriptions," the documented review and acceptance or recommended rework, generated as the result of each component or penetration tested. These were found to be complete and clearly reflected the basis for acceptability when the administrative leak rate was exceeded. (The administrative leak rate is a function of the allowable total leak rate and the fraction of the total leakage path provided by a given component. The administrative leak rate is conservatively less than that determined through ASME XI calculations.) Corrective maintenance work orders for the repair of components determined to be unacceptable were reviewed and found to adequately describe the work required to restore the component to an acceptable condition. Post-corrective maintenance leak-rate test results were also examined to ascertain that the component was acceptable following maintenance.

The inspectors concluded that the leak-rate testing program was well managed and implemented.

5.0 EROSION/CORROSION DEGRADATION EVALUATION PROGRAM

The inspectors reviewed the PSE&G piping system erosion/corrosion program conducted at HCGS. This program monitors piping system wall thickness degradation trends due to erosion/corrosion of the inside wall of the piping. Ultrasonic testing (UT) is used to measure the pipe wall thickness at critical points in the piping system. The program is based on the use of a model of the piping system within computer software called Checmate/Checworks that identifies, for the piping system analyzed, those areas in the system having potential for erosion/corrosion based on flow and structural considerations.

Fourteen systems are being monitored at HCGS. Of these 14 systems, 8 have been modeled by Checmate/Checworks. These include: heater drain, seal steam, moisture separator drain, extraction steam, crossaround piping, reactor water cleanup, feedwater, and condensate piping systems. Those piping systems monitored, but not included in the computerized modeling system, include heater vent, RCIC drain line, HPCI drain line, radwaste off-gas, main steam drain, plant heating, and liquid radwaste.

On the basis of the RFO 6 inspection program, it was determined that two components should be replaced because of wall thinning. These are the two 2-inch diameter elbows and their downstream pipe located on the upstream side of valve V520 going to the "C" condenser from the HPSI drain pot. The total number of components included in the initial examination is 168.

The inspectors found the monitoring results to be well documented and easily retraceable for future comparisons used in predicting when the wall thickness will be reduced below acceptable values and require repair or replacement of the piping component. The inspectors reviewed samplings of data and data evaluation sheets and found them to be clear and comprehensive in the assessment of pipe deterioration due to erosion/corrosion.

6.0 INSERVICE INSPECTION QUALITY ASSURANCE

The Quality Assurance Section at Hope Creek is divided into individual functional groups. The licensee assigned a quality assurance (QA) engineer to be responsible for QA ISI, welding, pipe support, and IST. The inspectors reviewed the adequacy of QA for ISI from an interview with the QA engineer and a review of the ISI functional area notebook. In addition, the inspectors reviewed the last audit of ISI and the surveillance report on IVVI.

The QA engineer assigned to ISI was qualified as a Level 3 for Visual Testing inspection and had additional training in magnetic and penetrant testing. The engineer displayed a willingness to perform the research to enhance the quality assurance audits and surveillances. In the IVVI, the engineer examined several GE services information letters and reviewed NRC generic letters. The engineer also has developed a well thought out and extensive inservice inspection critical attributes listing. The inspectors considered the engineer's qualifications and preparations a program strength.

The inspectors reviewed the last audit performed on the ISI program and the surveillance report on IVVI. The audit and surveillance revealed an in-depth review of the program. Through excellent preparation and extensive knowledge of visual examinations, the engineer was able to pinpoint critical areas in the IVVI. This work resulted in a critical finding that the contractor had not fully examined the jet pump tack welds. The engineer wrote an action request, and the tack weld was reexamined and found to be cracked. This is just one example of the high performance level of the quality assurance reviews. The inspectors believe the quality assurance program oversight strengthens the HCGS ISI program.

