U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report Number: 95-15

Docket No.: 50-443

License No.: NPF-86

Licensee: North Atlantic Energy Service Corporation
Post Office Box 300
Seabrook, New Hampshire 03874

Facility: Seabrook Station

Dates: November 14, 1995 - December 31, 1995

Inspectors: John B. Macdonald, Senior Resident Inspector
David J. Mannai, Resident Inspector

Approved By: John Rogge, Chief — 2/7/96 Date
Division of Reactor Projects, Branch 8

Inspection Summary: Inspections were conducted during normal and backshift hours in the areas of plant operations, maintenance, engineering, and plant support.

Routine inspections included refueling machine surveillance. Initiative inspections included inspector review and observation of refueling, mid-loop/reduced inventory operations, and engineering backlog. Reactive inspections included Primary Component Cooling Water (PCCW) Heat exchanger tube degradation and the work control breakdown during SG maintenance and sludge lancing activities.

Results: The results of the inspection are summarized in the Executive Summary.

EXECUTIVE SUMMARY

SEABROOK STATION
NRC INSPECTION REPORT NO. 50-443/95-15

Plant Operations: Mid-loop operations were safely performed during the refueling outage. Strong oversight and control of the activity was observed. Involved personnel maintained excellent monitoring and awareness of plant parameters. Operator response to the unexpected pressurizer surge line filling during reactor coolant system evacuation was good.

Refueling operations were accomplished effectively. Good command and control was evident. Oversight and control of contractors performing fuel movements were good.

Maintenance/Surveillance: Operations department personnel completed refueling machine surveillance activities adequately. The inspector observed that in response to unexpected indications, involved personnel marked the step not applicable, but did not issue procedure changes prior to completing the evolution. The inspector considered this inconsistent with station guidance and management expectations.

Overall maintenance during the outage was performed safely and effectively with good supervisory oversight. Management involvement was evident. However there were several instances of ineffective maintenance performance on safety-related equipment. The problems encountered were promptly documented and entered in the adverse condition report process. The repeat problem of working on the wrong train of primary component cooling water indicated a weakness regarding the corrective action process. Although the actual safety significance was minimal the potential for more serious consequences existed.

Engineering: The identification and interim resolution of the unexpected primary component cooling water (PCCW) heat exchanger tube degradation demonstrated good problem identification/resolution from an engineering perspective. The initial engineering response appeared to lack focus. Following senior management involvement, the licensee's problem analysis focused on fully understanding the cause of the degradation and the emphasis for corrective action became more lasting and comprehensive.

The inspector reviewed the engineering backlog and determined the licensee effectively manages the backlog. The backlog is periodically reviewed with proper management oversight to ensure proper closeout of outstanding items. Some temporary modifications were noted to be longstanding.

Licensee engineering and design change review efforts to address two unresolved items with licensing and design-basis impact were found to be technically adequate, using appropriately-conservative assumptions. In the case involving the main steam safety valve setpoints, an error in the technical specifications (TS) has been corrected; however, the process of arriving at the proper setpoint values was somewhat protracted. This resulted in a TS clarification providing nonconservative guidance for some period of time, although no associated plant safety challenges were experienced over

this time period. The licensee's control, quality assurance, and oversight of the steam generator eddy current testing and inservice inspection programs were in strong evidence. The results of these inspection processes were also consistent with the plant design. These results confirmed general compliance with code requirements and provided additional data to address recent regulatory concerns (e.g., Generic Letter 95-03) regarding safety component wear and serviceability.

Plant Support: Overall, performance in the radiation protection area was considered to be very good. No problems of regulatory significance concerning the radiation protection program were noted. Licensee radiation protection, engineering, and operations staff promptly and effectively responded to the unexpected emergence of a 500 Rad/hr hotspot during cavity drain down, and demonstrated good application of radiation protection to control and mitigate the potential radiological hazard. The newly-installed alarming dosimeter and radiologically-controlled area access control system was an improvement to the radiation protection program in that it significantly enhanced the licensee's ability to effectively monitor and control personnel exposures. Additionally, the licensee's extensive use of teledosimetry to better effect real-time occupational exposure control for high exposure jobs demonstrates a commitment to improve the efficiency and quality of radiation protection activities.

Security Plan requirements were maintained throughout the refueling outage. The security force effectively compensated for systems and components required to be degraded to support other outage related activities.

Safety Assessment/Quality Verification: Good management oversight and safety perspectives were apparent in the development of the outage schedule with respect to shutdown risk minimization and in the outage organization with the respect to the evaluation and resolution of emergent issues. Clearly outage safety was maintained as the primary objective throughout all refueling activities. Particularly noteworthy were the preparation for and actual operation with the reactor coolant system inventory reduced to the mid-loop level to support steam generator inspection activities.

TABLE OF CONTENTS

DETAILS

1.0 Summary of Facility Activities

At the start of the report period, the reactor was in Mode 6 in Day 11 of the refueling outage. Core offload commenced on November 16 and the reactor was in a defueled condition on November 20 (Section 2.2). On November 20, reactor coolant system (RCS) inventory was reduced to install steam generator nozzle dams (Section 2.3). On November 23, the reactor entered Mode 6 when operators began loading fuel back into the reactor (Section 2.4). Core reload was completed on November 26. On December 1, RCS inventory was again reduced, this time with fuel in the reactor vessel for SG nozzle dam removal (Section 2.3). The reactor entered Mode 5 when the last reactor vessel head stud was tensioned on December 30. The plant was heated up and Mode 4 was reached on December 6. Mode 3 was attained on December 7. Reactor startup commenced and Mode 2 was reached on December 9. Low Power Physics Testing was completed on December 10. Power was increased and Mode 1 was reached on December 10. The generator was synchronized to the grid at 1:03 p.m. on December 11, ending the refueling outage. Power ascension testing was completed and the reactor reached 100% of rated thermal power on December 16 and was maintained through the end of the inspection report period.

2.0 PLANT OPERATIONS (71707,71750,92901,93702)

2.1 Plant Operations Review

The inspector observed the safe conduct of plant operations (during regular and backshift hours) in the following areas:

Control Room	Fence Line (Protected Area)
Primary Auxiliary Building	Residual Heat Removal Vaults
Diesel Generator Building	Turbine Building
Switchgear Rooms	Intake Structure
Security Facilities	

Plant housekeeping, including the control of flammable and other hazardous materials, was observed. During plant tours, logs and records were reviewed to ensure compliance with station procedures, to determine if entries were correctly made, and to verify correct communication of equipment status. These records included various operating logs, turnover sheets, tagout, and lifted lead and jumper logs.

Control room instruments were independently observed by NRC inspectors and found to be in correlation amongst channels, properly functioning and in conformance with Technical Specifications. Alarms received in the control room were reviewed and discussed with the operators; operators were found cognizant of control board and plant conditions. Control room and shift manning were in accordance with Technical Specification requirements. Posting and control of radiation, high radiation, and contamination areas were appropriate. Workers complied with radiation work permits and appropriately used required personnel monitoring devices.

2.2 Core Refueling Process

The inspector reviewed the licensee fuel movement strategies to be used during the refueling outage. The licensee employs a full core off-load practice as the initial phase of a routine refueling evolution. The inspector reviewed Updated Final Safety Analysis Report (UFSAR) Section 9.1.3, "Spent Fuel Pool Cooling and Cleanup Systems,"and noted that performance of full core off-loads, as a routine, during normal refueling operations is described in the design bases of the fuel pool cooling system. The full core off-load facilitates safety train outages, reduces shutdown risk analysis while at reduced reactor coolant system inventory associated with mid-loop operations and is an efficient fuel shuffle option that minimizes fuel manipulations. The UFSAR was updated by USFAR Change Request 94-008 to reflect the full core off-load practice. The change additionally included a commitment to evaluate, prior to each refueling outage, the capability of the spent fuel pool cooling system to remove the decay heat associated with previously discharged fuel assemblies in addition to the full core off-load. The purpose of the evaluation is to ensure that (1) the spent fuel temperature will remain below 141 degrees Farhienhiet (°F) during the full core off-load period with the Atlantic Ocean available as the normal ultimate heat sink, considering one train of normal cooling and one spent fuel pump are in operation, and (2) that the spent fuel pool temperature will not exceed 140°F for the abnormal case of the cooling tower functioning as the ultimate heat sink (due to circulating water tunnel blockage of greater than 95%) if two spent fuel pool cooling trains are available.

