U. S. NUCLEAR REGULATORY COMMISSION

REGION I

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Facility:	Hope Creek Nuclear Generating Station
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EXECUTIVE SUMMARY

Hope Creek Generating Station
NRC Inspection Report 50-354/97-07

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a six week period of resident inspection; in addition, it includes the results of announced inspections by three regional inspectors. Region-based inspections involved reviews of the Hope Creek Inservice Inspection (ISI) program, engineering support, and outage radiological controls.

Operations

Plant operators were frequently challenged by unexpected operational transients and material conditions caused both by equipment failures and human errors. However, immediate operator response to the events was typically good in that proper procedures were used, technical specification action statement requirements were followed, and three-way communications. (Section O4.1)

Station operators exhibited inconsistent performance with regard to attention-to-detail and human error. Weaknesses in this area were highlighted by a violation involving a failure to detect an inoperable station fire pump despite several opportunities for both operators and fire protection technicians to identify the issue in a timely manner. (Section O4.2)

Operators demonstrated proper implementation and knowledge of all applicable technical specification requirements during plant operation, shutdown, and refueling. Additionally, conservative decision making was evident during the course of various infrequently performed evolutions. (Section O4.3)

QA inspectors provided excellent oversight of plant operations, and routinely communicated observed deficiencies to shift management. (Section O7.1)

Poor operations department internal communication was evident when chemistry technicians did not inform plant operators of an out-of-specification standby liquid control tank concentration until two and one half hours after the discovery. (Section O8.2)

Maintenance

Technical specification required surveillance testing was conducted effectively. Governing procedures were of good quality and were properly followed. Pre-job briefings were thorough and demonstrated appropriate coordination for test completion. (Section M1.1)

Plant housekeeping and cleanliness declined during the period. (Section M2.1)

The ISI program was appropriately implemented in accordance with an approved plan and ASME Code Section XI. The ISI program manager exhibited a good understanding and ownership of the ISI program. (Section M2.2)

The snubber surveillance program was implemented in accordance with technical specifications by knowledgeable and technically competent individuals. The ongoing efforts to upgrade all plant snubbers was technically sound and was judged to be a good initiative to preclude problems previously experienced with plant snubbers. (Section M2.3)

Immediate response to understand and resolve an IGSCC-induced through wall leak on the "A" core spray pipe nozzle was good, however, questions remained regarding the adequacy of ultrasonic testing data analysis during the previous refueling outage. (Section M2.4)

In spite of proactive measures by PSE&G management to reinforce expectations regarding maintenance procedure adherence and attention-to-detail, several issues involving non-compliances and poor work quality were identified. Supervisory oversight of contract maintenance technicians was weak. (Section M4.1)

PSE&G personnel continued to document deficient conditions at the station with a low threshold for initiation. Plant management demonstrated good reviews of each new issue and required resolution during the refueling outage when appropriate. However, several issues were not documented in a timely manner to ensure timely review and corrective action. (Section M7.1)

Procedure changes incorporated following the most recent failure of the residual heat removal shutdown cooling suction line snubber, which modified the method used to place shutdown cooling in service, were effective and prevented recurrence. (Section M8.1)

Engineering

System engineering efforts in identifying and resolving emergent equipment failures were prompt and effective. The large scope of design change work scheduled for completion during the refueling outage demonstrated appropriate management focus on resolution of long standing equipment deficiencies. However, several examples of repeat equipment failures, extended system maintenance activities, and design change package deficiencies highlighted weakness in the quality of engineering support. An internal review of an extended reactor water cleanup pump outage was thorough and self-critical. (Section E2.1)

The program for designing and installing configuration changes to plant systems was acceptable. However, inadequate review of design documentation prior to implementation of a reactor core isolation cooling system modification resulted in a violation of 10 CFR 50.59 requirements in that no written safety evaluation was performed for the change as required. This failure was also an example of weak implementation of the peer review process. (Section E1.1)

The licensee generally took acceptable actions to address nonroutine plant events. When a root cause analysis was prepared, the analysis was thorough and detailed. Not all conclusions were conservative, however, as in the case of Struthers-Dunn relays in a mild environment. (Section E2.2)

For Struthers-Dunn relays in harsh environment, the failure to include five relays in the EQ list and to provide a reasonable technical justification for accepting a less than required relative humidity qualification resulted in a violation of 10 CFR 50.49. Also, the use of a calculated relay qualified life without reconciling the difference with actual data indicated an excessive reliance on a theoretical life extension method that is highly dependent on the correct selection of independent variables. (Section E2.2)

The delay in initiating a Struthers-Dunn relay failure analysis (24 relay replacements in three years) indicated a weakness in the program for monitoring the performance of safety-related components in a mild environment. (Section E2.2)

Less than acceptable judgement was used in the selection of the coil temperature rise of normally energized, safety-related Telemechanique and Agastat relays in a mild environment. Failure to verify the acceptability of the values used in life extension calculations and tests resulted in a violation of 10 CFR 50, Appendix B, Criterion 3. (Section E2.3)

The QA audit of Hope Creek engineering was good and provided an accurate assessment of the engineering programs. (Section E7.1)

Acceptable actions were taken to address several previously-identified issues. An inspection followup item was opened to evaluate resolution of medium voltage circuit breaker failures experienced during a recent event. (Section E8.1)

Plant Support

Generally good radiological control practices were observed during the period, which included both operational and shutdown conditions. Radiologically controlled area access controls were effective. (Section R1.1)

Refueling outage radiation work permits generally provided effective contamination control requirements, however, exposure reduction plans were not specified as job requirements. (Section R1.2)

PSE&G demonstrated good progress in developing and implementing an initial drywell shielding plan during the refueling outage, however, some weaknesses were noted with drywell postings and electronic dosimetry setpoints. (Section R1.2)

Some weaknesses in radiation protection controls were observed during the outage, including refueling tool contamination control and inside torus air sampling practices. (Section R1.2)

Radiation protection planning activities were not well integrated with outage work management planning and scheduling which resulted in less than effective ALARA performance. (Section R1.3)

The radiation protection continuing training program has been weak as evidenced by poor technician performance on a recent examination. (Section R5.1)

Generally good implementation of Hope Creek emergency plan requirements was observed during an unannounced drill. Appropriate procedures were used, good communications were established, and a proper turnover from the senior nuclear shift supervisor was completed. (Section P1.1)

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Report Details

I. Operations

O4 Operator Knowledge and Performance

O4.1 Event Response

a. Inspection Scope (71707)

The inspectors observed or reviewed operator actions during and following several unexpected transient events and conditions throughout the report period.

b. Observations and Findings

The inspectors noted that a relatively high number of unanticipated operational events occurred during the six week report period, which challenged the plant operators, including:

- "A" reactor recirculation pump trip due to failed transformer (9/2)
- turbine auxiliaries cooling system isolation due to failed fuse holder (9/4)
- offsite alert notification siren actuation due to poor maintenance controls (9/8)
- manual reactor scram due to failed main transformer cooling controls (9/10)
- condensate pump breaker failure due to faulty trip coil (9/10)
- reactor water cleanup system isolations due to failed flow transmitter (9/11)
- remote shutdown panel channel "takeover" during relay replacement (9/12)
- safety auxiliaries cooling system pump start due to operator error (9/14)
- service water pump start during remote shutdown panel surveillance (9/16)

Other unexpected issues also required prompt operator notifications and attention, including the discovery that the technical specification (TS) minimum boron concentration in the standby liquid control system storage tank was not maintained, and the identification of a through-wall leak in the "A" core spray loop piping nozzle to the reactor pressure vessel. Additionally, a failed refueling bridge main hoist cable emergency brake solenoid resulted in an emergency stop/deenergization of the bridge controls while moving spent fuel from the reactor core to the fuel storage pool.

The inspectors judged the causal factors of the noted events were an even mix of both human performance and material condition issues. Human error induced events typically involved failures to "self-check" or to understand system design and operation. Other events primarily resulted from random equipment failures. Several of the noted events are described in further detail in later sections of this report.

In general, immediate operator response to the events was good; governing abnormal procedures were used, communications were clear and accurate, and conservative decision making was evident. When required, events were properly reported to the NRC in accordance with 10 CFR 50.72 and 50.73. For example, on

September 2, 1997, the "A" reactor recirculation pump tripped causing a rapid power reduction to 40%. The inspectors witnessed operator response to this event and observed good follow up activities. Appropriate control rod insertions were made to ensure that the reactor power/flow ratio was maintained outside to the "instability" region, TS action statements were properly implemented for single recirculation loop operation, and balance of plant equipment was appropriately aligned to support the reduced power level. This event was caused by a failed transformer in the recirculation pump motor generator field excitation circuit.

On September 10, operators received a main output step-up transformer trouble alarm in the control room and promptly dispatched equipment operators (EO) to investigate. Upon arrival, the EO's reported that the transformer cooling fans were not running, there was an acrid smell, and there were unusual noises. Operators acted conservatively by quickly reducing reactor power using recirculation flow and manually scramming the plant. The inspectors observed proper use of the emergency operating procedures, good three-way communications, and detailed log keeping. The main output transformer problem was later attributed to a failed relay in a cooling system control circuit. (See also section O8.3)

On September 19, while in operating condition 5 with fuel in the reactor vessel, EOs identified leakage in the drywell which was promptly traced to a through-wall leak from the "A" core spray reactor vessel nozzle. The inspectors independently validated the leak source location. Operators properly declared all affected plant systems inoperable, including "A" core spray, high pressure coolant injection, and standby liquid control, the latter two systems which use the core spray penetration as their vessel injection point. Because the "B" and "D" channels were inoperable at the time of the discovery for scheduled outage work, the TS specifying the minimum operable trains of emergency core cooling could not be satisfied. Again, operators promptly recognized this condition and took appropriate actions. A timely and accurate non-emergency report was made to the NRC in accordance with 10 CFR 50.72. (See also section M2.4)

c. Conclusions

Plant operators were frequently challenged by unexpected operational transients and material conditions caused both by equipment failures and human errors. However, immediate operator response to the events was typically good in that proper procedures were used, technical specification action statement requirements were followed, three-way communications were employed, and conservative decisions were made.

O4.2 Attention-to-Detail and Human Performance

a. Inspection Scope (71707)

The inspectors evaluated several events during the period with focus on individual attention-to-detail and human error. Interviews, observations, and log reviews were conducted while forming this assessment.

b. Observations and Findings

The inspectors observed inconsistent performance at all levels of the operations department with respect to attention-to-detail and human error. Several examples of quality operations department findings were noted which resulted from good questioning, awareness, and research into current plant conditions. For example, several "near-miss" tagging events were avoided by alert operators assigned to remove blocking tags from equipment which was declared ready for restoration by maintenance personnel. Also, during core alterations, refuel bridge operators identified a double blade guide in the fuel storage pool that was improperly configured. Lastly, a senior operator determined that 18-month relay testing on a 4160V vital bus was overdue and was not properly scheduled before expiration of the TS-allowed grace period.

However, the inspectors also noted several examples of poor operator performance. Improper tracking of surveillance activities for two trains of the filtration, recirculation, and ventilation system nearly resulted in unplanned inoperability of the system. A spent fuel pool cooling pump tripped after an operator failed to adjust an automatic flow control setting before restoring a filter demineralizer valve to service. The "D" station service water pump started unexpectedly during a surveillance activity when a remote shutdown panel "emergency takeover" logic transfer switch was returned to its normal position because the pump was left in automatic control.