7.0 SAFETY AUXILIARY COOLING SYSTEM PIPING LOW TEMPERATURE OPERATION

The safety auxiliary cooling system piping provides cooling water to the engineered safety features equipment, including the residual heat removal heat exchanger, diesel generator coolers, fuel pool heat exchangers, and various pump seals, room coolers and chillers. The SACS consists of two redundant loops, each loop consisting of two 50% capacity pumps and two 50% capacity heat exchangers. A bypass line between the SACS water inlet and outlet piping of the heat exchangers contains a thermal control valve that permits partial heat exchanger bypass flow and provides limited heat exchanger outlet temperature regulation. Each of the two loops is designed to provide the necessary flow to the system components during most operating conditions. The SACS heat exchangers are cooled by water from the station service water system (SSWS).

The design SSWS inlet temperatures to the SACS heat exchangers are 85°F (maximum) and 31°F (minimum). According to the FSAR, the design SACS outlet water temperature from the SACS heat exchangers is 95°F (maximum) and 65°F (minimum). The temperature range of the SACS outlet temperature from the heat exchangers used in the thermal expansion flexibility analysis for the majority of the SACS piping system is 70°F to 150°F. (The maximum temperature is derived from the line index for the Hope Creek Generating Station, Specification 108355-P-0501, Revision 34.)

In December 1985, during startup testing, it was recognized that SACS heat exchanger outlet temperatures were as low as 44°F with the heat exchanger bypass fully open. A startup deviation report (SDR) was initiated at that time, requesting the minimum temperature at which the SACS and components cooled by SACS could be operated. In response to that SDR, it was simply recommended that certain components, such as oil coolers and chillers, not be operated with inlet temperatures below 65°F. However, it was believed that operation with SACS water temperature of 48°F during testing should not cause any structural damage. Subsequently, a related SDR was submitted in early January 1986 that requested an evaluation and determination of whether systems temperatures as low as 37°F violated any temperature limitations on SACS components or had caused any structural or metallurgical damage. In response to the SDR, HCGS project engineering reported that review of operation with the SACS low temperature of 37°F indicated that "there will be no adverse impact to structure or metallurgy of all components using the above low temperature of 37°F."

On January 20, 1986, another SDR was initiated following a start-up test in which the system experienced a transient from a condition of two SACS pumps operating with their associated heat exchangers isolated and bypassed with an operating temperature of 74°F to the condition that would exist following a loss of off-site power and loss of coolant accident, i.e., four SSWS pumps providing cooling water to the SACS heat exchangers, four SACS pumps operating with full flow through their heat exchangers, bypass valves shut, and non safety-related heat loads isolated. SACS heat exchanger water outlet temperature was noted to have dropped to 44°F in 10 minutes following initiation of the transient. The SDR assessed the effect of this temperature on operability and minimum temperature for any SACS-related components and was found to be acceptable.

Again, in December 1990, an Action Request was issued to determine the impact of operating SACS at temperatures between 40 and 65°F and the attendant effect on SACS-supplied chillers and the potential for SACS piping condensation to damage electrical equipment below it. As a result, procedure HC.SE-PR.EG-0001(Q), SACS Annual Biofouling Monitoring, was modified to reflect a 40°F minimum heat exchanger outlet temperature.

Most recently, the licensee contracted with a recognized engineering consultant for an engineering evaluation of the SACS piping at low temperature operation. The preliminary report was noted to conclude that the reanalyses of the six sets of pipe stress calculations for a temperature range of 32°F to 150°F showed that the calculated stresses were acceptable at all points. In four of the six sets, all stresses in the piping were within the allowable stress. In two sets, the stresses exceeded the allowable stress by 0.2% and 0.6%, respectively. The licensee considered the slight overstresses to be insignificant.

During interviews with plant staff personnel, the inspectors were informed that operating the SACS with maximum heat exchanger bypass flow would not restore SACS heat exchanger outlet water temperature above the minimum design temperature of 65°F. Abnormal system configurations were considered, such as shutting the SSWS inlet valve to one heat exchanger, shutting the SACS inlet valve to the other heat exchanger that had SSWS flow, fully opening the heat exchanger bypass valve, and periodically manually initiating SACS flow through the heat exchanger with SSWS flow as SACS temperature increased. Should instrument air have been lost, the heat exchanger bypass valve would have failed to the shut position, and the resultant flow from two SACS pumps through one heat exchanger would have significantly exceeded design flow with probable damage to the heat exchanger resulting. Therefore, this abnormal mode of operation was not attempted.