The inspector reviewed Engineering Evaluation 95-18, "Spent Fuel Pool Cooling Evaluation For RF04," dated July 13, 1995. The evaluation assessed best estimate refueling heat loads associated with the full core off-load assuming the off-load would be completed 11 plus days after reactor shutdown. Additionally, the evaluation assumed the design basis ocean water temperature of 65°F and ambient wet bulb temperature of 75°F. The inspector also reviewed the spent fuel pool heat exchanger performance evaluation, SBC-627, that had been previously performed in support of the third refueling outage.

The calculations and evaluations used appropriate design bases parameters described in the UFSAR as well as the methodologies and guidelines provided in NRC NUREG-0800, "Standard Review Plan," and NRC Branch Technical Position, "ASB 9-2 Residual Decay Energy for Light Water Reactors for Long Term Cooling."

The inspector reviewed the requirements of Technical Specification (TS) 5.6 regarding the design features for fuel storage. TS 5.6.1.1 requires that the spent fuel storage racks be designed and maintained such that the spent fuel criticality (K eff) be equivalent to less than or equal to 0.95 when flooded with unborated water and with a nominal 10.35 inch center to center distance between fuel assemblies when fully inserted into the storage racks. TS 3.9.13, requires that fuel assemblies be stored in the spent fuel pool in accordance with the criteria of TS Figure 3.9-1, which establishes allowable storage locations based upon fuel assembly burn-up versus initial enrichment, such that three types or storage classifications of fuel assemblies are

established to ensure spent fuel pool subcriticality is maintained at all times. The assignment of specific spent fuel pool storage locations for fuel assemblies based upon burn-up and initial enrichment is referred to by the licensee as "checkerboarding." Previously, in NRC Inspection Report No. 50-443/95-11, Section 4.8, the inspector reviewed the checkerboarding process with respect to the generic concerns for the degradation of the Boraflex neutron absorber in spent fuel racks. Finally, the inspector reviewed the TS BASIS B3/4.9.13, regarding spent fuel assembly storage. The inspector identified an apparent typographical error in the BASIS statement. Specifically, the BASIS stated that restrictions on the placement of fuel assemblies of certain enrichments (ie, checkerboarding) will ensure that the K eff of the spent fuel pool will always remain less than 0.98 vice the correct value of 0.95. The inspector reviewed the NRC Safety Evaluation Report for Amendment No. 6 to the Seabrook Station Operating License and verified that the TS BASIS discrepancy was in fact a typographical error. The inspector brought this observation to the attention of reactor engineering management who in turn initiated action to correct the error.

In conclusion, the licensee properly revised affected UFSAR and TS sections to reflect the conduct of full core off-loads as a routine refueling outage activity. Associated evaluations of the spent fuel pool cooling system were performed consistent with NRC endorsed guidance and appropriate controls were established to ensure fuel assemblies were positioned in the assigned spent fuel pool rack locations. The inspector had no questions regarding this activity.

2.3 Mid-loop Operations

The reactor coolant system (RCS) was operated at reduced water levels on two occasions during the refueling outage to support steam generator inspection activities. The first mid-loop operations evolution was performed in accordance with OS 1000.12, "Operation with RCS at Reduced Inventory/Mid-loop." Operations at reduced inventory were required to install Steam Generator (SG) nozzle dams to allow SG eddy current testing, which was done with core fully offloaded. The second mid-loop operations evolution, conducted with fuel in the reactor vessel core, was performed to remove the SG nozzle dams, using procedure OS 1000.14, "RCS Evacuation and Fill." The inspector reviewed the procedures, observed evolution briefings, witnessed procedure performance, walked down test equipment inside containment, and confirmed level measurement and vent pathways.

The inspector noted good coordination and communication during the activity. Involved personnel were knowledgeable of the procedure, plant conditions and procedure termination criteria. Complex evolution administrative requirements were met. RCS level measurement methods were understood by operators and the inspector verified indicated level tracked within the requirements of the procedure. Proper residual heat removal (RHR) system operation was verified. Prior to the mid-loop operations, the inspector identified inadequate temporary level indication tygon hose routing and difficult to read level measurement markings inside containment. The licensee promptly corrected the conditions. The inspector confirmed the licensee incorporated appropriate generic NRC information and lessons learned in the development of the

procedure and performance of mid-loop operations. The licensee experienced some difficulty when performing the evacuated fill of the RCS following removal of the SG nozzle dams. During the evacuation of air, prior to fill, unexpected filling of the pressurizer surge line began to occur. Operators and test personnel quickly realized this and terminated the evacuation, broke vacuum and increased charging system flow. RCS level indications stabilized (-75 inches) and involved personnel evaluated the condition. The surge line filling occurred because the RCS level had not been reduced sufficiently to optimize communication between the pressurizer and the rest of the RCS. When developing the procedure the licensee did not account for the wall thickness of the pressurizer surge line piping and the target level specified in the procedure of - 77 inches (- 73.5 inches to - 81.5 inches level band) was not adequate for evacuation. The surge line enters the side of the RCS piping and the licensee subsequently determined that at - 81 inches, a small air gap exists to allow air communication between the RCS and pressurizer. Initial RCS level at the start of evacuation was - 77 inches. RCS level was lowered sufficiently (- 81 inches) to allow communication between the pressurizer and the rest of the RCS. The evacuation and fill were then satisfactorily performed. However, venting of the RCS took significantly longer than expected due to the effervescing that occurred on initial RCS evacuation. The licensee gathered feedback from personnel involved to develop lessons learned and incorporate improvements and enhancements for future performance of the procedure.

The licensee performed mid-loop operations safely and effectively with good management oversight and involvement. The decision by station management to perform the first mid-loop operation with the fuel offloaded demonstrated a strong safety perspective. Operators maintained excellent focus regarding RCS inventory and decay heat removal throughout mid-loop operations. The test director coordinated the activity well, ensuring all involved personnel understood their responsibilities. The inspector observed excellent monitoring and awareness of key plant parameters during operations with reduced inventory. Personnel implemented procedure changes, where necessary, in process. Good awareness and control of plant activities which could affect the RCS during reduced inventory were maintained. Operator response to the unexpected surge line filling during RCS evacuation was good. However, the inspector considered the licensee could have identified the appropriate target level for evacuation during the development of the procedure. The inspector had no further questions.

2.4 Refueling Operations

The inspector observed refueling operations on November 24. Refueling personnel loaded fuel into the core from the spent fuel pool. The licensee used contractors to perform the fuel movements. Licensed senior reactor operators (SRO) from the Seabrook Station Training Department provided oversight required by regulations and plant technical specifications. The activity was performed using operating procedures OS 1015.04, "Refueling Machine Operation" and OS 1000.09,"Refueling Operation." The inspector held discussions with refueling personnel, reviewed the operating procedure, and independently verified selected fuel assemblies for proper identification and core location.

Overall, the inspector confirmed the activity was performed in a controlled and deliberate manner. The refueling SRO provided good oversight and direction during the evolution. The inspector verified that command and control responsibilities for fuel movement were clearly delineated and understood. Continuous communications were maintained during movement of irradiated fuel, as required by plant technical specifications. Other applicable refueling technical specifications were reviewed and confirmed for proper compliance. The inspector identified that operators were using information written on masking tape affixed to the control console of the refueling machine during refueling operations. The information pertained to relative height of the refueling mast at specific locations as well as other pertinent information. The inspector considered this information, while useful, was uncontrolled and constituted an unauthorized operator aid. The situation was discussed with the refueling SRO and Operations Department management. The licensee promptly issued the information in the form of an approved operator aid in accordance with Operations Management Manual (OPMM), Chapter 8.0, "Control Of Operator Aids." The use of an unauthorized operator aid had no adverse impact and was considered a minor weakness. The inspector observed one instance where the spotter had to intervene to avoid potential undesired contact between a fuel assembly that was being lowered into the core and adjacent fuel assemblies. The assembly was being lowered "off index" when it should have been "on index." The inspector found that while the defense-in-depth provided by the spotter prevented a problem, the situation could have been avoided by better communications and awareness by the personnel involved. The inspector had no further questions.