On September 15, 1997, the operations shift supervisor determined that the electric motor driven fire pump at Hope Creek had been inoperable for approximately 34 hours, likely the result of a bus swap which caused the motor supply breaker to open. Though a fire protection system trouble alarm was generated and acknowledged in the control room on September 14, no actions were taken to determine the cause of the alarm, and fire protection technicians were not notified of the condition. Additionally, fire technicians missed two opportunities to identify the inoperable pump during routine operator rounds. The inspectors judged that this event highlighted weaknesses in degraded condition problem identification; specifically attention-to-detail, questioning attitude, and understanding fire suppression system status. Because this issue resulted in an unknown degradation of the fire suppression system for an extended period, and because of the number of missed opportunities to identify and correct the issue, the inspectors determined that it was a violation of 10 CFR 50 Appendix B, Criterion XVI in that the fire suppression system degradation was not promptly identified and corrected. **(VIO 50-354/97-07-01)**

c. Conclusions

Station operators exhibited inconsistent performance with regard to attention-to-detail and human error. Weaknesses in this area were highlighted by a violation involving a failure to detect an inoperable station fire pump despite several opportunities for both operators and fire protection technicians to identify the issue in a timely manner.

O4.3 Technical Specification Compliance and Operator Decision Making

a. Inspection Scope (71707)

Several plant operational condition changes occurred during the report period which required a thorough review and understanding of TS requirements to ensure that compliance was maintained. The inspectors focused on operator performance during the changing conditions to ensure that all regulatory requirements were satisfied.

b. Observations and Findings

Several plant operational condition changes, both planned and unplanned, occurred during the report period, including:

- single reactor recirculation loop operation and recovery
- reactor scram from operating condition 1 to 3
- reactor plant cooldown to operating condition 4/5
- reactor vessel disassembly and core alterations
- operations with potential to drain the vessel (control rod drive replacements)

In every case, the inspectors observed that applicable TS requirements were satisfied. Additionally, "tracking" action statements were logged to ensure that inoperable equipment needed for an operating condition not currently applicable were known before mode changes. Surveillance requirements for infrequently performed evolutions were properly conducted at the correct frequencies. Appropriate retests were performed following unexpected failures of the refueling bridge.

The inspectors witnessed generally conservative plant operations and decision making. For example, refuel bridge operators did not hesitate to delay core alterations when reactor cavity lighting or water clarity degraded. Fuel handling was generally restricted to single dimension movements to enhance control of the evolution. Lessons learned from previous loss of shutdown cooling events at the station were reviewed during pre-evolutions briefings to ensure that reliable cooling system operation was maintained. A detailed engineering analysis and operability determination were performed and reviewed by the station operations review committee to justify the acceptability of "flooding up" the reactor cavity with the degraded core spray nozzle.

c. Conclusions

Operators demonstrated proper implementation and knowledge of all applicable technical specification requirements during plant operation, shutdown, and refueling. Additionally, conservative decision making was evident during the course of various infrequently performed evolutions.

O7 Quality Assurance in Operations

O7.1 Quality Assurance Oversight of Operations

The inspectors observed nearly continuous quality assurance (QA) department presence in the Hope Creek control room just prior to and during the refueling outage. QA inspectors provided excellent oversight of plant operations, and routinely communicated observed deficiencies to shift management. Daily QA observation reports were completed which documented findings. The inspectors reviewed three week sample of QA observation reports and judged them to be thorough and insightful. Several action requests were generated as a direct result of QA questioning and assessment. The inspectors concluded that the frequent QA oversight in the control room was a good initiative which enhanced safe plant operation.

O8 Miscellaneous Operations Issue

O8.1 (Closed) DEV 50-354/96-11-01: failure to revise TS bases as committed in a PSE&G license amendment for specific conditions that must be satisfied to justify extended allowed outage times for the "C" and "D" emergency diesel generators. The inspectors reviewed PSE&G's March 21, 1997 letter which acknowledged the deficiency, and judged the stated corrective actions to be reasonable. Actions included submitting revised TS bases for NRC approval (approved in TS Amendment 101), enhancing the licensing department process for tracking commitments, and verifying implementation of previous commitments. The inspectors observed that these actions were completed in a timely manner.

O8.2 (Closed) LER 50-354/97-021: standby liquid control (SLC) system tank concentration below technical specification limits. This issue was self-identified during routine monthly tank sampling. The sodium pentaborate concentration in the tank was restored to acceptable levels within the TS action statement allowed outage time. PSE&G performed a detailed root cause evaluation following this event and concluded that the tank concentration was diluted by both the manner in which quarterly SLC pump inservice testing was conducted as well as leaking demineralized water supply valves connected to the system. The inspectors verified that PSE&G implemented the LER-stated corrective actions which included increased frequency tank sampling and inservice test procedure enhancements.

During initial follow up to this event, the inspectors noted poor internal communications in that chemistry technicians did not inform plant operators of the out-of-specification tank concentration until two and one half hours after discovery. This delayed operator awareness of the need for a four-hour 10 CFR 50.72 report and entry into an eight hour allowed outage time for SLC TS action statement. Boron concentration was properly restored before expiration of the allowed outage time.

O8.3 (Closed) LER 50-354/97-022: engineered safety feature actuation - unplanned manual scram following a relay malfunction in the "A" phase main generator step-up transformer. This event was described in section O4.1 of this report. The inspectors verified that the faulty relay was replaced and that the transformer was thoroughly inspected for damage following the event. No new issues were revealed by this LER.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Technical Specification Surveillance Testing Observations

a. Inspection Scope (61726, 71707)

The inspectors observed the conduct of several TS required surveillance tests during the report period, including:

- "B" emergency diesel generator 24-hour run with hot restart
- torus-to-drywell vacuum decay test
- high pressure coolant injection (HPCI) system inservice test
- rod block monitor channel calibration for single recirculation loop operation
- reactor mode switch functional test
- reactor core alteration surveillances (one-rod-out interlock test, etc.)

Implementing procedures and FSAR system descriptions were reviewed in forming this assessment.

b. Observations and Findings

In general, the inspectors observed effective inter-departmental coordination and communication during surveillance testing. Pre-jobs briefings, especially for the torus-to-drywell vacuum decay test, were thorough and followed a scripted format to ensure all contingencies were addressed. The quality of the various implementing procedures was good in that all TS acceptance criteria were listed and necessary plant condition prerequisites were established. Operators and technicians demonstrated proficiency with the governing procedures.

Appropriately conservative decision making was noted with respect to the reactor mode switch surveillance. Specifically, a computer-generated alarm indication associated with a reactor protection system channel failed to change state during the test, which the procedure listed as one of the acceptance criteria. However, all other indications were as expected and the noted alarm point was not required per TS. In spite of the belief that the mode switch was in fact demonstrated to be operable, the shift supervisor declared the switch inoperable (and implemented appropriate actions) until the computer point discrepancy was resolved.

Good planning and coordination were noted prior to the HPCI inservice test, but test completion was hampered by poor communications between control room and field operators. Specifically, because of background noise in the HPCI room and poor portable radio equipment performance, delays in satisfactory test completion were experienced which required a system trip when suppression pool temperature reached its TS maximum allowable value.

c. Conclusions

Technical specification required surveillance testing was usually conducted effectively. Governing procedures were of good quality and were properly followed. Pre-job briefings were thorough and demonstrated appropriate coordination for test completion.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Station Housekeeping

The inspectors conducted numerous tours of the Hope Creek facility during the report period and observed generally adequate plant housekeeping and cleanliness. Detailed walkdowns in the torus, the drywell, and the main steam tunnel indicated acceptable material conditions in those areas. However, the inspectors identified deficiencies as well. Specifically, several unsecured ladders were discovered throughout the plant, as well as 55 gallon drums, tools boxes, and test carts. All of these issues were resolved after station supervision was notified. Additionally, several self-contained breathing apparatus used by fire protection personnel were observed lying on the floor near a 7 KV motor control center two days after an event involving a failed condensate pump circuit breaker. In part because of the increased number of station work activities due to the unit outage, the inspectors concluded that the state of housekeeping and cleanliness had declined during the period.

M2.2 Inservice Inspection

a. Inspection Scope (73753)

This inspection was conducted to determine whether the inservice inspection (ISI) of Class 1, 2, and 3 pressure retaining components was being performed in accordance with technical specifications (TS), and Section XI of the American Society of Mechanical Engineers (ASME) Code.

b. Observations and Findings

Hope Creek Generating Station (HCGS) TS 4.0.5 prescribes the surveillance requirements for ISI and testing of ASME Code Class 1, 2, and 3 components as required by 10 CFR 50.55a and ASME Code Section XI. HCGS was committed to ASME Code Section XI, 1983 edition, through Summer 1983 addenda, and to inspection program B of subsection IWA-2400, Inspection Intervals. The inspection program required that the first inspection interval be completed ten years following initial unit commercial operation. This inspection was conducted during the third and final refueling outage in the third period of the first ten-year interval.

The ISI Program requirements for HCGS were contained in a document titled, Long Term Plan, First 10 yr. Interval, Revision 0, dated July 1, 1987, developed by SouthWest Research Institute. Plant procedure NC.NA-AP.ZZ.0027(Q) - Rev. 2, Inservice Inspection Program, contained the requirements and responsibilities for the control and implementation of the ISI Program. The procedure clearly delineated the responsibility for the program implementation and established the contents of the ISI long term plan. The procedure provided a broad scope for program implementation and specified the various other procedures that contained the detailed information on how to implement the various processes. It prescribed the processes for addressing program submittal to the NRC, establishing frequency of examinations and test activities, conducting augmented examinations, reporting requirements, controlling work and maintaining records.

Review of procedures (73052)

The inspector reviewed the following procedures to ascertain whether they were in compliance with TS, ASME Code, and Updated Final Safety Analysis Report (UFSAR) commitments:

- NC.NA-AP.ZZ-0027(Q) - Rev. 2, Inservice Inspection Program.

  This procedure identified the requirements for the control and implementation of the ISI program.

- SH.RA-AP.ZZ-0101(Q) - Rev. 7, Control and Coordination of NDE Activities.

  This procedure contained the requirements for the control and coordination of nondestructive examinations (NDE) of mechanical components and piping at Hope Creek.

- HC.SS-IS.ZZ-0006(Q) - Rev. 0, Visual VT-2 Examination of Nuclear Class 1 Systems.

  This procedure provided general guidance on performing VT-2 of Class 1 systems during system leakage tests.

- HC.RA-IS.ZZ-0007(Q) - Rev. 2, Visual VT-2 Examination of Nuclear Class 2 and 3 Systems.

  This procedure provided the instructions necessary to accomplish VT-2 examination of Nuclear Class 2 and 3 systems during system inservice or functional tests.

The procedures implemented ASME requirements and were up to date for all currently approved code relief requests. By Safety Evaluation Report (SER) dated March 17, 1995, the NRC approved Hope Creek's request to use the provisions of Code Case N-498-1, "Alternative Rules for 10-year System Hydrostatic Testing for Class 1,2,and 3 Systems." This allowed the licensee to conduct a system pressure/leak test instead of a hydrostatic test at the end of the outage. Based on this, the licensee's use of the above referenced leak test procedures would be appropriate following the outage. However, the procedure for conducting VT-2 examination of class 2 and 3 systems would have to be revised when relief request dated July 15, 1997 is approved. This request asked for relief from the required 4-hour pressure hold time for insulated systems during system pressure tests. The licensee was aware of this and indicated that upon receiving the NRC approval of the request, the necessary changes would be made to the procedure.

<u>Observation of Non-Destructive Examination (NDE) Activities</u>

The inspector observed ongoing NDE activities. During each observation, activities were performed by qualified individuals using approved procedures. Portions of the following activities were observed:

- Liquid Penetrant Test (PT) of core spray pump plate to pipe weld, CP-206-CSPW4.

  This surface examination was conducted with an approved work order and in accordance with GE Procedure, PT-HPK-100V1, Rev. 0, Procedure for Liquid Penetrant Examination. The Authorized Nuclear Inspector (ANI) demonstration/process qualification for the process was accomplished prior to its use in the field as required. The technicians showed good questioning attitude when, as a result of minor indications observed, they opted to re-perform the examination.

- Ultrasonic Test (UT) of welds on the reactor water cleanup pipe (lines 1-BG-6DBA-001 and 1-BG-6DBC-002).