Interviews with plant staff personnel indicated that the SACS may have been operated at temperatures below the design heat exchanger outlet temperature on as many as 40 occasions, this estimate being based on switching SACS trains monthly during the four winter months over the past 10 years, when SSWS temperature is near freezing.

The inspectors reviewed the FSAR and noted that the minimum design temperature listed for the SACS was 65°F and had not been revised to reflect changes in actual operating procedures. 10 CFR 50.71(e) requires that "Each person licensed to operate a nuclear power reactor pursuant to the provisions of 50.21 or 50.22 of this part shall update periodically, as provided in paragraphs (e)(3) and (4) of this section, the final safety analysis report (FSAR) ... The updated FSAR shall be revised to include the effects of: all changes made in the facility or procedures as described in the FSAR; all safety evaluations performed by the licensee either in support of requested license amendments or in support of conclusions that changes did not involve an unreviewed safety question ... "

Contrary to the foregoing, SACS, originally designed for a low operating temperature of 65°F, was repeatedly operated at temperatures less than the prescribed minimum reflected in the FSAR for almost a decade. Although this operation - at a temperature outside the prescribed bounds of the FSAR - was recognized and the effect of this operation was evaluated and found acceptable by HCGS engineering, the licensee failed to make the appropriate changes to the FSAR. The inspectors believe that the foregoing is an apparent violation of 10 CFR 50.71(e).

8.0 SNUBBER FUNCTIONAL TEST FAILURE

On November 27, 1995, in Refueling Outage 6 (RFO 6), Snubber 1-P-BC-049-042, failed its functional test. It was disassembled, and internal parts were found damaged. According to Hope Creek Technical Specification (TS) 3/4.7.5, "With one or more snubbers inoperable, within 72 hours replace or restore the inoperable snubber(s) to operable status and perform an engineering evaluation ... or declare the attached system inoperable and follow the appropriate action statement for that system." After the 72-hour limit was exceeded, TS 3.9.11.1 was entered for common shutdown cooling suction header being inoperative. The licensee reported this as a technical specification violation because shutdown cooling was required to be operable during this period, and actions for shutdown cooling being inoperable in TS 3.9.11.1 were not followed.

The licensee performed a walkdown of the system to assess the damage due to the overload condition. The licensee found the following:

(1) Snubber 1-P-BC-049-H027 - a clamp was found rotated around the pipe

(2) Snubber 1-P-BC-049-H017 - a cold setting was found at "0" indicator level

(3) Strut 1-P-BC-049-H023 - a bottom bushing was found dislodged 1/8" out of the paddle

(4) Strut 1-P-BC-049-H016 - a clamp was found rotated around the pipe

(5) Strut 1-P-BC-049-H005 - the top bushing was found cracked and dislodged place

On the basis of these observations, the licensee believed the most probable cause of the damage to the snubber is an overload condition due to excessive internal pipe forces.

The licensee performed a piping system stress analysis of the system considering design basis conditions, including seismic loadings. The analysis evaluated the system stresses with the original failed snubber missing and with the as-found condition of the two snubbers and three struts. Based on the analysis, the licensee concluded that all pipe stresses are below the design stress allowables, local stresses at welded attachments are acceptable, and valve accelerations are less than the allowable limits. A root cause investigation is ongoing to determine the apparent cause of the transient and the appropriate corrective actions that need to be taken.

The licensee noted that previous failures of Snubber 1-P-BC-049-042 occurred at HCGS. In RFO 4, (October 1992) HCGS discovered that the snubber off the common suction on the RHR B loop had broken clips. In RFO 5 (March 1994), the same snubber was found to be bottomed out. On the basis of this finding, the licensee believed the cause of failure to be dynamic loadings within the pipe similar to water hammer. A corrective action plan was proposed to revise plant operating procedures to prepare the RHR system for service. The failure of the same snubber in RFO 6 indicates that the corrective action was either inadequate or not implemented. Engineering could not ascertain to the inspectors that the corrective action suggested for RFO 5 was implemented.