3.0 MAINTENANCE (61726,62703,92902)

3.1 Refueling Machine Surveillance

On November 14, the inspector observed performance of IX 1641.903, "Pre-operational Checks Of Refueling Machine (RTS 95RI006056002)," Section 4.11, regarding the mast load test. The inspector held discussions with involved operations personnel, reviewed the procedure, observed procedure implementation and independently verified acceptance criteria were met. Overall, the activity was safely and effectively performed by operators. Technical Specification (TS) surveillance acceptance criteria were satisfactorily met. One difficulty involved an instance where the procedure required the verification that the "HOIST IS SLIPPING" was displayed on the refueling console CRT and unexpectedly the display was not obtained. Instrumentation and Control (I&C) personnel were consulted and determined the unexpected condition was technically explainable and acceptable to proceed. This was annotated in the procedure, however, a procedure change was not issued. The inspector questioned the involved operators if this was an acceptable way of conforming to station procedural adherence guidance. It was not clear to the inspector that involved personnel had a good understanding whether it was appropriate and what specific procedure adherence guidance supported their interpretation. The inspector considered this an example of procedure performance which was inconsistent with written station guidance and management expectations. The inspector held discussions with appropriate station management and determined that the present procedure adherence

guidance and expectations are being evaluated. The inspector will continue to assess licensee performance in this area.

3.2 Refueling Outage Maintenance Performance

During the refueling outage, the licensee performed numerous maintenance and modification activities safely and effectively, using approved station procedures and work plans with good supervisory and management oversight. Several major modifications were implemented. However, there were some notable exceptions that were identified by the licensee or were self-disclosing. The problems were documented in the Adverse Condition Report process. Some examples are detailed below.

The licensee narrowly missed draining the secondary side of the "A" Steam Generator (SG) inside containment. During a routine schedule review, outage management identified a conflict between ongoing sludge lancing activities and repair activities on SG blowdown valve SB-V-189, which has no isolation from the SG. All but four bolts were removed from the valve. Contract personnel performing the work were experiencing difficulty disassembling valve, due to previous leak sealant injection. The crew which had begun to loosen the remaining four body-to-bonnet fasteners, were notified immediately to stop work. Previously, operations had drained down the "A" SG and a master tagout had been hung and various work activities released. Sludge lancing activities required removal of the SG manway and filling of the SG from an external water supply controlled by a vendor. Control room operators were aware of the status of filling the SG from an external source. The tagout for the SB-V-189 work did not preclude filling of the secondary side of the SG through the manway.

The licensee documented the problem on ACR 95-428 and formed an event evaluation team to evaluate the work control breakdown. The licensee implemented several immediate corrective actions which required supervisors to perform energy checks prior to system breach. The inspector reviewed the event evaluation which identified work planning, work control and configuration control program vulnerabilities. The evaluation was detailed and thorough, the root cause and associated corrective actions appeared adequate, comprehensive and aimed at preventing recurrence. The decision to form an event evaluation team was good.

Additionally, on two separate occasions, maintenance was initiated on the wrong train of the PCCW system. The work involved temperature control valves (TCV) on the PCCW heat exchangers. The first instance occurred when work was performed on the protected train "B" temperature control valve (1-CC-TCV-2271-1), when the work request authorized work on train "A" temperature control valve (1-CC-TCV-2171-1). The work consisted of inspecting and lubricating the manual operators for 1-CC-TCV-2171-1 and 1-CC-TCV-2171-2. During the shift, work was incorrectly performed on 1-CC-TCV-2271-1. Work continued through the shift and was turned over to second shift. The second shift personnel realized work was performed on the wrong train. The licensee documented the problem on ACR 95-379 and took immediate corrective action which included determining the work had no effect on operability since only local manual operation was affected. The licensee determined the train was still operable.

Interim corrective action consisted of reassembling the valve and holdings meetings with maintenance personnel. Prior to the ACR evaluation being completed the event recurred approximately two weeks later when the TCV valve on the protected train was again worked. This time the maintenance required removal of limits switches to facilitate packing removal. A supervisor questioned technicians if they were on the correct valve, the involved technicians checked and realized they were on the wrong valve. The licensee documented and evaluated the event on ACR 95-449. The licensee determined the primary causes were less than adequate self checking and the pre-job brief did not include a review of the first event. The ACR evaluation identified ineffective interim corrective actions as a contributing cause. The individuals involved in the second event were not aware of the previous occurrence nor did they receive a briefing on the first event. The evaluation also concluded there were no interim actions to adequately label the valves. A corrective action from the first event was to human factor and relabel the PCCW TCV valves by February 1, 1996. The inspector considered the licensee evaluation for the second occurrence appropriately critical.

The inspector noted the licensee documented several other maintenance performance problems in the ACRs process. Examples included wiring combustible gas control system valve CGC-V-28 motor operated actuator backwards, which was identified during retest, and installing the thrust bearing backwards on the turbine driven emergency feed water (EFW) pump, which was identified by another mechanic in process.

The inspector noted in the examples outlined and others that were reviewed, that the licensee documented the problems promptly on ACRs. In some cases, personnel identified the problem using a questioning attitude, in others the problems were self-disclosing. The event evaluation on the SG drain down "near miss" was an excellent example of a thorough and comprehensive ACR evaluation. The safety significance was minimal since the problems were identified in process or during retest prior to the equipment being declared operable. However collectively, the examples indicated weaknesses in the implementation of maintenance on safety related equipment. Causes identified included less than adequate self-checking, inadequate procedural guidance, failed second person verifications. The performance also indicated weaknesses regarding effectiveness of corrective actions, particularly interim corrective actions. The licensee, in response to the maintenance performance errors, is performing an integrated assessment of the performance issues. A strong emphasis will be on understanding the human performance aspects of these events. The inspector expressed concern to Maintenance Department management since performance in these examples contrasted sharply with the licensee's strong emphasis on performing maintenance correctly the first time while adhering to the station procedures, using self-checking practices and additional supervisory oversight. The inspector considered the licensee integrated assessment initiative prudent. Additionally, the licensee outage critique process is expected to address the outage related aspects of the performance issues. The inspector will review the results of the licensee's assessment.

3.3 Broken Diesel Generator Fuel Injection Pump Delivery Valve Springs

During the refueling outage, the licensee conducted the 18 month emergency diesel generator (EDG) inspection and overhaul. During inspection of the "A" EDG, mechanics identified that six of the 16 fuel delivery valve springs were broken in the fuel delivery valve assemblies. Adverse Condition Report, ACR 95-382, was generated to document this condition and all 16 springs were replaced in kind. Additionally, a sample of springs was sent to an offsite independent metallurgical laboratory for material property analysis. Historically, the licensee had identified 12 broken springs on six different occasions on both EDGs prior to the current inspections (NRC Inspection Report Nos. 50-443/92-27 & 93-02).

Colt-Pielstick Model PC 2.5 EDGs are installed at Seabrook. The fuel delivery valve functions (closes) at the conclusion of the fuel injection stroke to ensure the fuel injector nozzle remains liquid filled, at a pressure greater than the fuel vaporization point. This design enhances fuel injector performance by minimizing cavitation at the injector nozzle. Colt Industries engineers indicated to the licensee that the failure of delivery valve springs would not affect the operability of the EDGs and that the most noticeable effects would be potentially increased exhaust gas temperatures and cavitation induced long term erosion and degradation of the high pressure fuel lines. The licensee performed an operability determination (EEN 95-35) for the "A" EDG with the original delivery valves installed that concluded the failure of valve springs would not effect the operability of the EGD. Due to the historical nature of the spring failures, the licensee had developed a modification, MMOD 95-595, that would replace the EDG fuel delivery valve spring assembly with a new design that includes a spring of increased metallurgical properties. The modification was installed on the "B" EDG during the ORO 4. The valve assemblies will be replaced on the "A" EDG in ORO 5 during fuel injector pump refurbishment.