  This volumetric examination was conducted with an approved work order. Prior to conducting the UT in the field, the technicians completed the block calibration of the instruments as required.

The inspector noted no discrepancies with the portions of field activities observed.

Most field activities were conducted by level II technicians with all data subject to review and approval by level III examiner. The inspector reviewed the qualifications of some of the NDE technicians to ascertain whether NDE activities were being conducted by qualified individuals in accordance with the ASME code. There were four qualified NDE Level III examiners at Hope Creek. They were supported by NDE level III contractors (General Electric) during the refueling outage. The inspector reviewed the NDE certification for the four HCGS level III examiners. The certifications were current and reflected that the individuals were trained and qualified to perform level III NDE activities.

c. Conclusions

The ISI Program was being implemented with an approved plan and in accordance with ASME Code Section XI. Code cases used had been approved for use as part of the plan and reliefs from code requirements that were used had been approved by the NRC. The ISI engineer who manages the program showed a good understanding and ownership of the ISI program. Procedures were implemented properly by knowledgeable and technically competent individuals.

M2.3 Snubber Surveillance Program

a. Inspection Scope (50090, 61726)

The inspector reviewed the implementation of the snubber surveillance program to ascertain whether it was being implemented in accordance with the technical specifications.

b. Observations and Findings

TS 4.7.5 prescribes the surveillance requirements to demonstrate that snubbers are operable. The inspector observed portions of the program implementation with focus on the ongoing snubber replacement project.

As a corrective action to previous industry and plant specific problems (such as the repeated failures of the common RHR shutdown cooling suction line snubbers), the licensee was in the process of replacing all "PSA" and "E-Systems" brand snubbers (approximately 640) with "Lisega" brand snubbers.

The inspector reviewed a portion of the design package (4EO-3507, Rev. 0) that was being used for the snubber replacement effort. The package was thorough and properly addressed snubber design specifications such that there was no reduction in the capability of snubbers to perform their design functions. The replacement snubbers met all previous design specifications (e.g. ASME Code, Section III design specification; functions; load capability; and environmental qualification). The 10 CFR 50.59 safety evaluation used was a previously documented "Equivalent Replacement and Document Update Generic Evaluation." The licensee had determined that this modification qualified as an equivalent replacement and as such was encompassed by the previously documented safety evaluation. The inspector reviewed the safety evaluation and discussed various aspects of it with licensee personnel. No deficiencies were noted.

The inspector reviewed the applicable UFSAR section and determined that following the complete replacement of the snubbers, section 3.9.3.4.6.1, Snubbers, would need to be revised. The section specified that mechanical type snubbers (PSAs) were used in seismic category I systems inside and outside the primary containment. At the end of the project, there would not be any mechanical snubbers in use. The licensee was already aware of this and indicated that the necessary UFSAR changes would be processed as part of the requirements for implementing design changes. No other discrepancy was noted.

The inspector observed a bench test of a PSA 1/4 snubber (OP-RC-204-SH001) which had just been removed from service. The test was performed as part of the required TS 10% sampling. TS 4.7.5.e.1 required that at least 10% of the total of each type of snubber shall be functionally tested either in-place or on a bench. The test was conducted per Work Order 970915029 and procedure SH.RA-ST-22-0105(Q), Rev. 0, Snubber Examination and Testing. The test instrument used was a "Wyle 150" snubber test stand. The certification of calibration of the test stand was up to date and traceable to the National Institute of Standards and Technology. The test was conducted satisfactorily and the snubber functioned as designed.

c. Conclusions

The licensee implemented the snubber surveillance program in accordance with technical specifications. The ongoing efforts to upgrade all plant snubbers appeared technically sound and was aimed at precluding problems previously experienced with snubbers. The individuals involved with the testing of the snubber appeared very knowledgeable and technically competent.

M2.4 "A" Core Spray Nozzle (N5B) Safe End Weld Pin Hole Leaks

a. Inspection Scope (73753)

The inspector reviewed licensee activities involving the pin-hole leaks identified in the "A" core spray nozzle (N5B) safe end weld.

b. Observations and Findings

On September 19, 1997, the licensee identified three pin hole leaks in the "A" core spray nozzle. The leaks were from the top of the weld connecting the nozzle to the safe end. The licensee notified the NRC of this situation as required by 10 CFR 50.72 (b) (2) (I) for a degraded/unanalyzed condition (Event Number 32962). The plant had been shutdown for a refueling outage when the leaks were identified. The nozzle/safe end configuration consists of the following: the nozzle from the reactor vessel welded to the safe end; the safe end (Inconel SB 166 material) welded to the safe end extension (Low Alloy SA 508 Cl I), which is welded to the injection piping. A thermal sleeve lining in the nozzle is welded to the safe end. The nozzle/safe end and safe end/safe end extension welds consisted of Inconel 182 (Ni-Cr-Fe) material. The SB 166 safe ends were installed in 1982, as a replacement for stainless steel material.

Initial PSE&G efforts to obtain a clear definition of the extent and nature of the flaw were unsuccessful. However, using a "Smart 2000" ultrasonic testing (UT) system, the licensee was able to identify a volumetric crack. There were three pinholes within 1.5 inches of each other, with the largest being about 1/16 inch.

The nozzle was examined as part of the ISI program last refueling outage (1995) and was not scheduled for inspection this outage. When the crack appeared to be Intra-Granular Stress Corrosion Cracking (IGSCC), the licensee retrieved the 1995 examination data of the weld area for further and independent reviews. In 1995, the examination method was UT and, at that time, the licensee did not identify any flaws in this particular area of the nozzle. However, a re-review of that data revealed that there was an indication that should have been identified. A pattern that could have been indicative of a flaw was found to be present. The licensee organized two teams to follow up on this issue. One team was tasked with conducting a root cause investigation and the other was tasked with determining the most appropriate repair methodology. The licensee conducted a review of previous examination data for all other nozzles in an attempt to determine the potential extent of the problem.

At the end of this inspection, the licensee had not reached a conclusion as to the nature of the flaw causing the through wall leak, however, their preliminary determination was that the crack was IGSCC-based on the following: industry experience with IGSCC in this particular location and environment, previous NDE data, previous repairs of the nozzle safe ends, and the type of material (182) in the nozzle weld. PSE&G continued to conduct more detailed reviews using independent contractors. For repairs, the licensee was pursuing the "Weld Overlay" method. This process would require NRC approval prior to implementation. This item remains open pending completion of NRC's review of the circumstances that caused the flaw to remain undetected until it resulted in a through wall leak from reactor coolant system pressure boundary. **(URI 50-354/97-07-02).**

c. Conclusions

The licensee demonstrated good efforts at addressing the core spray nozzle through wall cracking problem once it was identified. Good program management was demonstrated by the formation of two independent teams to concurrently conduct root cause investigation and determine the appropriate repair method. However, questions remain regarding the apparently inadequate ultrasonic test data analysis during the last refueling outage which allowed the flaw to remain undetected until it became self-disclosing.

M4 Maintenance Staff Knowledge and Performance

M4.1 Maintenance Observations

a. Inspection Scope (62707, 92902)

The inspectors directly observed numerous work activities at the station during the report period, including:

- Struthers-Dunn safety-related relay replacements
- 10-A-402 4160V Vital Bus undervoltage relay checks
- "B" and "D" station service water corrective maintenance
- "B" reactor protection system motor generator work

Additionally, several work orders and maintenance procedures were independently reviewed to assess their quality and completion. Action requests involving maintenance activities were evaluated to determine whether adverse trends were evident in work quality, procedure compliance, and supervisory oversight. The inspectors conducted frequent interviews with maintenance supervision and QA inspectors in formulating this assessment.

b. Observations and Findings

In recognition of recent poor work performance, PSE&G management conducted several site-wide "stand-down" meetings with maintenance personnel just prior to the refueling outage to reinforce expectations with regard to procedure compliance, attention to detail, and self-checking. Outage contractor technicians were present at these meetings. However, the inspectors judged that these sessions achieved only limited success in meeting their objectives. Specifically, while the inspectors did observe some maintenance activities during which good practices were evident (e.g. Struthers-Dunn relay work, rod block monitor channel calibrations), a large number of inspector- and QA-identified issues were raised which indicated either poor workmanship or lack of procedure adherence. Issues involving inadequate oversight of contract workers were apparent as well.

On September 18, 1997, the inspectors observed relay department technicians performing undervoltage device calibrations on the 10-A-402 vital bus in accordance with procedure HC.MD-ST.PB-0010 (Q). This procedure requires verbatim step-by-step compliance. However, while performing the testing as written, the technicians observed that a relay under test did not respond as expected, and decided to deviate from the established sequence of steps in the procedure to complete the activity. The inspectors questioned the technician's actions; the workers did not consider their actions contrary to procedural requirements. During subsequent inspector discussions with the workers' supervi[illegible], that individual recognized the workers' actions to be contrary to procedure compliance expectations. Corrective actions for this issue involved additional "standdown" sessions for relay department technicians and individual disciplinary actions.

On October 4, 1997, the inspectors reviewed a completed work order package, including applicable procedures, for reactor feed flow transmitter calibration checks. The inspectors discovered several discrepancies in the attached documentation, including missed signature approvals for several activities. In one case, technicians determined that a flow transmitter required re-calibration. According the work order and the attached instrument calibration data card, the calibration was completed successfully. However, the sections of the procedure (HC.IC-DC.ZZ-0030 (Q)) necessary to conduct the calibration were marked as "not applicable," indicating that they had not been used. Several other portions of the procedure were also not completed, including a listing of the test equipment used, transmitter reassembly instructions, and supervisory review and approvals. The inspectors determined that this issue, along with the relay technician compliance issue described above, were two examples of failures to implement required maintenance procedures, which was a violation of technical specification 6.8.1.a. **(VIO 50-354/97-07-03)**

Several other instances of poor maintenance quality and procedure compliance, largely involving contracted work, were also self- or QA-identified. For example, while in the process of removing blocking tags, equipment operators determined that control rod hydraulic control unit maintenance performed by contractor personnel was not yet complete even though the associated work orders had been signed off. QA inspectors noted that verification hold points in a service water piping repair procedure and a reactor vessel disassembly procedure were missed. Contract technicians bent a source range nuclear instrument guide tube during an under-vessel control rod drive mechanism replacement. An underwater camera was inadvertently drawn into a reactor jet pump inlet during in-vessel inspections. The "A" reactor water cleanup pump was inoperable for more than four weeks while maintenance technicians attempted to correct pump seal leakage and motor vibration problems. This latter issue resulted in increased radiation exposures and extended operation with degraded reactor chemistry.

The inspectors discussed each of these events with station management, and determined that they were fully cognizant of the issues involved and were devising and implementing corrective measures to address the immediate concerns as well as minimize the potential for future occurrences. Maintenance management recognized the need for increased oversight of contract workers, and planned to devote more supervisory resources toward this effort.

c. Conclusions

In spite of proactive measures by PSE&G management to reinforce expectations regarding maintenance procedure adherence and attention-to-detail, several issues involving violations and poor work quality were identified. Supervisory oversight of contract maintenance technicians was weak.

M7 Quality Assurance in Maintenance Activities

M7.1 Problem Identification in Maintenance

a. Inspection Scope (62707)

The inspectors evaluated the effectiveness of PSE&G's controls in identifying and resolving problems in maintenance by reviewing corrective action program performance indicators, action requests, and root cause analyses, and by interviewing various plant staff and supervision.

b. Observations and Findings

PSE&G personnel nearly doubled the initiation rate of action requests since the beginning of the refueling outage, which began three weeks into the report period. The inspectors attributed this increase to the greater volume of work activities being conducted during the outage, coupled with continued good focus on documenting "low threshold" concerns. Every new action request was collectively reviewed by the Hope Creek management team at a daily meeting. Root cause analyses were required and completed when necessary. The inspectors observed good critical reviews of each issue, and noted that identified deficient conditions were added to the outage work scope as appropriate. Most issues involving poor or inadequate maintenance practices were documented by maintenance department personnel, though several maintenance-related action requests were initiated by quality assurance, operations, and engineering staff.