The inspectors found that 10 CFR 50, Appendix B, Criteria XVI, states that "Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition."

Contrary to the foregoing, it was found that the licensee experienced a series of snubber failures over a period of three cycles as a result of failing to take appropriate corrective action to ameliorate the high forces on the RHR piping system that damaged the piping support system. This is believed to be in violation of 10 CFR 50, Appendix B, Criteria XVI, Corrective Action.

9.0 MANAGEMENT OVERSIGHT

The inspectors observation of the inservice inspection activity revealed instances of weakness in management oversight of the corrective action process over many years. This was shown in the cases of the two apparent violations discussed in Sections 7.0 and 8.0 of this report, where management oversight could have directed the appropriate documentation and corrective action follow up to assure that the problems were resolved.

10.0 MANAGEMENT MEETINGS

The inspectors met with members of the HCGS engineering and licensing staff at the entrance meeting on December 11, 1995, to outline the scope of the inspection. Further information clarifying details of the inspection findings were reviewed by the inspectors subsequent to the inspection exit date and issue date of this inspection report. The inspectors met with members of the HCGS engineering and licensing staff at the exit meeting on December 15, 1995, to discuss the findings of the inspectors during the inspection week. The licensee did not disagree with the findings.

11.0 PERSONS CONTACTED

Public Service Electric and Gas Company

B. Briggs, QA Engineer
* J. Defebo, Principal Engineer, Quality Assurance
G. Englert, Hope Creek
C. Fuhrmeister, Nuclear Mechanical Engineering Supervisor, Hope Creek
* L. Lake, ISI Supervisor
A. Kao, Engineering Mechanics Supervisor
S. Ketcham, BOP Systems Supervisor, Hope Creek
W. Kittle, LLRT Engineer
* D. LaMastra, Design Engineer, Hope Creek
N. Mistery, Design Engineer, Hope Creek
R. Montgomery, Erosion/Corrosion Program Engineer
* J. Nichols, Manager, Specialty Engineering
* T. Oliveri, Nondestructive Examination Supervisor, Inservice Inspection
M. Puher, ISI Engineer
* J. Priest, Licensing Engineer, Hope Creek
* M. Reddemann, General Manager, Hope Creek Operations
S. Roch, Senior Project Engineer, Civil/Structural Programs
W. Sheetz, Inspection/Test Specialist
S. Sienkiewicz, Senior Staff Engineer, Inservice Inspection
W. Treston, Senior Supervisor, Inservice Inspection

Contractors

G. Crim
M. Heath

New Jersey Department of Environmental Protection

* A. Kapsalopoulou, Research Scientist, Bureau of Nuclear Engineering

* Denotes those present at the exit meeting.

U.S. NUCLEAR REGULATORY COMMISSION
REGION I

DOCKET NO./REPORT NO.: 50-354

LICENSEE: Public Service Electric and Gas Company
Hancock's Bridge, New Jersey 08038

FACILITY: Hope Creek Nuclear Generating Station

LOCATION: Hancock's Bridge, New Jersey

DATES: November 20-29, 1995

INSPECTOR: James D. Noggle 12/26/95
James D. Noggle, Sr. Radiation Specialist date
Radiation Safety Branch
Division of Reactor Safety

APPROVED: John R. White 1/4/96
John R. White, Chief date
Radiation Safety Branch
Division of Reactor Safety

<u>Areas Reviewed</u>: The inspection was an announced review of the radiation controls program implementation during refueling outage conditions. Areas reviewed included outage radiation controls staffing, contractor radiation protection (RP) technician training, external exposure control, internal exposure control, and exposure reduction initiatives.

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REPORT DETAILS FOR RADIATION CONTROLS OUTAGE INSPECTION NO. 50-354/95-19

1.0 INDIVIDUALS CONTACTED

1.1 Principal Licensee Employees

T. Cellmer, Radiation Protection Manager, Hope Creek
V. Ciarlante, Senior Radiation Protection Supervisor - ALARA, Hope Creek
R. Gary, Senior Radiation Protection Supervisor - Operations, Hope Creek
K. Maza, Chemistry/Radiation Protection/Radwaste Manager, Hope Creek
K. O'Hare, Senior Radiation Protection Supervisor - ALARA, Salem
M. Reddemann, General Manager - Hope Creek Operations
R. Ritzman, Licensing Engineer, Hope Creek

1.2 NRC Employees

S. Morris, Resident inspector, Hope Creek

The above individuals attended the inspection exit meeting on November 29, 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 radiation controls program at the Hope Creek Nuclear Generating Station during refueling outage conditions.