The inspector observed portions of the EDG overhaul and inspections. The inspector also reviewed the EDG fuel oil system design, maintenance history, and current evaluations. Additionally, the inspector attended the Station Operations Review Committee during which the operability evaluation was reviewed. The inspector concluded the licensee effectively identified and evaluated the spring failures. The inspector had no further concerns.

4.0 ENGINEERING (71707,37551,92903,40500)

4.1 Primary Component Cooling Water Heat Exchanger Inspections

During the outage, the licensee performed planned inspections and eddy current testing (ECT) of the "B" primary component cooling water (PCCW) heat exchanger due to previous heat exchanger tube degradation. ECT and inspection indicated tubing (90-10 copper-nickel tube material) degradation, which was unexpected since both PCCW heat exchangers were retubed last outage, in addition to several other measures taken to correct excessive tube degradation. The degradation consisted of localized wall thickness reduction. NRC Inspection Report No. 50-443/94-08 documented a detailed review of the tubing degradation found and associated corrective measures taken in refueling outage ORO3.

During unrelated service water (SW) system work, a quantity of iron shot was found in the piping between the SW discharge strainer and the B PCCW heat exchanger. The material was sent to an offsite laboratory for analysis. Due to the unexpected tube degradation, the licensee documented the problem on adverse condition report ACR 95-440.

The licensee reviewed the history for the PCCW Heat exchangers with particular focus on the root cause determination and corrective actions associated with the tube degradation found during refueling outage OR03. An action plan was developed which included heat exchanger tube inside diameter cleaning, plugging of tubes with greater than 40% wall loss, eddy current testing of the "A" PCCW heat exchanger, determining source of iron deposits, performing an internal inspection of service water piping and installation of improved SW strainer design. The licensee pulled some tubes from the heat exchanger and sent them offsite to independent test laboratories for analysis. Several contracted technical consultants evaluated the tube degradation, inspection results and materials analysis. The ferrous material found in the system was determined to be residual iron shot material used in the 1986 time frame for surface preparation prior to applying Belzona. High levels of iron were found in the tubing deposit samples during OR03, however the source of the iron was never determined.

A total of 8 tubes were plugged in the "B" PCCW HX. ECT was performed on 40% of the "A" PCCW HX, with acceptable test results. The internal SW pipe inspections did not locate any similar iron shot or material. The extent of the degradation, although unexpected, was not considered significant by the licensee. Materials analysis showed the presence of iron in scale deposit and sludge samples. The licensee determined that an inadequate passivation layer was formed following tube replacement due to less than optimum ocean temperature. Operation in cold sea water temperatures much less than 70°F resulted in the slow formation the protective copper oxide film which provides Cu-Ni with its corrosion resistance in sea water. The licensee identified the PCCW heat exchanger tube degradation mechanism as flowing debris initiating local, general corrosion sites with lack of adequate time to perform a mature passivation layer as a contributing cause. The licensee prepared a written operability determination for the PCCW tube degradation that supported plant startup.

The inspector attended senior licensee management briefings on the issue, held discussions with Engineering and Technical support personnel, reviewed tube inspection results, materials analysis results, draft completed ACR evaluation and associated operability determination. The initial engineering response to the issue appeared to lack formal direction and focus. Senior management involvement ultimately ensured adequate focus and direction to the resolution. The decision to perform ECT on the "A" PCCW heat exchanger was prudent given the unexpected degradation of the "B" PCCW heat exchanger tubes. The inspector found the licensee interim resolution to the PCCW tube degradation issue adequate. The operability determination adequately documented the basis for operability. The determination conservatively bounded operability throughout the next operating cycle for the corrosion mechanism observed using reasonable assumptions for the corrosion rate. The formal operability determination was issued prior to plant startup. The draft ACR evaluation,

which had not yet been reviewed by the Occurrence Review Committee, did not evaluate the effectiveness of previous corrective actions. Specifically, the previous corrective actions taken for tube degradation were potentially less than fully effective since the extent of tube degradation was unexpected. The initial response by Engineering did not address this aspect. The OR03 evaluation did not identify the source of the iron found during the outage nor were the less than optimum passivation layer formation conditions identified. The inspector considered this represented a missed opportunity for Engineering to critically self assess the previous engineering resolution to tube degradation issue and identify opportunities for improvement in resolving complex technical issues. The NRC will review and assess the licensee's final ACR evaluation and the long term planned resolution of the PCCW heat exchanger tube degradation issue.

4.2 Engineering Backlog

During the period, the inspector reviewed the engineering backlog to determine if the backlog was properly prioritized and effectively managed. Discussions were held with appropriate Engineering and Technical Support personnel. The inspector reviewed the engineering backlog. The backlog consisted of Request for Engineering Services (RES), Design Change Requests (DCRs), Minor Modifications (MMODs), Request for Engineering Services (RES), Engineering Self Assessments (ESARs) and temporary modifications (TMODS). Adverse Condition Reports (ACRs) assigned to Engineering for resolution are controlled and tracked separately under the ACR process for backlog. The various mechanisms are tracked and items outstanding are specified as backlog.

The process typically begins with identifying the issue for resolution in an RES. The RES is reviewed by engineering management who determines priority. An RES is given a priority 1,2 or 3. Priority 1 requires evaluation within seven working days, priority 2 within 90 days and priority 3 is not specified. Once evaluated, the RES typically results in a written evaluation to close the issue, or becomes a proposed MMOD or DCR. The DCRs and MMODs are presented to the Station Modification Resource Committee (SMRC) at which time the DCR or MMOD is approved, prioritized (SMRC ranking) and scheduled for implementation. Implementation is typically scheduled for the present business cycle, next refueling outage or the next business cycle. In some cases the implementation is scheduled later due to resource considerations. The outstanding items that are scheduled for implementation are reviewed routinely in the weekly planning and scheduling look ahead meeting. Additionally an annual prioritization review is performed for the engineering backlog. The ESAR is a process which is used to address concerns below the threshold requirement for initiating a corrective action document.

The RES backlog consisted of approximately 300 items, the majority of which are priority 3. Of the 300 RESs, approximately 29 were deficiencies and the remainder consisted of enhancements, material obsolescence, or technical questions. Outstanding DCRs and MMODs totaled 16 and 13 respectively. The inspector reviewed the outstanding TMODs with a backlog total of 47. The inspector noted approximately 22 TMODs that were implemented in or prior to 1993. The licensee has planned TMOD closeout for all outstanding TMODs. The outstanding ESAR's totaled approximately 15.

The inspector determined the licensee effectively prioritizes and manages the engineering backlog. Overall, the present quantity of outstanding items totals appear to be manageable with the current trend being downward. The upfront Engineering supervisory review in the RES process ensures proper prioritization for resolution of the issue. The routine and periodic review of the engineering backlog was a strength. However the inspector considered, in many cases, TMOD closeout was less than timely. The inspector had no further questions.

5.0 PLANT SUPPORT (71707,71750)

5.1 Radiological Controls

The inspector observed implementation of radiological controls during tours in the radiologically controlled area (RCA). Random sampling of portable hand held friskers and portal monitors demonstrated that they were calibrated as required by station procedures. The inspector determined by observation of several tasks in the radiologically controlled area that the licensee was effectively implementing radiological controls to minimize the spread of contamination and incorporating as-low-as-is-reasonably-achievable principles. A comprehensive assessment of refueling outage radiation protection is provided in Attachment 1 to this report.

5.2 Security

The inspectors reviewed the conduct of the security force throughout the refueling outage. Security personnel effectively controlled protected area personnel ingress, with emphasis noted during shift change periods. Personnel and material searches were observed to be thorough and unaffected by foot traffic. Within the station, security barriers required to be degraded to support outage activities were observed to be properly compensated, with the attendant security force member knowledgeable of the associated posting orders. Excellent control and accountability of personnel and material entering and exiting primary containment was also noted. Further, visitors and vehicles were routinely noted to have been properly processed into and escorted within the protected area.