In spite of the generally good performance, the inspectors noted delays in initiating several action requests involving conditions adverse to quality. For example, the NRC-identified issue involving feed flow transmitter procedure adherence (see section M4.1) was not documented until five days after the discrepancy was raised, and only then because of inspector prompting. An issue involving foreign material dropped into the reactor cavity was not documented until nearly a week after the event occurred. A discovery by the maintenance manager conducting field observations that technicians had failed to properly "log on" to a work order was not documented in an action request. The inspectors judged that in these and other events station personnel failed to meet PSE&G management expectations for documenting problems identified at the station.

c. Conclusions

PSE&G personnel continued to document deficient conditions at the station with a low threshold for initiation. Plant management demonstrated good reviews of each new issue and required resolution during the refueling outage when appropriate. However, several issues were not documented in a timely manner to ensure timely review and corrective action.

M8 Miscellaneous Maintenance Issues

M8.1 (Closed) VIO 50-354/E 96-014-01013: repeat failure of residual heat removal system shutdown cooling common suction line mechanical snubber. The inspectors reviewed PSE&G's response to this violation and judged the stated corrective actions to be reasonable and complete. The inspectors independently verified that increased testing conducted on the subject snubber was completed appropriately and that no further failures were experienced. As such, the inspectors judged that procedure changes incorporated following the most recent failure, which modified the method used to place shutdown cooling in service, were effective and prevented recurrence. Additionally, the inspectors noted that this particular snubber was replaced during the current refueling outage with an improved design hydraulic snubber.

M8.2 (Closed) VIO 50-354/97-02-01: failure to shut emergency diesel generator (EDG) cylinder test cocks prior to engine operation. The inspectors reviewed PSE&G's June 20, 1997 letter which responded to this violation, and judged the stated root cause and corrective actions to be reasonable. PSE&G attributed the cause of the event to human error, and implemented disciplinary actions as necessary. Additionally, the inspectors verified that the surveillance test and operating procedures were revised to require independent verification of test cock closure prior to future EDG operation.

M8.3 (Closed) LER 50-354/97-018: engineered safety feature actuations as a result of reactor protection system (RPS) motor generator set output breaker trip. PSE&G determined that the August 3, 1997 trip was caused by an age-related component failure on the associated breaker underfrequency monitor, which is not safety-related. This event resulted in the unplanned loss of "B" RPS power, which in turn caused automatic isolations of the reactor water cleanup system, reactor water sample system, and steam line drain headers, as well as a "half" scram. The inspectors verified that the underfrequency monitor was replaced and appropriately re-tested. Additionally, PSE&G developed a recurring task to periodically perform functional testing on this device to ensure future reliable operation.

III. Engineering

E1 Conduct of Engineering

E1.1 Plant Modifications - Configuration Changes

a. Inspection Scope (37550)

The inspectors reviewed four design change packages (DCPs) focusing on design change program implementation and the licensee's review of the plant configuration changes to ensure that the criteria delineated in 10 CFR 50.59 and 10 CFR 50, Appendix B, "Design Control," were met. On a sampling basis, specific DCP items reviewed included: scope of design change, basis for the design change, 10 CFR 50.59 applicability review and safety evaluation, applicable calculations, drawing and plant procedure revision, post-modification testing, and acceptance criteria. Some field walkdowns were also conducted.

b. Observations and Findings

The inspectors review of DCPs 4HE-0245, Revision 0, "Elimination of Flow Signal Noise on Dead Leg Transmitter"; 4HE-359, Revision 0, "Main Steam Line Continuous Drain Flow Orifice Resizing for MW Improvement"; 4EC-3644, Revision 0, "Standby Diesel Generator/CO2 System Modification"; and 4HE-0170, Revision 0, "Reactor Vessel Wide Range RCIC Level 8 Channels Relay Replacement"; determined that, in general, engineering had done an acceptable job to review the issue and develop a design change to resolve the issue.

The inspectors found that the DCPs included sufficient documentation to permit evaluation of the effect of the changes on the design and licensing basis. Where applicable, the engineer had prepared appropriate calculations to justify acceptability of the design. No concerns were identified with three calculations reviewed. Complete review of one of the packages determined that it included necessary procedure and drawing changes, acceptable installation instructions, and appropriate retest instructions. Walkdown of two design changes confirmed acceptability of the installation. Except as noted below, acceptable 10 CFR 50.59 applicability reviews had been prepared for the DCPs and proper peer review and safety operation review committee (SORC) approval, as directed by the procedures, had been obtained. The inspectors further confirmed that the UFSAR and design basis documents had been updated after the design changes.

Engineering Change Authorization 4HE-0170

This design modification involved the replacement of Agastat GP series relays in the reactor core isolation cooling (RCIC) turbine trip logic with Agastat TR Series time delay relays. The purpose of the time delay was to prevent a RCIC level 8 trip due to instrument "ringing" caused by oscillatory transmitter signals during reactor transients. The signals to the timers were derived from the reactor vessel wide range level 8 channel instrumentation. PSE&G later evaluated the time delay and found it to be acceptable.

To verify that the added time did not impact the system function and other emergency actuation signals, the inspectors reviewed applicable sections of the UFSAR. They determined that the signals to other functions initiated by the same level instrumentation were unaffected by the change. The inspectors also observed that the 10 CFR 50.59 applicability review form, prepared by the licensee to determine whether a 10 CFR 50.59 safety evaluation applied, did not include a review of Section 7.4.1.1 of the UFSAR which describes the functions and operation of the RCIC system. This section also includes a flow control diagram that should have been revised to reflect the design change.

Because a review of the above UFSAR section was not done, PSE&G engineering improperly answered "no" to the question of whether the modification changed the facility as described in the FSAR and failed to perform a safety evaluation to ensure that the change did not involve an unreviewed safety question. A peer and approver review of the applicability review form also failed to recognize this deficiency. This is a violation of 10 CFR 50.59 requirements. **(VIO 50-354/97-07-04)**

c. Conclusions

The program for designing and installing configuration changes to plant systems was acceptable. However, inadequate review of design documentation prior to implementation of a reactor core isolation cooling system modification resulted in a violation of 10 CFR 50.59 requirements in that no written safety evaluation was performed for the change as required. This failure was also an example of weak implementation of the peer review process.

E2 Engineering Support of Facilities and Equipment

E2.1 Engineering Support of Plant Operations and Maintenance

a. Inspection Scope (37551, 62707, 71707)

The inspectors evaluated engineering department technical support following plant events and during equipment maintenance activities. Reviews of design change package implementation during the refueling outage were conducted. Root cause analyses performed by engineering personnel in support of identified degraded conditions were assessed. Additionally, the inspectors compared UFSAR system descriptions and design bases information to actual plant conditions.

b. Observations and Findings

The inspectors observed good system engineering involvement in troubleshooting activities following plant events and other adverse conditions. For example, system engineers actively participated in the resolution of the September 2, 1997 "A" reactor recirculation pump trip event and the condition evaluation of the "A" main output step-up transformer following the September 10, 1997 manual reactor scram. The inspectors also noted good follow up and evaluation of increased unidentified drywell leakage rates during the last ten days of the operating cycle. Engineering department response following the identification of the through-wall leak on the "A" core spray reactor pressure vessel nozzle was appropriate.

PSE&G experienced several repeat equipment failures during the report period, which indicated that past engineering resolution to degraded conditions were less than fully effective. The rod sequence control system was declared inoperable following a repeat failure of the self-test logic on September 9, 1997. A failed "inop/inhibit" switch on an intermediate range neutron monitor (IRM) channel caused an unexpected half-scram signal, nearly identical to previous occurrence on a different IRM channel earlier in 1997. The scope of corrective actions for the earlier event did not include inop/inhibit switches on the redundant IRM channels.

The inspectors reviewed a root cause evaluation stemming from an action request which documented problems experienced during maintenance on the "A" reactor water cleanup pump. This planned five day on-line maintenance activity required more than one month to complete, and had an observable negative impact on reactor water chemistry. The root cause evaluation was very critical of both engineering and maintenance department performance, and highlighted several problems with inter-departmental coordination, data collection and evaluation, contingency planning, and troubleshooting. The inspectors noted that eight separate corrective actions were recommended, which addressed both specific and generic concerns raised in the evaluation.

PSE&G engineering developed approximately thirty design changes for implementation during the refueling outage, a large percentage of which were intended to eliminate long-standing equipment deficiencies, including temporary modifications, operability determinations, and operator workarounds. Examples included reactor recirculation pump seal upgrades, safety-related relay replacements, rod sequence control and rod worth minimizer modifications, and service water pump discharge strainer improvements. However, several of the change packages were of poor quality, as evidenced by a high number of in-process package modifications. Based on inspector discussions with engineering and maintenance personnel, many of these self-identified package deficiencies could have been prevented had more detailed reviews been conducted during development and had more time been allotted for pre-implementation walkdowns. Several packages, like the emergency diesel generator (EDG) relay replacement work, did not specify adequate retests. This package required only that the monthly EDG surveillance run be conducted, in spite of the fact that many of the relay functions affected by the modification would not be verified by this test.

c. Conclusions

System engineering efforts in identifying and resolving emergent equipment failures were prompt and effective. The large scope of design change work scheduled for completion during the refueling outage demonstrated appropriate management focus on resolution of long standing equipment deficiencies. However, several examples of repeat equipment failures, extended system maintenance activities, and design change package deficiencies highlighted weakness in the quality of engineering support. An internal review of an extended reactor water cleanup pump outage was thorough and self-critical.

E2.2 Engineering Involvement in Site Activities

a. Inspection Scope (37550)

The inspectors evaluated the effectiveness of the engineering staff in supporting plant needs through a review of licensee event reports (LERs) and root cause analysis reports in the area of engineering, interviews of responsible engineering personnel, and an assessment of the quality of the analyses performed to resolve the reviewed issues.

b. Observations and Findings

Thermal Degradation of Struthers-Dunn Relays

On April 7, 1997, PSE&G notified the NRC via LER 50-354/97-07 of the results of an evaluation they had performed regarding an increase in Struthers-Dunn relay failures: they had experienced approximately 40 relay failures between 1988 and 1996 and 24 in the last three years. PSE&G concluded that the relay failures were due to thermally-induced aging of a magnetic vinyl plastic used as bearing pad material. As determined by licensee engineering personnel, the failure of the bearing pad affects the alignment between the armature and the ac relay coil and causes rapid oscillatory motion of the relay armature and contacts. This rapid motion eventually results in relay failure. The observed degradation involved normally-energized relays.

To determine the extent of relay degradation, the licensee conducted walkdowns of 51 Class 1E panels containing Struthers-Dunn 219NE series relays. They identified a total of 48 degraded relays. PSE&G considered a relay to be degraded if pieces of bearing pad material were visible at the bottom of the relay case. All degraded relays, except three, were in a mild environment; almost all of the mild environment relays were mounted in the remote shutdown panel.

The root cause analysis performed by the engineering team was thorough with many background details, including vendor assessments. A number of corrective actions resulted and, as of the end of the inspection, all degraded relays had been replaced. The inspectors, however, identified several concerns:

- The walkdown considered degraded only those relays having visible debris in the relay case. The basis for this was an understanding that a degraded relay would first begin to chatter and that several days or weeks of continuous chattering would be required before the relay failed due to contact sealing (arcing) or spring fatigue.