3.0 OUTAGE RADIATION PROTECTION (RP) STAFFING

The licensee expanded its RP organization to an additional 56 contractor RP technicians. The licensee established RP control points for the refuel floor and the drywell. All other areas of the plant were controlled from the 137-foot elevation access control point. The licensee assigned permanent RP staff supervisors to manage each of the RP control points on a 24-hour basis. During the inspection, the inspector observed good RP technician support in the major work areas with no personnel resource shortages noted.

4.0 OUTAGE RP STAFF QUALIFICATION AND TRAINING

The inspector reviewed the licensee's qualification and training program for selected contractor RP technicians with respect to criteria in ANSI 3.1-1981. All nineteen resumes reviewed met the experience requirements of their positions. The inspector verified records of RP technician screening examinations. All senior RP technician records reviewed indicated $\geq$ 80% test scores current within three years or certification by the National Registry of Radiation Protection Technologists. The inspector reviewed the site specific RP procedure examination and determined that the procedure examination could be enhanced to provide a better challenge to the RP technician candidates. Notwithstanding, all licensee required training and qualification requirements were met and were well documented with no documentation discrepancies noted. In addition, no RP technician training deficiencies were noted by the inspector through outage radiation safety work control coverage observations.

5.0 EXTERNAL EXPOSURE CONTROL

The inspector toured the major work areas of Hope Creek Station and observed the radiological control of work in progress during this inspection. Radiological work control was effectively divided into refueling floor and drywell control points with radiological controlled area (RCA) access provided through the 127-foot elevation access point. The balance of plant outage work was effectively controlled from the 137-foot elevation access point. The licensee provided very good RP interfaces for work crews prior to entering the RCA. The inspector observed effective discussions of work scenarios by work foremen and effective RP response in support of ongoing work at all RP control points. Effective communications and effective working relationships were evident.

Every individual entering the RCA wears an electronic dosimeter that is set to alarm at specific dose and dose rate values according to the specific radiation work permit (RWP) used. The drywell and refuel floor RP control points utilized remote closed circuit television monitoring of critical work areas. The drywell and refuel floor control points utilized two-way audio communications with one RP technician in the work areas. In addition, the licensee was testing two types of teledosimetry (electronic dosimeters that transmit the dose and dose rate indications to an RP control point monitoring location) to evaluate their usefulness in controlling external exposures for critical jobs. They were not used for constant job coverage during this outage. The inspector discussed with the licensee the advantages of the use of two-way audio communication with workers being monitored by video camera and/or teledosimetry to enable the RP technician monitoring the workers at the control point to instruct the worker and control exposure.

Two areas were observed that required additional attention by the licensee. Inside the drywell on the 102-foot elevation, the licensee identified an accessible area with dose rates in excess of 1 R/hr at 30 centimeters that was barricaded with a string of red flashing lights and applicable high radiation area postings. The inspector pointed out to the licensee that according to the regulations, flashing lights are acceptable to be used when locking an area is not practicable. In this instance, installation of a lockable barricade was a practical alternative. The licensee promptly shielded the exposure source to below 1 R/hr and removed the flashing light barricade, which effectively resolved the inspector's concern.