6.0 SAFETY ASSESSMENT/QUALITY VERIFICATION (92700)

6.1 Licensee Event Report Review

The inspectors reviewed Licensee Event Reports (LERs) submitted to the NRC to verify accuracy, description of cause, previous similar occurrences, and effectiveness of corrective actions. The inspectors considered the need for further information, possible generic implications, and whether the events warranted further onsite followup. The LERs were also reviewed with respect to the requirements of 10 CFR 50.73 and the guidance provided in NUREG 1022 and its supplements.

6.6.1 LER 95-01-01, Inadequate Overtemperature Delta T and Overpower Delta T Channel Calibrations.

LER 95-01-01, dated August 30, 1995, supplemented the original July 7, 1995 LER 95-01, that had documented the inadequate channel calibrations. The root cause determination for the event had not been completed prior to the submittal of the original LER, therefore the licensee committed to issue a supplemental report following completion of the causal determination. Previously, the inspector independently reviewed this event in NRC Inspection Report No. 50-443/95-06, Section 3.3 and reviewed the initial LER submittal in NRC Inspection Report No. 50-443/95-08, Section 6.1.1.

The licensee initiated Adverse Condition Report, ACR 95-143, to document the root cause analysis. The root cause of the inadequate channel calibration surveillances was determined to be a lack of design engineering involvement in the development of the original surveillance procedure. It was concluded that the original procedure writers lacked the technical engineering basis to ensure proper instrument loop overlap existed during the channel calibrations. A potential secondary contributing cause involved weak documentation for the bases for exceptions to overlap testing requirements that had been developed during a 1988 overlap testing requirements review that had been conducted by the maintenance department. Corrective actions to this event and causal determination included; 1.) verification that the instrument loops in question were within appropriate calibration, 2.) formation of a task team to address the overlap issue from a multi-disciplinary perspective, and 3.) verification that the Procedure Upgrade Program and procedure writers guide develop appropriate technical bases and standardized comprehensive procedures to ensure instrumentation calibrations are completed in accordance with facility license requirements and industry standard practices. The inspector independently reviewed the completed ACR, and had no questions regarding the LER supplement.

7.0 NRC MANAGEMENT MEETINGS AND OTHER ACTIVITIES (71707,40500)

7.1 Routine Meetings

At periodic intervals during this inspection, meetings were held with senior plant management to discuss licensee activities and areas of concern to the inspectors. At the conclusion of the reporting period, the resident inspector staff conducted an exit meeting on February 2, 1996, summarizing the preliminary findings of this inspection. No proprietary information was identified as being included in the report.

7.2 Other NRC Activities

During the weeks of November 20-22, 1995, and November 29-December 1, 1995, an NRC Region I Radiation Specialist performed an inspection of the radiological protection program implemented during the refueling outage. The results of this inspection are included as Attachment 1 to this report.

During the week of November 29-December 4, 1995, an NRC region I specialist inspector from the Division Of Reactor Safety reviewed in-service inspection (ISI) program activities, and engineering and licensing actions to address two unresolved items. The results of this inspection are included as Attachment 2 to this report.

During the week of December 11-December 15, 1995, an NRC Region I specialist inspector from the Division Of Reactor Safety performed an inspection to closeout open inspection items identified during the electrical distribution system functional inspection (EDSFI) performed in 1993. The results of this inspection are included as Attachment 3 to this report.

NRC Inspection Report No. 50-443/95-15

ATTACHMENT 1

Radiation Protection Inspection

U.S. NUCLEAR REGULATORY COMMISSION
REGION I

DOCKET/REPORT NO.: 50-443/95-15

LICENSE NO.: NPF-86

LICENSEE: North Atlantic Energy Service Corporation
Seabrook, New Hampshire 03874

FACILITY: Seabrook Station

INSPECTION AT: Seabrook, New Hampshire

INSPECTION DATES: November 20-22, 1995, continued November 29 through December 1, 1995

INSPECTOR: Lonny Eckert — 1/4/96
L. Eckert, Radiation Specialist — Date
Radiation Safety Branch
Division of Reactor Safety

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

Areas Inspected: Implementation of the radiological protection program during a refueling outage. Areas included changes in the radiation protection program; the program to maintain exposures as low as is reasonably achievable (ALARA); external exposure control; internal exposure control; and control of radioactive materials and contamination. Where possible, performance insights were gained by direct work observation.

1.0 CHANGES TO THE RADIATION PROTECTION (RP) PROGRAM

1.1 Outage Staffing

The inspector reviewed the RP outage organization to determine whether staffing was sufficient to maintain occupational radiation protection safety in a period of stress on the RP organization. The inspector interviewed station personnel and observed work activities. The inspector assessed that the outage RP organization was well staffed to meet the outage workload. The inspector based this conclusion on observations that both the licensee and contractor RP staff were well-qualified, experienced, and well-supervised. The inspector also observed that RP supervision spent considerable time in the field, RP functions were generally staffed for continuous outage support, and RP field operations technicians were assigned to areas of the station to provide more dedicated coverage. No situations were noted in which RP technicians were overly burdened.

1.2 Thermoluminescent Dosimetry (TLD) Program

The TLD laboratory program at Seabrook Station had been eliminated. The corporate office in Berlin, Connecticut now provides this service to Seabrook Station. The Berlin, Connecticut TLD program was accredited by NVLAP as required.

1.3 Radiologically-Controlled Area (RCA) Access Controls

Major changes were made by the licensee relative to access control to the RCA. The inspector reviewed a newly-procured Merlin Gerin electronic dosimeter and radiologically-controlled area (RCA) access control system and reviewed the changes in how radiation work permits (RWPs) were developed.

All individuals entering the RCA were provided with an electronic dosimeter and signed onto a computer-based RWP. The inspector interviewed RP personnel, used the system during the course of the inspection, and observed the flow of personnel through the RCA RP control point. Overall, the inspector assessed that this new system has significantly improved the licensee's ability to provide real-time monitoring of exposures and should also minimize RWP compliance problems. The inspector based this assessment on the following observations:

- Workers were able to monitor their accumulated exposure and area dose rate.
- Workers could change to a different radiation work permit or task in the field without returning to the RCA RP control point.
- No breakdown in RCA access controls was noted during periods of high personnel flow through the RCA RP control point, such as the initial morning entries and lunch break.

- Junior RP technicians were stationed at the RCA boundary to ensure that workers made proper entries and that the electronic dosimeters had been properly reset.

TLDs remain as the primary dosimeter by which the dose of record was assessed and assigned. The electronic dosimeters were being used as a control device. The licensee was retaining exposure data for future TLD to electronic dosimeter comparison studies to determine if electronic dosimeters could be used as the primary device for dose of record.

Along with the implementation of the electronic dosimeter and RCA access control system, the licensee RP staff initiated a program change in which radiation work permits (RWPs) were established to be more general in nature as compared to RWPs from previous outages. The inspector selected several RWPs written to support OR04 (the fourth refueling outage) outage activities, compared them to similar RWPs from OR03, and interviewed RP personnel. The inspector had two main observations of this change:

- The inspector assessed that the change toward more general RWPs lightened the administrative burden on workers because there were significantly less RWPs this outage, of which workers needed to maintain an awareness. During OR04 there were fewer RWP compliance problems as compared to OR03. Also, there were no improper high radiation area entries during OR04 as had occurred during OR03.

- The inspector noted that this change placed additional burden on the personnel responsible for making ALARA reviews because of the need to manually determine the expected exposures for sub-elements of a generally defined task as characterized by the RWP.

No degradation of the RP program was evident. These changes will be reviewed further as part of the routine NRC inspection program.

1.4 Radiation Department Guidance

The inspector reviewed several newly-developed guidance documents for RP technicians called health physics operational guidelines (HPOGs) and interviewed RP personnel. The inspector considered these to be a good initiative, because they better delineated RP management's expectations in how certain RP-related functions were to be conducted.

2.0 GENERAL OBSERVATIONS

Tours of RCA were conducted to observe work in progress during the outage. The inspector conducted surveys within the containment building and found that radiologically-controlled areas had been appropriately established in accordance with Nuclear Regulatory Commission regulations and licensee procedures. No posting discrepancies were noted. Good radiation worker practices were exhibited by workers.

Overall, the inspector assessed that housekeeping was very good, considering that a refueling outage was in progress. The inspector observed very little combustible material in the RCA.