  The inspectors judged this reasoning to be less than acceptable, because it did not consider the effect of a seismic event on those relays that showed no evidence of "degradation" and, therefore, it did not evaluate their ability to perform their safety functions. While the relays in question were in a mild environment, the number of failures also in panels considered to operate at a lower temperature indicated that aging was pervasive. Therefore, the decision to conduct weekly panel walkdowns and inspect for buzzing was similarly less than acceptable. For these relays, the adequacy of the walkdown and the service life of the relays is unresolved pending appropriate evaluation by the licensee and review by the NRC **(URI 50-354/97-07-05)**

- For five Struthers-Dunn relays identified during the plant walkdown that were located in a harsh environment, calculation No. STRDUN-ARRH-001, dated April 30, 1997, determined that the normally-energized qualified life was 15.4 years. For this calculation, engineering took coil and pad material temperature readings; then, they used these measured temperatures to calculate the relay qualified life using the Arrhenius method of extrapolation. The inspectors did not identify any errors in the calculation itself and had no comments regarding the calculation method. However, considering that three of the five relays in question were "degraded" after only eleven years and without taking into consideration the post-accident operability period, the inspectors concluded that the inputs (activation energy and/or operating temperature) to the equation had to be incorrect, if the temperature-aging relationship postulated by Arrhenius had to hold true. The calculation results were not adjusted to reflect observed conditions and no explanation for the difference between calculated and actual qualified life was provided. Four of the five relays in harsh environment were replaced. An appropriate justification had been prepared for not replacing the fifth relay.

- The equipment evaluation summary sheet (EESS), revised to add the five harsh environment relays, established the qualified life of the same relays at twelve years. For other Struthers-Dunn relays in the same panels, the EESS specified the qualified life to be 5.04 years. The EESS provided no explanation for the difference in qualified life.

The failure to include the noted five harsh environment relays in the environmental qualification master list and to replace them after their qualified life constitutes a violation of 10CFR 50.49 requirements. **(VIO 50-354/97-07-06)**

While reviewing the EESS for the Struthers-Dunn relays, the inspectors observed that the postulated post-accident relative humidity (RH) environment was 100%, but that the relays were qualified for only 90-98% RH. PSE&G accepted the RH qualification "based on analysis of test instrument accuracy" (Note 5 of the EESS). Because instrument accuracy can also be nonconservative, the inspector questioned the adequacy of the justification. Following the inspection, the licensee provided additional documentation that demonstrated qualification of the relays in a postulated 100% RH environment.

Additional observations regarding relays in both harsh and mild environments are included in Section E2.3 below.

c. <u>Conclusions</u>

The inspector concluded that the licensee took generally acceptable actions to address nonroutine plant events. When a root cause analysis was prepared, the analysis was thorough and detailed. Not all conclusions were conservative, however, as in the case of the Struthers-Dunn relays in a mild environment.

For Struthers-Dunn relays in harsh environment, the failure to include five relays in the EQ list and to replace them at the end of the qualified life resulted in a violation of 10 CFR 50.49. Also, the use of a calculated relay qualified life without reconciling the difference with actual data indicated an excessive reliance on a theoretical life extension method that is highly dependent on the correct selection of independent variables.

The delay in initiating a relay failure analysis (24 relay replacements in three years) indicated a weakness in the program for monitoring the performance of safety-related components in a mild environment.

E2.3 <u>Service Life of Relays in Mild Environment</u>

a. <u>Inspection Scope (37550)</u>

Information Notice (IN) No. 84-20, "Service Life of Relays in Safety Related Systems," advised licensees that the service life of all relays in the normally energized state is significantly shorter than when used in a cycled or normally deenergized application. The notice also advised that preventative maintenance programs should recognize the application-dependent service life of the relays and that it may be prudent to increase the frequency of surveillance activities of those systems where the surveillance interval was not small in comparison with the service life of the relays in those systems. Because LER 50-354/97-07 indicated an increase in failures of normally energized Struthers-Dunn relays, the purpose of this portion of the inspection was to evaluate the actions taken by the licensee to address the service life of normally energized relays other than Struthers-Dunn.

b. Observations and Findings

Hope Creek was still under construction when IN 84-20 was issued. However, in a letter to PSE&G, dated May 13, 1986, the Architect-Engineer (AE) provided a table of the normally energized relays used at Hope Creek and their service life. A review of this letter and attached table showed that, for some relays, the service life was very short. For instance, the service life of Potter & Brumfield, 24 Vdc MDR relays and for Telemechanique J13 and J14 relays the service lives were stated to be 2.2 and 3.77 years, respectively. The letter also stated that General Electric (GE) had extended the life of the Agastat FGP and EGP normally energized relays from the 4.5 years specified in the IN to 5.9 and 6.6 years, depending on the ambient temperature inside the relay panels.

Apparently, because of "human error and organizational/programmatic problems," as stated in Action Request (AR) 00970218207, the AE's recommendations were not put into action. The AR also stated that the relay changes were to be accomplished "through the Mild EQ program which was canceled. No group inside or outside of HC took ownership of the issue."

Potter & Brumfield Relays

For the Potter & Brumfield relays, the licensee had neither recalculated the service life nor taken measures to replace them after the expiration of the service life that had been calculated by GE. However, when the inspectors identified the concern, they recalculated the service life of the relays and determined it to be 12.18 years. The revised service life was based on: (1) the relays being energized 25% of the time; (2) an operating temperature of 85° F; and 3) a coil temperature rise (while the relay is energized) of 60° C.

The inspectors reviewed the preliminary calculation provided by the licensee and considered the results acceptable, primarily based on the conservative value of energization factor (25%). Data provided by the licensee indicated this to be less than 20% since reactor criticality in April 1986. However, the inspectors made the following observations:

- Since the relays are energized when the reactor is shutdown, the licensee should estimate the energization period prior to commercial operation. This could greatly impact the replacement date.

- The operating temperature of the relay was assumed to be 85° F. The licensee should confirm the reasonableness of this value and justify the difference between the values used in the calculation and those used by General Electric in their qualification report.

- Since the temperature rise (calculated by resistance measurement) changes with the operating temperature, its value should be recalculated more accurately.

Telemechanique J10 and J13 Relays

The licensee stated that Telemechanique (also known as Gould and ITE) J10 and J13 relays are used only in the emergency diesel generator panels. These panels contain 42 normally energized relays each.

On April 3, 1992, the NRC issued IN 92-27 to inform the industry about thermally-induced aging failures of ITE/Gould J10 relays at Seabrook and Millstone. At Millstone the relays had been in operation for seven years. On March 21, 1997, the NRC issued a supplement to this IN describing similar failures at the Beaver Valley plant. At Beaver Valley, the relays had been in operation for nine years.

In an internal memorandum dated January 24, 1996, PSE&G engineering stated they had submitted to seismic tests two naturally-aged relays selected among those showing most degradation (discoloration). These tests showed that the relays, in their current aging condition, would have been capable of performing their safety function during and following a seismic event, had they been required to do so, The memorandum also stated that the relays would be submitted to accelerated aging equivalent to one plant operational cycle and retested seismically to prove their ability to perform their function through the 1997 refueling shutdown. This was done and because of the successful results, the licensee eventually decided to further extend the service life of these relays for one additional operational cycle.

Nuclear Environmental Qualification Report No. 96030.1, Revision 0, prepared by Farwell and Hendricks (F&H), shows that the relays were subjected to accelerated aging for 182 hours at 140° C and that the aging time was calculated, using the Arrhenius equation, assuming an additional required service life of 21 months at an ambient temperature of 50° C. The F&H calculation also assumed a coil temperature rise of 28° C. However, this value was incorrect because in the above referenced memorandum the licensee stated that they had taken temperature rise measurements and, with one relay energized in the center of three relays ganged together, they had measured the temperature rise to be 92.3° F, equivalent to 51.28° C

To be conservative, the licensee should have measured the temperature rise of the center relay with all three relays energized, unless an analysis demonstrated that the physical configuration reflected the tested configuration. However, as a minimum the F&H calculation should have used the measured temperature. If a temperature rise of 51.28° C was used in lieu of the 28° C in the Arrhenius equation, the 182 hours accelerated aging used by F&H would have yielded only 97 days of operating time, not 21 months. The licensee did not address this discrepancy. Because the relays are in a mild environment and underwent complete seismic testing (five operating basis and one shutdown earthquakes) three times, the inspectors had no immediate safety concern with these relays. However, the use of the lower temperature rise in the life extension calculations was inappropriate.

Agastat Relays in a Mild Environment

Performance Improvement Request (PIR) 951120103 indicated that there were 1197 Agastat relays at Hope Creek. Ninety-one of these were in harsh environment and covered by the plant equipment qualification program. The remainder, of which approximately 330 were normally energized, were located in mild environment zones.

As stated previously, IN 84-20 informed licensees that the service life of normally energized GP/EGP type relays is 4.5 years based on GE test data. For GE supplied Agastat relays, GE extended the service life to approximately 6.5 years. This was done through either an evaluation of the ambient temperature to which they are exposed, as stated in the May 1986, AE letter to the licensee, or through a material analysis of relays that had been in service for four years, as related in corrective action no. 2 of PIR 970218207. PSE&G stated that, for those relays, replacement occurred at 6.5 year intervals and that recurring tasks (to replace the relays at the stated interval) existed. For non-GE-supplied normally energized relays, PSE&G set the service life at 10 years, apparently based on the service life that had been established by the AE for the EGP relays in 125 Vdc and 250 Vdc battery chargers. No recurring tasks existed to replace most of these relays.

In November 1995, approximately six months prior to the expiration of the relays service life, the licensee found that, for certain Agastat relays, no recurring task existed. The ensuing PIR (No. 9511200103) resulted in a detailed review by the licensee of the Agastat relay service life issue. Originally, the service life was calculated to be 11 years, placing the end of the service life on April 16, 1997. No formal calculation was performed, however, for the 11 years. In an attempt to extend the service life further, the licensee decided to conduct life extension tests. For this purpose, the licensee selected two E7000 and two EGP type relays that had been naturally aged in the plant and sent them to a laboratory for testing. It was not clear whether these relays were representative of the lot, also considering that one of the EGP relays later was found to be new.

The inspectors' review of the test report determined that the E7000 relays passed the seismic test after an equivalent of 27 months of aging. The aged EGP relay, however, with an equivalent of only seven months aging, failed the seismic test. Because the design basis earthquake is an event during and after which equipment in mild environment must remain functional, its failure after a relatively small amount of additional aging time was significant because it indicated the possibility that the relay might have not passed the same test, even in its preaged state. Because the relay failed to withstand the seismic test, all normally energized relays were replaced after eleven years.

In determining the amount of accelerated aging required to extend the service life of the EGP relays specified by the licensee, F&H used a temperature rise of only 32° F (17.7° C). This same value was also used by the licensee in service life calculation Agastat-ARRH-002. However, the accuracy of this value is doubtful because it is consistent neither with temperature rise data available to the licensee for other relays, nor with measurements taken by GE and others for the same relay. For instance, (1) the temperature rise measured by the licensee for an energized J10 relay was 85° F; (2) qualification records provided by the licensee for the 115 Vac and 24 Vdc MDR relay showed that, at normal ambient temperature, the temperature rises were 72 and 108° F, respectively; and (3) licensee-performed service life calculations for Struthers-Dunn relays used a temperature rise of 105° F. Measurements taken by GE and, more recently, by another licensee, show that the energized Agastat EGP relay coil temperature rise is approximately 100° F. The use of a realistic temperature rise in the aging calculation greatly reduces the life expectancy of the energized relays.

Regarding the E7000 series relays, F&H concluded that the service life could be extended by 27 months. In the accelerated aging time calculation, F&H used a temperature rise value provided by PSE&G. This value, 34° F (18.9° C), appeared to be similarly unrealistic and not in conformity with expected values. If the licensee had used a value 75° F, for instance, which is in the lower range of the heat rise measurements for J10, MDR and Struthers-Dunn relays, the amount of service life extension they would have achieved through the F&H accelerated aging would have been less than three months, not 27 months.