Another area that required additional exposure controls was with respect to the spent fuel pool. The inspector observed approximately 13 small braided steel cables tied off to the hand rail around the spent fuel pool that were labeled with radioactive material inventory tags. Several indicated dose rates greater than 1000 R/hr that were labeled as local power range monitors (LPRMs). The radioactive material inventory tags indicated that they were not to be removed from the spent fuel pool. No other radiological warning or control was provided. The licensee indicated that this weakness was previously self-identified on September 19, 1995, and that the licensee was actively pursuing a means for locking the cables to prevent lifting the LPRMs from their water-shielded location in the spent fuel pool. The licensee indicated that seismic qualification of the cable locks were under engineering evaluation at the time of the inspection. The licensee addressed the inspector's concern for appropriately posting the radiological hazard, by adding a sign to the hand rail stating, "Warning: Do Not Remove. Dangerous Radiation Levels May Result". The inspector determined that with consideration of the additional posting, the use of alarming electronic dosimetry, and with alarming area radiation monitors on the refuel floor that would alert personnel in the event of high radiation fields, that the underwater sources were safely controlled. Final resolution of locking these sources remains to be accomplished.

Radiation work permits (RWP) were reviewed and found to cover large ranges of radiological conditions and contained very limited job specific radiological control instructions. The RWPs provide for RP supervision review and approval for the application of radiation safety controls. Without specification of these control measures, the application of radiation controls is left to the discretion of individual RP technicians. Although this area was viewed as a potential weakness and could be enhanced, the inspector did not observe any specific weaknesses in actual radiation control practices observed by the inspector during this inspection.

6.0 INTERNAL EXPOSURE CONTROL

The inspector reviewed the results of air sample monitoring during the outage. At the time of the inspection, all air samples taken during the outage indicated very low results, i.e., below 0.5 derived air concentration (DAC). The inspector determined that, on average, 68 air samples were taken each day. Major work area placement of air samplers was observed to be appropriate and work area contamination levels were generally low. The licensee provided excellent contamination controls with a very good level of air sample monitoring. Due to the low activity of the air samples, no internal exposure tracking or internal exposures were recorded.

7.0 EXPOSURE REDUCTION

The inspector reviewed the results of the licensee's as low as is reasonably achievable (ALARA) program to determine the extent of the licensee's efforts to reduce exposures to personnel. The inspector reviewed the licensee's exposure tracking process and exposure reduction initiatives. The ALARA dose tracking report listed dose expenditures for each active RWP. Very good analysis of the dose expenditures was provided through the licensee's comparison of time, dose, and work status. Such evaluations permitted the licensee to effectively review jobs that had the potential to exceed planned collective exposure. The inspector determined that the licensee had an effective dose tracking process.

The inspector reviewed the licensee's outage preparation activities of exposure reduction initiatives. After the previous outage, RP lessons learned were collected and an action item list was established in preparation for this outage. Also prior to this outage, the licensee established several multi-discipline High Impact Teams that were organized to review the work scope for various areas of the plant or functional areas. Schedule and resource efficiencies were the focus of these teams, with some exposure reduction benefits also achieved. The ALARA initiatives for this outage included: reactor vessel nozzle flushing (a conventional practice used to remove radioactive crud from the vicinity of pipe weld examination work); and some shielding installations (principally in the drywell). The licensee also began plant modifications this outage to install a condensate system pre-filter. This plant chemistry modification is scheduled to be completed next outage. The condensate pre-filter is designed to remove feedwater metal impurities, e.g., iron, which may eventually result in a slight lowering of the station source term after several more years.

The inspector observed the in-field shielding efforts by the licensee and noted some attempt to shield portions of the drywell and some limited shielding in the rest of the station. General field radiation levels in the drywell were not significantly reduced by the licensee's initial shielding efforts. When this finding was communicated to the licensee, the RP organization reevaluated the as-found drywell dose rate fields, mobilized the appropriate resources, and installed additional shielding on the recirculation system piping in the drywell. Through the inspector's survey measurements, the general dose rates on the major piping and reactor vessel nozzle elevation of the drywell had been reduced from an average of 40 mrem/hr down to approximately 20 mrem/hr. The other drywell elevation dose rates remained the same. The licensee indicated that approximately 7 tons of lead shielding had been installed with the potential for saving 20 person-rem due to this shielding result.

In summary, the licensee has a very good exposure tracking process. The ALARA program resulted in relatively few exposure reduction initiatives and was not aggressive in its approach to reducing dose rates in the major dose contributing areas of the plant. The licensee's efforts in reducing general plant dose rate fields through the use of shielding were not initially effective. When identified, the licensee exhibited excellent responsiveness and achieved some good exposure reduction results in a short time period, which is indicative of a flexible and responsive organization. Continued efforts are warranted in actively pursuing a comprehensive station shielding program.