No skin exposures of regulatory significance were noted at the time of the inspection.

3.0 PROGRAM TO MAINTAIN OCCUPATIONAL EXPOSURES ALARA

The inspector reviewed the ALARA program for OR04 activities. The inspector reviewed work activities, relevant documentation, and interviewed RP personnel. Overall, ALARA performance during OR04 was assessed to be very good. The inspector based this assessment on the following observations:

- The station ALARA goal for 1995 was established at 113 person-rem. The station ALARA goal included 100 person-rem for OR04 and 13 person-rem for routine operations. The station target (incentive based) OR04 ALARA goal was set at 87 person-rem. At the time of the inspection, the licensee was performing better than what had been expected and appeared to be able to meet the outage target goal.

- Very good results were noted from plant shutdown chemistry. For OR04, a total of 2421 Ci of Co-58, 25 Ci of Co-60, and 29 Ci of Mn-54 were removed from the reactor coolant system. RP representatives stated to the inspector that sufficient time for cleanup had been built into the OR04 schedule prior to the start of major work within containment.

- During tours, the inspector noted that the licensee had made good use of teledosimeters. This was especially notable during work on the steam generators. The inspector also noted that RP supervision peared to spend more time in the field as compared to refueling outage OR03. RP technicians on the refueling floor were notably attentive in implementing hot particle controls as equipment or personnel left the cavity.

- The inspector evaluated the licensee's ALARA reviews (a mechanism by which jobs are planned to incorporate dose-reduction and control techniques for controlling internal and external exposures, and to incorporate contamination controls).

  One example of an inadequate ALARA review was noted. This concerned the reactor head guide funnel inspection and repair job. Engineering was assigned to lead the ALARA review for the job, and provided the ALARA planner. The inspector was informed by the ALARA supervisor that the review was not started in a timely manner so as to take full advantage of industry experience. Notwithstanding, a positive aspect in controlling this job was that the lead planner stopped the job after the first guide funnel inspection when it was evident that considerably more exposure than expected was experienced. Subsequently, the conduct of the reactor head guide funnel inspection was postponed for a future refueling outage.

Notwithstanding this example, ALARA planning was generally effective. The inspector did not note any significant problems in implementing the ALARA reviews, and did not identify other situations in which the ALARA review could have been significantly improved to further reduce exposures.

- The inspector observed portions of a reactor cavity drain-down evolution. The station staff responded well to a 500 Rad/hr hot spot (a contact reading) in a cavity drain line. Engineering provided timely support in reanalyzing their operational restrictions on mechanical agitators that had been installed on the cavity drain lines. RP personnel monitored the drain lines as the drain-down was conducted, and immediately guarded the immediate area upon discovery of the high contact dose rate. The RP control point was in direct view of the primary loop area access point (controlled as a high radiation area), and personnel were challenged as to whether their entry was absolutely necessary at that time. Operations provided timely support in flushing the cavity drain line until the radiation levels reached a more manageable level.

4.0 PERSONNEL CONTACTED

* B. Cash, Health Physics (HP) Department Supervisor
* W. DiProfio, Station Manager
* S. Dodge, Radiation Services Department Supervisor
* J. Grillo, Operations Manager
* W. Leland, Chemistry and HP Manager
* J. Linville, Chemistry Department Supervisor
* J. Peschel, Regulatory Compliance Manager
* J. Rafalowski, Chemistry and HP Projects Supervisor
* J. Sobotka, NRC Coordinator
* R. Sterritt, HP Supervisor, ALARA
* F. Straccia, Senior Health Physicist
J. Tarzia, Senior Health Physicist
R. Thurlow, Senior Health Physicist

* Denotes an individual who attended the 12/1/95 exit meeting.

Other licensee personnel were contacted during the inspection.

NRC Inspection Report No. 50-443/95-15

ATTACHMENT 2

Engineering and In-service Inspection Program Inspection

REPORT DETAILS FOR SEABROOK INSPECTION NO. 50-443/95-15

DOCKET/REPORT NO: 50-443/95-15

LICENSEE: North Atlantic Energy Service Corporation

FACILITY: Seabrook Station

INSPECTION AT: Seabrook, New Hampshire 03874

INSPECTION DATES: November 29-December 4, 1995

INSPECTOR: Antone C. Cerne, Reactor Engineer

Antone C. Cerne 12/14/95

Antone C. Cerne, Reactor Engineer
Civil, Mechanical, and
Materials Engineering Branch
Division of Reactor Safety

Date

APPROVED BY: Michael C. Modes 12/15/95

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

Date

Areas Inspected: This inspection involved a review of licensee engineering and licensing actions to address two unresolved items. An amendment to the plant technical specifications and a revision to the updated FSAR were reviewed, along with supporting calculations and other design documents and procedures. The inspector assessed the adequacy of licensee controls for the main steam safety valve lift settings and associated trip setpoints, in addition to the adequacy of the design of the containment isolation configuration of the hydrogen analyzer piping loops. Additionally, the inspector examined the eddy current results and records for the steam generator tube inspections conducted during the current refueling outage (ORO 4). The inspector also conducted a sample review of the inservice inspection (ISI) program in progress, focusing upon the nondestructive examination (NDE) results. Licensee management oversight and quality assurance of both the eddy current testing and ISI activities were evaluated through discussions with the personnel involved and a review of in-process and completed records. The inspector conducted an exit meeting with station management and the responsible technical and QA personnel at the conclusion of this inspection.

DETAILS

1.0 ENGINEERING FOLLOWUP

The inspector reviewed licensee actions to address previously-identified findings. One issue involved the review of the adequacy of the design criteria for the containment isolation features of a safety-related system with piping that penetrates containment from the outside with a closed-loop configuration. The other open item related to the verification of engineering calculations supporting revisions to the safety valve lift settings documented as limiting conditions for operation (LCO) and the associated trip setpoints prescribed as action requirements in the plant technical specifications (TS). Both of these issues had been previously documented as unresolved items (URI) that required engineering resolution of the technical questions. Actions taken by the licensee to clarify its regulatory position in each case were evaluated as follows:

(Closed) URI 50-443/92-80-02; Hydrogen Analyzer Piping Loop and System Design:

The licensee verified that the hydrogen analyzer loop sections of the combustible gas control (CGC) system meet the design criteria of American National Standard ANSI/ANS-56.2 for a closed system outside containment. The inspector reviewed the nine criteria, published by the American Nuclear Society (ANS), and evaluated the system design relative to the containment isolation provisions delineated in USNRC Regulatory Guide 1.141. Consistency with the updated FSAR system description for seismic category, system integrity, and post-LOCA design was established and the inspector noted that a licensee UFSAR change request clarified the containment isolation barriers in place to meet the 10 CFR 50, Appendix A, General Design Criteria (GDC 56), as "acceptable on some other design basis."

The licensee also issued a modification document (MMOD 94-0570) that addresses the non-ASME portion of the hydrogen analyzer loops, maintaining the ANS Safety Class 2 categorization for the Class 1E (non-ASME) hydrogen analyzers. The inspector reviewed the 10 CFR 50.59 evaluation associated with this MMOD and checked relevant UFSAR changes and piping and instrumentation drawing (P&ID) revisions. A 1994 revision to the procedure (OS1023.71), governing the operation of the hydrogen analyzers, was also examined to assess closed and locked-closed valve controls and the CGC system configuration during various operational conditions. The inspector noted that the usage of both system lineup and independent verification of valve position checklists was procedurally mandated.

The licensee's control of the CGC hydrogen analyzer loops as "closed systems" outside containment appears to meet the GDC, as augmented and endorsed by the applicable national standards and regulatory guidance. The inspector confirmed that the licensee, through UFSAR changes and procedural and drawing revisions, has clarified the safety categorization, design requirements, and operational provisions for

these CGC loops and the components within the containment isolation boundary. The inspector has no additional questions regarding this URI and considers this item to be closed.