The inspector judged that the failure to employ appropriate values in relay service life calculations was a violation of 10 CFR 50, Appendix B, Criterion III, in that appropriate design control measures were not established. **(VIO 50-354/97-07-07)**

Agastat Relays in Harsh Environment

In conjunction with this review, the inspectors determined that ninety-one E7000 and ETR Agastat timing relays are used in a harsh environment. The ETR relays are equivalent to the Agastat EGP relays. The applicable EESSs stated that the relays are required to operate 100 days in a post-accident environment with a maximum temperature of 148° F, and 100% RH. The EESSs also stated that the relays are qualified for this environment and that they have a service life of 4.95 years. The inspectors review of the EESS identified several concerns:

- The original calculation, Agastat-ARRH-001, Revision 0, that evaluated the qualified life of these relays, apparently no longer exists. Therefore, the accuracy and bases for the stated qualified life could not be verified. New calculations showed the service life to be longer than the stated 4.95 years. However, these calculations assumed a coil temperature rise of 34° F. Therefore, the results may not be accurate.

- The EESSs stated qualification to greater than 148° F. However, for relays that remain energized during and following the postulated accident, qualification may not be demonstrated by the manufacturer's tests.

According to the Amerace test reports, the relays were aged (in the deenergized state) at 212° F. In addition, they were subjected to a "hostile" environment for two hours at 95% RH and at each of nine temperatures ranging between 40 and 172° F. During the "hostile" environment test, the relays were energized only during functional tests. The relays were functionally tested at their minimum and maximum design voltages ten times (five times at each voltage level) during each two-hour period.

At an ambient temperature of 148° F, when margin (15° F) and panel and coil heat rise are considered, the operating temperature of the energized ETR relays is expected to be approximately 250-255° F, i.e., well above the aging and "hostile" testing temperatures. For the energized E7000 relay, qualification to the specified post-accident temperature would be demonstrated only if the coil heat rise remained below approximately 40° F.

- Note 3 of the EESSs stated that, although the relays had been qualified for only 95% RH, qualification could be extended to 100% RH because "heat of the current carrying components in the panels will raise their internal temperature above the surrounding ambient temperature effectively reducing the R.H." Because, following an accident, the panel internal temperature is suddenly increased by approximately 50° F, it was not immediately evident that the RH within the cabinets would not also be at 100%.

Following the inspection, the licensee determined that the ETR relays had an energized duty cycle of 10%. In addition, they provided an analysis showing that a 2° F difference between the internal and external temperatures would reduce the panel internal RH to 95%. The issue concerning the qualified service life of the Agastat relays in a harsh environment is unresolved pending appropriate revisions to the aging calculation. **(URI 50-354/97-07-08)**

c. <u>Conclusions</u>

Less than acceptable judgement was used in the selection of the coil temperature rise of normally energized, safety-related Telemechanique and Agastat relays in a mild environment. As a result, their calculated service life was longer than what industry experience (NRC information notices) supported. Because of the incorrect temperature rise, life extension tests were similarly unsupported.

Acceptable justification was provided to demonstrate qualification of the ETR relays to the specified post-accident environment. However, the qualification of the normally energized E7000 series relays to the post-accident environment is unresolved pending the licensee's confirmation that the coil heat rise is less than approximately 40° F.

The licensee acknowledged the findings presented, but disagreed with the inspectors' conclusions regarding the relays located in a mild environment, stating that an adequate relays monitoring program existed.

E7 Quality Assurance in Engineering Activities

E7.1 Audits and Assessments

a. Inspection Scope (37550)

The inspectors reviewed audits and assessments to determine the effectiveness of the licensee's self assessment program in engineering.

b. Observations and Findings

The inspectors reviewed QA audit 97-100, the final report for the SSWS (July 18, 1997), and several Hope Creek quality assessment surveillance reports. The review indicated a good audit program with good plans in place. The inspectors found that the assessments were broad in scope and presented substantial findings and observations including recommendations for those engineering programs or processes requiring additional management attention. Engineering areas reviewed included design and control, configuration control, corrective action program, self-assessment and previous QA audit findings, reactor engineering/fuels, engineering cultural assessment, and training and qualification. The inspectors noted that the findings were clearly stated, directed to the appropriate personnel, and assigned tracking numbers. In addition, the inspectors verified appropriate resolution of selected findings.

c. Conclusion

The inspectors concluded that the QA audit of Hope Creek engineering was good and provided a good assessment of the engineering programs in place.

E8 Miscellaneous Engineering Issues

E8.1 Medium Voltage Circuit Breaker Failure

On September 10, 1997, PSE&G notified the NRC that the plant had been manually scrammed due to an inoperable 'A' main phase transformer. The notification also stated that, during plant restoration following the scram, the 'A' secondary condensate pump [circuit breaker] failed to trip. Although the secondary condensate pump and the supply circuit breaker are not safety-related components, the purpose of the inspection followup was to determine the causes of the breaker failure to open on demand and to evaluate potentially generic implications.

The inspectors' walkdown and review of this issue determined the following:

- The failed circuit breaker was manufactured by ITE/Gould and used in a 7.2 kV nonsafety-related application.

- The medium voltage (4.16 kV) breakers used in safety-related applications were also manufactured by ITE/Gould.

- PSE&G was conducting a root cause analysis of this failure and, although had not reached definite conclusions, was attributing the breaker failure to a failed trip coil.
- In a separate incident, but during the same event, with the bus de-energized a turbine building chiller supply breaker closed on a dead bus and cycled six times before it finally opened. This breaker failure was being reviewed by engineering, but apparently it was viewed more as a control circuit issue.
- The preventive maintenance program for safety and nonsafety-related medium voltage circuit breakers is similar and involves primarily the electrical (high voltage) portion of the breakers, but not the operating mechanism. Preventive maintenance was scheduled every 36 months.
- Twenty nine circuit breakers underwent a complete overhaul during the previous refueling outage and an additional nineteen were scheduled for the current outage. Some circuit breakers (including the failed ones) were never overhauled since their shipment, i.e. prior to initial plant startup.
- At the time of the inspection no information was available regarding vendor recommended overhauling scope and schedule.

Because the licensee's analysis was incomplete, the inspectors did not pursue this issue further. They did, however, express a concern regarding breaker maintenance. This issue remains open pending completion of the analysis by the licensee and review by the NRC. **(URI 50-354/97-07-09)**

E8.2 (Closed) VIO 50-354/96-04-01: Failure to account for all Bailey solid state logic module (SSLM) failures. The establishment of a reliability program to monitor the performance of the Bailey 862 SSLMs is a Hope Creek license condition (2.C.5) requirement. To implement this program, PSE&G issued procedure HC.IC-DD.ZZ-0017(Z), "Bailey Module Reliability Program," which required that work sheets for all rework, repair, replacements, and/or testing of any type of modules be sent to the system engineer for review and failure characteristic analysis. During the April 1996 inspection, the NRC determined that PSE&G personnel had not been consistently complying with the procedural requirements.

To address this issue, PSE&G initiated a root cause analysis. They determined that, during the first quarter of 1996, work sheets had either not been completed or delivered to the system engineer on eight of the ten cases. Additional examples of procedure noncompliances were identified in 1995 (5 of 19 instances) and 1994 (3 of 21 instances). They concluded that the root cause of their failure to comply with the procedure requirements was inadequate program monitoring by maintenance, engineering, and quality assurance personnel.

In their response to the notice of violation (letter LR-N96180, dated July 5, 1996), PSE&G indicated that they would revise the applicable procedures to require system engineering signature prior to closure of the work order, conduct appropriate training, counsel personnel involved, and monitor the effectiveness of the corrective actions.

During the current review, the inspectors examined the results of root cause analysis, evaluated the adequacy of the corrective actions, and confirmed that such actions had been completed. Based on this review, the inspector concluded that acceptable actions had been taken to address the violation and the item is closed.

The licensee's internal closure of this issue included a reportability review. PSE&G concluded that the event was not reportable (as required by license condition 2.F) because they had established a program to comply with the license condition, but just failed to comply with the procedures that implemented the program. The inspectors disagreed with PSE&G's conclusions because the effectiveness of the program relied solely on the personnel complying with the procedural requirements. PSE&G's review of their past performance in this area identified procedural noncompliances in each of the three years reviewed, especially in 1996 when they failed to comply with the applicable procedures eight out of ten times. Therefore, a successful monitoring program and, hence, compliance with the intent of the license condition could not be claimed.

Because the licensee originally identified the procedural noncompliance, a notice of violation was already issued for such noncompliance, and acceptable steps were taken to address the monitoring concern, this minor violation of the licensee's reporting requirements is not being cited in accordance with section IV of the NRC Enforcement Policy. **(NCV 50-354/97-07-10)**

E8.3 (Closed) URI 50-354/96-04-02: Control of the Bailey solid state module automatic tester programs. Testing of Bailey cards is primarily accomplished through the use of an automatic tester in accordance with procedure HC.IC-GP.ZZ-0075(Q). During the 1996 audit, the NRC inspectors determined that the tester stored approximately 200 different programs and that the revision of these programs was being controlled by the plant design change process. The inspectors also determined that the programs were being backed-up every six months and stored on site. However, they were unable to determine the storage location, or the method of storage and access control of the backed up media.

Following the inspection, the licensee evaluated the NRC concerns regarding storage of the backed up media and determined that they did not have a procedure to control the software of the logic module tester. The root cause analysis team assembled to address this issue examined its significance based on past practices. They determined that, in the past, the program always had been updated by the vendor who was responsible for verifying the accuracy of the changes and maintaining control of the program configuration.

The team also determined that the database, also required by the tester, was controlled through the plant modification process. Design changes that impacted the Bailey logic modules were routed to the responsible engineer who would modify the database. The database changes, password protected, underwent appropriate design verification. Tests followed hardware and software changes. Periodic tapes of the tester program were made by the vendor. The database was copied on the tape at the same time.

Based on their review of past practices, tester performance, and test results, the team concluded that the issue was not a safety concern. They realized, however, the need for better software configuration control. Toward this end they initiated several actions, including: (1) issuance of program and database software as controlled documents; (2) revision of procedure for programming new chips; (3) preparation of procedures for changing the tester database and for performing backup and restoration to and from tapes; and (4) issuance of the Bailey Card Tester Manual as a controlled manual. In addition, they required that all departments verify that safety-related and critical software complied with the software configuration requirements of procedure NC.NA-AP.ZZ-0064, "Software and Micro-Processor Based Systems."

Based on their review of the root cause analysis and verification that the required actions had been completed by responsible groups, the inspector concluded that acceptable actions had been taken to address the NRC concern regarding control of the tester software. This item is closed.

E8.4 (Closed) IFI 50-354/96-04-03: Bailey solid state logic module electromagnetic interference circuit testing. The Bailey cards experienced a high rate of failures during plant startup that was attributed to electro-magnetic interference (EMI) and high humidity. To address these issues, the cards were modified to provide a larger gap between the circuit input traces and to add EMI input buffer circuits. It was not clear, however, that the modifications were in place during subsequent temperature and seismic tests.

During the current review, the inspectors reviewed Bailey Controls Report number QR-3101A-E93-75, dated October 7, 1985, and PSE&G drawing PJ200Q-2994, dated January 17, 1985. Based on this review and discussions with licensee personnel, the inspectors concluded that the SSLM modifications had been installed prior to the seismic and temperature qualification tests. This followup item is closed.

E8.5 (Closed) IFI 50-354/96-04-04: UFSAR inconsistencies. While reviewing UFSAR sections related to the inspection of the Bailey solid state logic modules, the NRC inspectors observed some inconsistencies between the UFSAR wording and plant practices, procedures and/or observed parameters. Specific UFSAR sections cited in the inspection report included Sections 7.1.2.9.2, 7.3.1.1.9, and 7.3.1.1.10, and Tables 7.1-2 and 7.1-3.