8.0 EXIT MEETING

The inspector met with licensee representatives (denoted in Section 1.0) on November 29, 1995. The inspector summarized the purpose, scope and findings of the inspection. The licensee acknowledged the inspection findings.

U. S. NUCLEAR REGULATORY COMMISSION
REGION I

DOCKET/REPORT NO: 50-354/95-19

LICENSEE: Public Service Electric & Gas Company
Newark, New Jersey

FACILITIES: Hope Creek and Salem Generating Stations
Hancocks Bridge, New Jersey

DATE: October 16, 1995

INSPECTOR: Leonard J. Privedy 1/17/96

Leonard Prividy, Sr. Reactor Engineer Date
Systems Engineering Branch
Division of Reactor Safety

APPROVED BY: Eugene M. Kelly 1/18/96

Eugene M. Kelly, Chief Date
Systems Engineering Branch
Division of Reactor Safety

SUMMARY: The licensee discussed the preliminary results of their reevaluation of the susceptibility of MOVs to pressure locking and thermal binding in a meeting with the NRC on October 16, 1995, in the Region I office. The engineering work incorporated into the licensee's evaluation was comprehensive. Details of the NRC review of the evaluation are attached which serves as an update to URI 50-354/94-24-01.

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DETAILS OF OCTOBER 16, 1995 MEETING REGARDING SUSCEPTIBILITY OF HOPE CREEK MOVS TO PRESSURE LOCKING AND THERMAL BINDING

1.0 EVALUATION OF PRESSURE LOCKING AND THERMAL BINDING OF GATE VALVES - (URI 50-354/94-24-01 - UPDATE)

The licensee recently reevaluated the susceptibility of Hope Creek MOVs to pressure locking and thermal binding (PL/TB) conditions, with contract assistance (MPR Associates evaluation dated September 27, 1995), while preparing their corrective actions and responses to NRC Generic Letter 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves." The licensee discussed the preliminary results of the PL/TB reevaluation during a meeting with the NRC in the Region I office on October 16, 1995.

Ten valves (core spray, LPCI, RCIC injection valves, two HPCI discharge valves, and the HPCI pump suction valve from the suppression pool), which were considered to be susceptible to PL/TB conditions, were evaluated. Best estimates of the required and available thrusts were calculated to determine the thrust margins. All valves exhibited acceptable thrust margin, with the core spray 5B injection valve (12-inch valve with 100 ft-lb motor) having the least margin (approximately 100,000 pounds thrust available versus 78,000 required or 28%). Although the licensee considered all valves to be operable, they subsequently initiated modifications to the ten valves to eliminate the PL/TB susceptibility. All valves, except the HPCI pump suction valve from the suppression pool (1BJHV-F042), will be modified during the current outage. Modification of 1BJHV-F042, which requires draining the suppression pool, will be completed during the next outage to coincide with the planned draining of the suppression pool.

The NRC reviewed the licensee's evaluation, including the calculations of thrust and torque with the various assumptions used to model conditions during a postulated PL/TB scenario. The engineering work incorporated into this evaluation evidenced several positive aspects:

- the evaluation, which the licensee defended well during the meeting, was comprehensive including proper treatment of uncertainties;

- the methodology used in the evaluation was unique and combined the best features of several existing industry approaches; and

- the assumptions for valve and stem friction coefficients were statistically well-based and backed by plant-specific data.

Also, the required thrust calculations were conservative in that the unwedging forces used to model the PL/TB condition were approximately 10% higher than actual thrusts measured during past MOV diagnostic testing. However, concerning the available thrust calculations, the licensee took credit for motor stall torque and inertial effects without substantiating (with sufficient test data) the basis for the quantitative allowances for these factors. Nevertheless, the NRC considered the licensee's operability assessment to be sound. The licensee provided reasonable assurance that the ten valves in question would properly function in a rapid depressurization transient.