(Closed) URI 50-443/95-08-01; Main Steam Safety Valve Setpoint Resolution:

The TS have been revised (Amendment No. 43) to document new lift settings for each main steam safety valve (MSSV). New TS values (as a percent of rated thermal power) for the power range neutron flux high trip setpoint to be adjusted with inoperable MSSVs, were also promulgated in the same amendment. The inspector reviewed the latest calculations (SBC-698, Revision 1) provided by the Yankee Nuclear Services Division to support these TS changes. The inspector also reviewed Crosby Valve & Gage Company data on the MSSVs supplied to Seabrook Station and generic EPRI safety and relief valve test results (WCAP-10105), which provide some of the documented bases for the setpoint tolerances.

While the licensee still assumes in the new engineering calculations that the MSSV accumulation is zero (i.e., the valves "pop open" at the required set pressure without overpressure considerations), the additional assumption of a 3% setpoint tolerance (i.e., the valves do not lift to provide the rated flow until the pressure reaches the TS lift setting plus 3%) establishes a conservative approach to accounting for various tolerances in the calculational model This Revision 1 to SBC-698 not only affected the final TS setpoints, but also those published in TS Clarification, TS-011; in effect, further reducing the maximum allowable power range neutron flux high setpoint for continued operation with inoperable MSSVs. Revision 2 to TS-011 was issued on August 29, 1995, prior to the downpower and MSSV testing associated with the current refueling outage (ORO 4). [NOTE: The resident inspector followup of this MSSV trevitesting is documented in 95-15, with the as-found results being further evaluated by the licensee for TS compliance and potential regulatory reporting.]

NRC Inspection Report 50-443/95-13

The inspector also noted that the revised TS 3/4.7.1.1 bases are consistent with the SBC-698, Revision 1, valve setpoints and rated steam flow capacities at the 103% setpoint pressure value; and the methodology for deriving the reactor trip setpoints, based upon minimum MSSV steam flow relief capacity, is also documented in the TS bases for safety valve operation. This methodology was utilized in SBC-698 (both Revisions 0 & 1) to not only calculate the revised TS values, but also verify that the MSSV trevitesting during the previous (ORO 3) downpower met TS and ASME Code criteria for main steam system overpressure protection. The inspector discussed the conclusions reached as a result of SBC-698 (Revision 1) calculations, as well as the assumptions and supporting vendor (Crosby) data, with the cognizant licensee engineer. While the original TS 3.7.1.1 requirements, as well as those modified by TS-011 (Revision 1), were identified to have been nonconservative,

system operability was not in question. The LCO and action requirements in the current TS appear to be based upon sound calculations, resulting in appropriately conservative MSSV lift settings and engineered trip setpoints. The open NRC questions on this issue have been satisfactorily answered. Therefore, this URI is considered to be closed.

2.0 STEAM GENERATOR TUBE EDDY CURRENT EXAMINATION

The licensee performed eddy current examination (ET) of a percentage of the tubes in steam generators (S/G) "A" and "D" during ORO 4. In accordance with TS 4.4.5 S/G surveillance requirements and ET procedural controls (EX1807.014, Revision 1), over 42% of the tubes in each of these two S/Gs were inspected. This sample size satisfies all TS Category C-2 expanded sample size situations. The licensee's inspection plan included a bobbin coil examination of most of the tubes selected and, in response to NRC concerns identified in Generic Letter (GL) 95-03, a Cecco-5 probe inspection of the roll transition area of 500 tubes and a rotating plus-point probe of 25 Row 1 tubes (i.e., the minimum radius U-bend tubes) in each of the two S/Gs. The Cecco and plus-point inspections were specifically intended to identify circumferential cracking problems in the tube areas deemed most susceptible to such cracking concerns. Additionally, certain tube indications identified by the bobbin coil probe examinations were further inspected by a 3-coil rotating pancake probe. Overall, 2424 tubes in S/G "A" and 2444 tubes in S/G "D" were examined, with the inspection plan generally followed, except for an additional Row 1 tube in S/G "D" substituted for one of those planned in S/G "A".

The results of these ET inspections indicated a total of 12 "defective" tubes (i.e., exceeding the plugging limit of a 40% thru-wall indication). In all these cases, analysis of the indications confirmed causes related to anti-vibration bar (AVB) wear, which was a known area of potential tube degradation in the Seabrook S/Gs based upon the ET history during previous refueling outages. All 12 tubes were plugged, bringing the total number of plugged tubes in all four S/Gs to 36 (out of the total population of 22,504 tubes). The inspector reviewed the plugging history for all the S/Gs, noting that 13 of the 36 plugs were installed during S/G fabrication and preservice inspection activities, i.e., before commercial operation service conditions. Thus, the total number of plugged tubes, particularly those related to S/G service wear conditions, is recognized as a low number through the first four cycles of Seabrook operation.

The additional inspections conducted by the licensee in response to GL 95-03 resulted in the identification of no circumferential cracking defects. In reviewing the tube maps, provided by Westinghouse Electric Corporation (W) as the licensee's ET contractor, the inspector noted a compilation of the sludge pile distribution on the top of the tube sheet, which validated the high sludge region selected for the Cecco-5 inspection for circumferential cracking. In addition to the 12 new tube plugs, the licensee also replaced an existing plug of Inconel-600 material in the cold leg of S/G "A" with a new plug of Inconel-690 material. The inspector confirmed that the only Inconel-600 plugs remaining to be replaced reside in five cold-leg tubes in the "B"

and "C" S/Gs. The inspector reviewed the S/G tube plugging matrix through ORO 3 and the two work requests (95W000588 & 589) for tube plugging during ORO 4 and verified good process controls and accountability for the plugging operations.

The inspector also reviewed the W "Eddy Current/Plugging Reports" for S/G "A", dated November 27, 1995, and for S/G "D", dated November 28, 1995, checking for the ORO 4 distribution of degraded tubes and other indications, as well as the tube maps illustrating the various ET probe inspections by type and length of tubes inspected. The inspection results and the categorization of degraded and defective tubes were assessed by the inspector relative to the EX1807.014 procedural controls and were discussed with the cognizant licensee engineer. The inspector noted that the W lead data analysts were located at the Seabrook site, while primary and secondary ET analysts would perform a review of the electronically transmitted data at the W Waltz Mill facility in Pennsylvania. The inspector confirmed that all data analysts were qualified in accordance with EPRI guidelines and had received site-specific training and had passed qualification tests on the Seabrook ET data analysis guidelines. The certification and qualification records for the W NDE inspection personnel, including sub-vendor personnel, had been approved by a licensee ASNT Level III ET reviewer.

The inspector also discussed quality oversight of the ET inspection and tube plugging activities with a licensee Nuclear Quality Group Level III examiner who maintained control of the NDE certification records and with a Yankee Atomic Electric Company (YAEC) Level III examiner who observed the training and testing of personnel at the W Waltz Mill facility. Additional QA oversight of the S/G inspection activities is discussed in Section 4.0 of this inspection report. As a result of the records review, discussions with cognizant licensee process management and NDE personnel, and a sample correlation of ET results with the inspection plan and commitments to the NRC in licensee letters in response to GL 95-03, the inspector identified no unresolved safety issues. The ET results are consistent with the Seabrook Model "F" S/G design with its quatrefoil holes to minimize tube denting and with the thermally treated Inconel-600 tubes performing well in the mitigation of any circumferential cracking concerns. The inspector verified the cognizance of licensee management of the AVB wear representing the most significant cause of major tube degradation (albeit, in a small number of tubes) to date.

3.0 INSERVICE INSPECTION (ISI)

The inspector examined a status report for all NDE scheduled to be performed in accordance with ASME Section XI requirements during ORO 4. As a result of plant configuration issues (e.g., staging requirements) and scheduling conflicts (e.g., S/G weld examinations vs. tube ET conduct), certain ISI was deferred until the next refueling outage with appropriate weld substitutions selected for ORO 4 examination. Such items, as well as the selection of expansion samples and the need to resolve ISI plan anomalies, were documented in a list of issues being tracked by the licensee's ISI program coordinator. The inspector discussed these issues with licensee engineering and YAEC Level III staff personnel, verifying the expansion sample size and population of

valve bolts requiring additional inspection as a result of the identification of a loose nut (i.e., visual examination - VT). The inspector also reviewed the magnetic particle testing (MT) sheets and the ultrasonic testing (UT) inspection records for a sample of reactor pressure vessel studs and discussed the examination techniques and sequence with knowledgeable licensee personnel.