In their response to the NRC observations (Letter No. LR-N96180, dated July 5, 1996), the licensee confirmed that the UFSAR sections were misleading regarding methodology of system testing and stated that the sections would be revised appropriately. Regarding Tables 7.1-2 and 7.1-3, PSE&G stated that they had reviewed the testability guidance contained in Regulatory Guide (RG) 1.22 and the

Hope Creek Safety Evaluation Report (SER) and determined that they complied with Regulatory Position D.4.a, b, c, and d of RG 1.22 and that their compliance with this regulatory position was documented in Section 7.3.2.5 of Supplement 6 to the SER.

The inspectors confirmed that the applicable UFSAR sections had been revised and verified that testing practices conformed with the guidance of the applicable sections of the RG and SER. This item is closed.

E8.6 (Updated) VIO 50-354/96-09-03: Interaction between nonsafety and safety-related components in the standby diesel generator room ventilation system. NRC inspection report 50-354/96-03 described a concern regarding potential interaction between the nonsafety-related fire suppression system and the safety-related standby diesel generator room ventilation system. Subsequent review of this issue resulted in the issuance of a notice of violation on December 5, 1996.

In their response to the notice of violation, letter No. LR-N96436, dated January 9, 1997, PSE&G stated that a temporary modification had been implemented to disconnect four nonsafety-related relays in the ventilation system and that various options were under consideration for permanent resolution of the circuit interface concern. The NRC found the response insufficient to address the inadvertent actuation concern and in a letter, dated June 10, 1997, requested that the permanent resolution address the NRC concerns.

As of the end of the inspection PSE&G had not responded to the June 10, 1997, letter. The inspectors, however, learned that the licensee had designed a modification to be installed during the current refueling outage. This modification, DCP No. 4EC-3644, entailed: (1) the removal of the fire dampers between the standby diesel generator and recirculation system vent rooms; (2) the removal of the fire damper actuation circuitry; (3) the disabling of a portion of the recirculation fan circuitry associated with the fire suppression system; and (4) the addition/removal of appropriate appurtenances. The modification, in essence, expanded the protection zone of the fire suppression system to include the recirculation system vent room, rendering the isolation of the standby diesel generator room in the event of a fire unnecessary.

The inspectors reviewed the modification package, including the safety evaluation and the calculation for required carbon dioxide (CO_2) concentration and concluded that the planned modification was acceptable and would resolve the interaction concerns. A walkdown of the affected areas also indicated that no combustibles existed in the recirculation vent room to increase the probability of a fire in the standby diesel generator room.

Prior to the installation of the modification the licensee decided to perform a CO_2 discharge test to ensure that the diesel rooms would achieve the required CO_2 concentration. Discussions with licensee engineering personnel indicated that a first test conducted in accordance with special test procedure GH.PI-AP.ZZ-0012(Q), "Total Flooding CO_2 System Discharge Test," did not achieve the required concentration (34%) because, shortly after the discharge test was initiated, seals in the CO_2 header isolation valve failed and began to leak CO_2 into the upper chamber of the valve. As a result, the valve began to close. The maximum concentration achieved during this test was 14%. A new isolation valve was installed and plans were made for a second test.

A second test, performed on September 10, 1997, was considered successful by the licensee because a maximum CO_2 concentration of 38% was achieved. However, during the test, the increase in diesel room pressure caused the access door to blow open. Recordings of pressure versus time showed that the pressure had reached approximately 15.1 psia when the door blew open, at which time the pressure dropped instantly to its normal level of 14.7 psig.

Discussions with responsible engineers regarding both events indicated that limited preventive maintenance had been done on the CO_2 system since the initial plant startup and that the discharge test performed at that time might have been done in a cold room. The licensee was investigating the latter event primarily and understood some of the implications of the blown open door, for example the impact of the pressure spike on structures, components, and seals; the ability to prevent a fire from spreading through vents, drains and failed structures; and the maximum attainable pressure in a room with limited air leakage.

Because both discharge tests questioned the licensee's ability to maintain the required CO_2 concentration in the standby diesel generator room, the inspectors also questioned: (1) the ability to suppress a fire in the diesel generator rooms with a failed discharge valve or failed access door; (2) the use of CO_2 in other fire zones; (3) the use of other fire suppression agents; and (4) the impact of incomplete CO_2 system maintenance on the safety systems protected. During the inspection, the CO_2 system was considered inoperable and compensatory measures were in place to address eventual fire suppression needs. According to licensee responsible engineering personnel, these measures will remain in place until the CO_2 system operability is restored.

This item remains open pending completion of appropriate analyses by the licensee and resolution of issues resulting from such analyses.

E8.7 <u>(Closed) URI 50-354/97-01-04</u>: apparent creation of an unreviewed safety question following installation of cross-tie lines between residual heat removal subsystems. This issue was also the subject of LER 50-354/97-05 (see section E8.4 below). A pre-decisional enforcement conference with PSE&G management was held on August 12, 1997, to discuss this issue. As a result of previous inspector reviews of this issue and the information gained at the conference, the NRC concluded that this matter involved a violation of 10 CFR 50.59. A Notice of Violation (VIO E 97-160-01013) was issued under separate correspondence to PSE&G dated October 20, 1997.

E8.8 (Closed) VIO 50-354/97-01-05: reactor core isolation cooling turbine overspeed trip due to governor valve stem binding. This violation involved a repeat failure of the governor valve stem due to corrosion, a well-documented industry issue (PSE&G issued LER 50-354/97-03 which described the details of this event). At the time this violation was issued, all planned corrective actions listed in the noted LER had been implemented and were judged to be acceptable. As such, no response to the violation was required.

E8.9 (Closed) LER 50-354/97-019: closure of SACS to TACS isolation valve. This LER described the inadvertent automatic actuation, on August 7, 1997, of the loop "C" Safety Auxiliaries Cooling System (SACS) in response to a low flow signal from the Turbine Auxiliaries Cooling System (TACS). The signal resulted from the closure of the TACS supply valve. A similar event occurred later on September 4, 1997. In this second event the initiating signal was from a low-low-low SAC expansion tank level alarm.

After the latter event the licensee traced the problem to a loose fuse clip in the Class 1E Analog Bailey Cabinet that provides inputs to the Digital Logic Control System. Although the licensee did not originally identify the initiating cause of the inadvertent engineered safety feature actuation, they were effective in identifying it after the second event, even though the symptoms were different. A root cause analysis was planned to address these failures. Based on their review of PSE&G's corrective actions and confirmation that the licensee had checked for other loose connections in the Bailey cabinets, the inspectors concluded that acceptable actions had been taken to address these issues.

E8.10 (Closed) LER 50-354/97-020: past inoperability of safety-related chillers due to operation with low safety auxiliaries cooling system (SACS) temperature. This issue was described in detail in NRC Inspection Report 50-354/97-05 and was determined to involve a Non-Cited Violation of 10 CFR 50.59. This issue involved a recent self-identified discovery that safety-related chillers would not perform their design function with a loss of instrument air and SACS temperatures below 55 degrees F. Corrective actions described in this LER were judged to be appropriate, in that they focused on the implementation of a hardware design change to eliminate the deficiency. The inspectors learned subsequent to issuance of this LER that PSE&G had developed a modification to add dedicated instrument air accumulators for the safety-related chiller controls such that the impact of a loss of air would be tolerable.

E8.11 (Closed) LER 50-354/97-005: operation in a technical specification prohibited condition due to failure to perform monthly flowpath verification surveillance checks of residual heat removal system cross-tie valves. This issue is also described in section E8.1 above. An additional deficiency identified in this LER involved the discovery that the cross-tie valves had not been previously included in a monthly flowpath verification procedure. The inspectors verified that the associated procedure was revised to include the subject valves. Additionally, PSE&G submitted a TS amendment request to the NRC which would add an additional monthly surveillance requirement to verify that these specific cross-tie valves are locked closed.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 General Observations of Radiological Control Practices

The inspectors observed generally good radiological control practices during the period, which included both operational and shutdown conditions. Radiologically controlled area (RCA) access controls were judged to be effective, largely due to corrective actions instituted following past events. Specifically, ALNOR-activated RCA entry point turnstiles eliminated a past problem involving personnel entering the RCA without proper electronic dosimetry. Radiological Work Permit (RWP) briefings were comprehensive. Technicians frequently questioned workers entering the RCA regarding RWP information to ensure expected dose rates and exposure reduction techniques were understood. The inspectors observed that a thorough pre-job "flush" of the reactor water cleanup system significantly reduced general area dose rates in the vicinity of associated pump work. This effort resulted in the overall exposure received during the activity to be well below job estimates, in spite of the fact that the work continued more than three weeks past the original completion date.

R1.2 Outage RP Performance

a. Inspection Scope (83750)

The inspectors reviewed the licensee's radiological protection program implementation during the Fall 1997 refueling outage. This review consisted of in-plant work observations, interviews with licensee personnel, and review of applicable documents.

b. Observations and Findings

The RP organization expanded staffing with the addition of 63 contractor RP technicians with local control points established for the drywell, refuel floor, torus and the turbine operating floor. The inspector observations of work in progress determined that there were sufficient RP resources available to cover the outage work activities.

On the refueling floor, the inspector observed two sets of racks and a sealant container containing fuel handling poles with approximately 10 wrapped poles that had been opened at the ends exposing the contaminated components. The licensee resealed the wrapped poles.

Inside the torus, diving operations were conducted to clean the underwater surfaces in preparation for emergency core cooling system suction strainer modifications. Surveys indicated 10-30 mrad/hr smearable contamination levels on exposed surfaces next to the catwalk work areas. The diving operation involved equipment contamination at similar levels with RP technicians wiping down the contaminated wet diving equipment as it was removed from the water. Drying out of this equipment and the above water contaminated surfaces provided a potential for airborne radioactivity. The licensee maintained one stationary low volume air sampler at the entry hatch to the torus, which was more than 100 feet from the observed diving and equipment laydown areas. No personal air samples had been taken for at least the previous nine days. This was considered poor air sampling practice. Due to the inherent wet work of the diving operation that tends to reduce airborne radioactivity, and the lack of significant personnel contamination incidents, the safety consequence of the poor air sampling practice was considered low and was therefore viewed as a non-cited violation of 10 CFR 20.1501 pursuant to 20.1204 **(NCV 50-354/97-07-11)**.

Refueling floor activities were regulated by one RWP. This RWP specified electronic dosimeter setpoints of 50 mrem and 100 mrem/hr. During refueling floor evolutions with the cavity flooded, dose rates ranged from <2-5 mrem/hr, with generally less than 10 mrem expected per entry. The drywell inservice inspection weld exam RWP specified electronic dosimeter setpoints of 220 mrem and 500 mrem/hr for all workers. A variety of drywell work area dose rates existed depending on the piping system being inspected. General field dose rates of 20-300 mrem/hr could be expected with similarly varied entry doses.

The licensee made detailed evaluations of snubber locations and weld examination locations to support dose estimates for the outage. These individual location dose estimates were utilized as input to shielding considerations, but were not determined as shielding requirements for the applicable RWPs. There was the potential for work to commence prior to shielding installation.

The inspector's evaluation of the drywell shielding effectiveness indicated a good dose reduction in the basement areas of approximately one-half. The entry level and first level above general radiation fields were not appreciably influenced by the shielding provided, although dose rates were reduced somewhat in the immediate vicinity of the recirculation pump discharge nozzles. Significant dose rate gradients existed in most of the drywell areas.

The inspector observed a weld inspection work station setup in a high dose rate area of the 130-foot elevation of the drywell (70 mrem/hr with adjacent areas 15 mrem/hr) that was not posted.

The 130-foot elevation of the drywell involved safety relief valve replacement activities. The SRVs were in general dose rate fields of between 15-80 mrem/hr within a three foot span. These areas were not posted to allow workers to orient themselves in the lower dose rate fields and to maintain their doses as low as reasonably achievable (ALARA).

The outage RWPs/ALARA reviews did not specify that the planned flushing of reactor vessel nozzles or piping systems or the planned shielding installations were a prerequisite for the applicable work.

c. Conclusions

During the Fall 1997 refueling outage, RWPs generally provided effective contamination control requirements, however, the exposure reduction plans (shielding or pipe flushing) were not specified as job requirements.

Progress in developing and implementing an initial drywell shielding plan was fulfilled during the refueling outage. Some limited drywell shield thicknesses resulted in significant dose rate gradients in many drywell work areas and it was determined that drywell postings were not effective to enable workers to reduce their exposures while working in these high dose gradient areas. With generally high alarm setpoints, the use of electronic dosimeters for exposure control was not optimized.

Some weaknesses in RP controls were observed during the refueling outage that included refueling tool contamination control, and inside torus air sampling practices.

R1.3 Outage ALARA Performance

a. Inspection Scope (83750)

The inspector reviewed the ALARA planning, exposure estimate methods, and interfaces with work management planning, as well as evaluated the results of exposure reduction techniques planned and implemented during the Fall 1997 refueling outage. This review consisted of various documentation, in-plant surveys, and interviews with plant personnel.

b. Observations and Findings

The ALARA group had planned to "hydrolase" the scram discharge volume headers of the control rod drive system to reduce exposures to outage work in these areas. The inspector noted that this exposure reduction work was scheduled to occur after the work on hydraulic control units (HCU) (the principal work affected by the hydrolasing activities) was completed. An interview with the responsible work management planner determined that typical outage windows for system availability delayed the hydrolasing activity until after the HCU work was completed. Detailed review of control rod drive system activities to allow earlier sequencing of the hydrolasing activity had not been adequately performed and some exposure reduction opportunity was lost as a result.

The work order computer database (MMIS - Maintenance Management Information System) contained the preliminary dose estimates. Periodically, the work order information was electronically down-loaded into the scheduling software and allowed the ALARA planning group to determine when the work activity doses were scheduled. For the Fall 1997 outage, the work order dose estimates had been completed, however, the scheduling software indicated almost no dose for the outage tasks up to September 23, 1997 (the outage began on September 10, 1997) with indications that the needed MMIS information had not been down-loaded for many weeks. Therefore, the schedule of work activities could not provide a dose estimate schedule as planned. The ALARA group used the outage schedule and manually developed a dose schedule for each of the eight weeks of the outage. This outage dose schedule assumed the original work schedule would occur as planned. Due to emergent work and material delays, the outage schedule was changed significantly and the RP department could not determine if outage exposure performance was on track or not.

c. Conclusions

ALARA/RP planning activities were not well integrated with work management planning and scheduling and the interface was not always effective. Scheduling of scram discharge volume header flushing activities after the HCU work activities were completed and lack of integration of the outage dose schedule with the outage schedule resulted in less than effective ALARA performance.

R5 Staff Training and Qualification in RP&C

R5.1 RP Technician Training

a. Inspection Scope (83750)

In a previous inspection report (No. 50-354/96-09) it was noted that PSE&G's continuing training program for Radiation Protection (RP) technicians did not provide periodic review of RP fundamentals.

b. Observations and Findings

Subsequent to the October 1996 inspection, the licensee has evaluated RP technician level of knowledge of RP fundamentals by administering the Mid-Atlantic Nuclear Training Group generic examination. For the five subject areas, 77% of the RP technicians received a grade below 80% in one or more subject areas. One-or-one remediation training was conducted to recover the revealed deficient areas. Due to the large percentage of RP technicians that had RP knowledge weaknesses, the RP Services Group was evaluating if other areas of RP performance should be evaluated that are not covered in continuing training, and were determining plans for incorporating RP fundamentals into the continuing training curriculum.

c. Conclusions

The licensee's RP technician continuing training program has been weak as evidenced by poor RP technician performance on an examination given in the Spring of 1997.

R7 Quality Assurance in RP&C Activities

a. Inspection Scope

The inspector reviewed radiological occurrence reports (RORs) initiated since the beginning of the outage.

b. Observations and Findings

During the first 19 days of the Fall 1997 refueling outage, 27 RORs were generated and reviewed by the inspector. They consisted of 18 personnel contamination events, four lost or wrong thermoluminescent dosimeter incidents, three incorrect RCA entries, and two other minor radiological discrepancies. All reports were still open at the time of the inspection and they were under active investigation during the outage.

c. Conclusions

The inspector determined that during the Fall 1997 refueling outage, the RP corrective action program was being actively implemented, with good low threshold and high volume of discrepancies being reported.

R8 Miscellaneous RP&C Issues

R8.1 (Closed) URI 50-354/97-03-02: lack of timely completion of a design change package for meteorological monitoring instrumentation. This issue, which questioned the process for maintaining configuration control of plant equipment, was identified during an NRC inspection of the radiological effluents monitoring program. The inspectors subsequently concluded that this issue involved an isolated failure to implement the requirements of PSE&G's design change process. Additionally, because the meteorological monitoring system is not within the scope of 10 CFR 50 Appendix B regarding quality assurance criteria, the lack of timely implementation of this change package did not constitute a violation of regulatory requirements.

R8.2 (Open/Closed) VIO 50-354/97-07-12: violation of the new Department of Transportation (DOT) shipping paper requirements. In a previous inspection report (No. 50-354/97-04), a violation of the new DOT shipping paper requirements was identified. Specifically, radioactive laundry shipping papers did not indicate the appropriate low specific activity (LSA) group notation from April 1, 1996 through June 9, 1997 as required by 49 CFR 172.203(d)(11). Hope Creek and Salem stations ship laundry separate from each other and, therefore, a violation was issued to each station.

During this inspection, the inspector reviewed procedure, NC.RP-RW.ZZ-0906(Q), Rev. 2, "Shipment of Radioactive Material", and verified that the LSA group designations were specified in the procedure. The inspector also verified that Hope Creek radioactive laundry shipment no. 97-27 was shipped as LSA-II as required.

P1 Conduct of EP Activities

P1.1 Unannounced Emergency Preparedness Drill

PSE&G conducted an unannounced off-hours drill of all emergency response facilities on August 27, 1997. The inspectors observed the drill from the technical support center (TSC), and noted generally good implementation of Hope Creek emergency plan requirements. Appropriate procedures were used, good communications were established, and a proper turnover from the senior nuclear shift supervisor was completed. One notable issue involved the failure to staff the TSC in a timely manner (i.e. 29 minutes late). The post-drill critique was thorough and captured this issue and all other relevant concerns.

P8 Miscellaneous EP Issues

P8.1 (Closed) URI 50-354/96-07-03: UFSAR discrepancies regarding PSE&G emergency plan. NRC inspectors identified two issues during a 1996 program review: (1) no radiological instrumentation was available in the training center laboratory for use as a backup as stated in the emergency plan, and (2) PSE&G was not conducting an annual program to provide emergency response information to the media and public as described in the emergency plan. The inspectors verified that both of these discrepancies have since been resolved. In the first case, PSE&G eliminated the statements describing backup instrumentation from the emergency plan because the training center laboratory has been dismantled. In the latter case, the emergency plan was revised to clarify how the emergency response information could be disseminated. PSE&G can now take credit for media participation in annual emergency preparedness drills or exercises.

V. Management Meetings

X1 Exit Meeting Summary

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR descriptions. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters.

The inspectors presented the inspection results to members of licensee management on October 10, 1997. Licensee personnel acknowledged the findings presented. However, on September 30, 1997, where the engineering inspection findings were presented, the licensee disagreed with the inspectors' conclusions regarding the relays located in a mild environment, stating that an adequate relay monitoring program existed.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

INSPECTION PROCEDURES USED

IP 37550:	Engineering
IP 37551:	Onsite Engineering
IP 50090:	Spent Fuel Storage Racks
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 73052:	Inservice Inspection - Review of Procedures
IP 73753:	Inservice Inspection
IP 83750:	Occupational Radiation Exposure
IP 90712:	Event Report Review
IP 92902:	Followup - Maintenance

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-354/97-07-01	VIO	lack of timely identification of inoperable electric fire water pump.
50-354/97-07-02	URI	degraded reactor coolant system pressure boundary.
50-354/97-07-03	VIO	failure to adhere to maintenance procedures.
50-354/97-07-04	VIO	failure to perform a safety evaluation per 10 CFR 50.59
50-354/97-07-05	URI	service life of mild environment Struthers-Dunn relays
50-354/97-07-06	VIO	failure to include five relays in 10 CFR 50.49 program
50-354/97-07-07	VIO	failure to perform adequate relay service life calculations
50-354/97-07-08	URI	service life of Agastat relays in harsh environments
50-354/97-07-09	URI	circuit breaker failure analysis

Opened/Closed

50-354/97-07-10	NCV	failure to report violation of license condition
50-354/97-07-11	NCV	poor air sampling practice
50-354/97-07-12	VIO	failure to include current LSA group specification (LSA-I,II,or II) on laundry shipping papers since April 1, 1996.

Closed

50-354/96-04-01	VIO	failure to account for Bailey SSLM failures
50-354/96-04-02	URI	control of Bailey logic tester programs
50-354/96-04-03	IFI	Bailey SSLM EMI circuit testing
50-354/96-04-04	IFI	UFSAR discrepancies
50-354/96-07-03	URI	UFSAR discrepancies regarding PSE&G emergency plan
50-354/96-11-01	DEV	failure to revise TS bases as committed in a PSE&G license amendment

50-354/EA 96-014-01013	VIO	repeat failure of RHR system shutdown cooling common suction line mechanical snubber
50-354/97-01-04	URI	apparent creation of a USQ following installation of cross-tie lines between RHR subsystems
50-354/97-01-05	VIO	RCIC turbine overspeed trip due to governor valve stem binding
50-354/97-02-01	VIO	failure to shut EDG cylinder test cocks prior to engine operation
50-354/97-03-02	URI	lack of timely completion of a design change package for meteorological monitoring instrumentation
50-354/97-005	LER	operation in a TS prohibited condition
50-354/97-018	LER	ESF actuations as a result of RPS motor generator set output breaker trip
50-354/97-019	LER	SACS to TACS isolation valve closure
50-354/97-020	LER	past inoperability of the safety-related chillers due to operation with low SACS
50-354/97-021	LER	standby liquid control system tank concentration below TS limits
50-354/97-022	LER	engineered safety feature actuation - unplanned manual scram

Discussed:

50-354/96-09-03	VIO	interaction of safety and non-safety related components in the EDG room ventilation system

LIST OF ACRONYMS USED

AE	Architect-Engineer
ALARA	As Low As is Reasonably Achievable
ANI	Authorized Nuclear Inspector
ASME	American Society of Mechanical Engineers
DOT	U.S. Department of Transportation
EDG	Emergency Diesel Generator
EESS	Equipment Evaluation Summary Sheet
EO	Equipment Operator
EMI	Electro-Magnetic Interference
F&H	Farwell & Hendricks
GE	General Electric
HCGS	Hope Creek Generating Station
HCU	Hydraulic Control Unit
HPCI	High Pressure Coolant Injection
IGSCC	Intragranular Stress Corrosion Cracking
IRM	Intermediate Range Neutron Monitor
ISI	Inservice Inspection
LSA	Low Specific Activity
MMIS	Maintenance Management Information System
NDE	Nondestructive Examinations
NRC	Nuclear Regulatory Commission
PDR	Public Document Room
PSE&G	Public Service Electric and Gas
PT	Penetrant Test
QA	Quality Assurance
RCA	Radiologically Controlled Area
RCIC	Reactor Core Isolation Cooling
RORs	Radiological Occurrence Reports
RP	Radiation protection
RP&C	Radiological Protection & Chemistry Controls
RPS	Reactor Protection System
RWPs	Radiation work permits
SACS	Safety Auxiliaries Cooling System
SER	Safety Evaluation Report
SLC	Standby Liquid Control
SORC	Station Operations Review Committee
SSLM	Solid State Logic Module
TS	Technical Specifications
TSC	Technical Support Center
UFSAR	Updated Final Safety Analysis Report
UT	Ultrasonic Test