Additionally, the inspector examined some ASME pipe weld UT, MT, and liquid penetrant testing (PT) results, noting that where surface NDE revealed indications, a volumetric (UT) inspection was conducted. The removal of surface indications by grinding was followed by reexamination with the original NDE technique, as well as the conduct of a UT wall-thickness check to assure minimum wall criteria. The inspector confirmed for one vessel (S/G "A") seam weld, the UT techniques included a longitudinal wave scan and shear wave scans using two separate angles. For other components, different multiple UT-scan techniques were used to maximize the weld coverage where geometric interferences rendered certain areas inaccessible. The inspector discussed the code requirements for such vessel weld examinations with licensee NDE personnel.

Based upon discussions with the licensee, the inspector was informed that no weld repairs were required as a result of ISI activities during ORO 4. However, as of the conclusion of this inspection, all of the NDE results had not yet been analyzed, and the licensee had not yet determined what waivers from ASME Section XI ISI requirements would have to be prepared for submission to the NRC. Also, as in the case of ET, the inspector verified that the NDE certification records for the contractor (NES, Inc.) inspection personnel had been reviewed and approved by licensee NDE Level III examiners. The inspector identified no concerns involving the qualification of the personnel or the performance of NDE activities and no technical issues regarding the conduct of the ISI program at Seabrook Station during ORO 4.

4.0 MANAGEMENT OVERSIGHT

The inspector discussed with quality assurance management, inspection, and NDE personnel the surveillance and audit activities in progress for the oversight of both the S/G eddy current testing and ISI program controls. A QA surveillance report (QASR 95-0069) covering the special NDE processes for ORO 4 was reviewed for the type of observations performed and the criteria established for acceptance. From an interview with a field inspector and review of the in-process inspection notes, the inspector was able to determine that a comprehensive set of quality criteria was being checked as part of the QA overview, particularly in the area of S/G tube ET and plugging controls. A surveillance of the W program for the remote transmission of ET data and analysis of the results by properly trained, tested, and qualified NDE personnel was performed at the request of the licensee QA department (reference: 95QSR-0036) by YAEC personnel in November 1995. The inspector verified good control by the responsible licensee Level III examiner of the qualified worker lists for ET and other NDE activities.

Additionally, the inspector interfaced with the licensee's ISI program coordinator and a YAEC Level III examiner for the review of S/G ET status reports, the "Supertubin" records received from W, and the NDE results and

reports submitted in fulfillment of ASME Section XI weld and component inspection requirements. Licensee personnel were knowledgeable of the Code, TS, and overall program provisions and were able to relate to the inspector the current project status in detail and to respond to specific questions involving both NDE methodologies and inspection sampling techniques. The inspector determined that the YAEC personnel provide a technically-competent, yet independent, support function to the licensee capabilities in this regard. The licensee's supervisory oversight of the contractor NDE activities, coupled with the surveillance/audit activities performed by the QA department, appear to have established the desired level of quality and appropriate assurances that program requirements have been successfully accomplished.

5.0 MANAGEMENT MEETING

The results of this inspection were discussed with licensee technical, QA, and management personnel, including the Station Manager, at an exit meeting on December 4, 1995. The licensee acknowledged the preliminary findings and the inspector's conclusionary remarks. No proprietary information that was reviewed during the inspection is intended to be documented in this inspection report. No unresolved regulatory issues or open technical items were identified during this inspection.

NRC Inspection Report No. 50-443/95-15

ATTACHMENT 3

Electrical Distribution System Functional Inspection Follow-up

U. S. NUCLEAR REGULATORY COMMISSION
REGION I

DOCKET/REPORT NOS: 50-443/95-15

FACILITY: Seabrook Station

LICENSEE: North Atlantic Energy Service Corporation (NAESCO)

LOCATION: Seabrook, New Hampshire

INSPECTION DATES: December 11-15, 1995

INSPECTOR: Leonard S. Cheung — 1/6/96
Leonard Cheung, Sr. Reactor Engineer
Electrical Engineering Branch
Division of Reactor Safety
Date

APPROVED BY: A. Dell'Orso / WHR — 1/18/96
William H. Ruland, Chief
Electrical Engineering Branch
Division of Reactor Safety
Date

Areas Inspected: This was an announced inspection to review the status of previously-identified electrical distribution system functional inspection (EDSFI) items and to determine the adequacy of the licensee's corrective actions to resolve these items. This inspection also covered a review of management oversight for resolving electrical engineering issues.

DETAILS

1.0 PURPOSE (2515/111)

The purpose of this inspection was to review the status of the open items identified during the 1993 electrical distribution system functional inspection (EDSFI), and to determine the adequacy of the licensee's corrective actions in resolving each issue.

2.0 STATUS OF PREVIOUSLY-IDENTIFIED INSPECTION ITEMS

2.1 (Closed) Unresolved Item 50-443/93-80-02 - Associated Circuit Components

This item consisted of three separate circuit breaker issues that required further evaluation or justification from the licensee. The three issues are: (A) nonenvironmentally-qualified circuit breakers inside containment; (B) commercial grade components in associated circuits without appropriate qualification or dedication; and (C) circuit breakers for which qualification was not demonstrated by periodic testing in accordance with the electrical safety evaluation report (SER). The licensee's corrective actions for each issue are discussed below:

A. During the May 1993 EDSFI, in response to the team's questions, the licensee identified 10 circuit breakers (in Panels 1-PP-8A and 1-PP-8B) inside the reactor containment that were used to protect associated circuits that shared the same cable trays with safety-related cables. Prior to that time, the licensee always assumed that all such breakers were in mild environments. Therefore, the breakers were not in the environmental qualification (EQ) program. The licensee completed an operability determination during the EDSFI and concluded that there were no safety issues. The operability determination was accepted by the EDSFI team.

   Following the EDSFI, the licensee sent two breakers removed from panel 1-PP-8A and two new breakers to Acton Laboratories in Acton, Massachusetts, for a harsh environment test. The test result indicated that all breakers functioned properly as documented in Engineering Evaluation 93-24, entitled, "Final Evaluation of Environmental Effects on Circuit Protection Devices," dated July 29, 1993. The licensee also determined that environmental qualification of these breakers was not required. For additional margin, the licensee issued a plant modification (DCR 93-0040) to: (1) modify the affected cable routing, and (2) relocate the circuit breakers (using a new panel and new breakers) to outside the reactor containment in a mild-environment area. The new panel and new breakers were installed during the spring 1994 refueling outage. The inspector examined the installed breakers and found no adverse conditions. The inspector concluded that the licensee's corrective actions were appropriate. This issue is resolved.

B. During the 1993 EDSFI, in response to the team's questions, the licensee identified 13 associated-circuit breakers that were procured as commercial grade items without proper dedication. These breakers were used as protective devices with associated circuit requirements (PDWACR). The Seabrook updated final safety analysis report (UFSAR) at

that time indicated that the components in associated circuits were of identical design as the Class 1E counterparts and had been purchased to the same specification requirements inclusive of quality control.

Following the EDSFI, the licensee evaluated the 13 associated circuit breakers and found that only three 120 Vac breakers were used to protect cables that actually shared raceways with cables carrying Class 1E loads. The licensee also verified that these breakers were identical in design (same model and part numbers) as Class 1E breakers. The evaluation was documented in the resolution for station information report (SIR) 93-35. The licensee also trip-tested these circuit breakers and demonstrated that all three breakers functioned properly.

The inspector also reviewed the following licensee corrective actions:

(1). The licensee had developed a corporate procedure, NM 17240, "Associated Circuit Program," to delineate programmatic requirements and responsibilities related to associated circuits and protective devices. The inspector's review of this procedure indicated that it clearly defined associated circuits and their protective devices (circuit breakers and fuses), appropriately discussed the programmatic requirements of the protective devices, and assigned functional responsibilities. Implementation of these programmatic requirements was covered by Administrative Procedure, MA 7.3, "Testing and Inspection of 1E Protective Devices," dated July 12, 1995, and Engineering Design Procedure 38120, "Electrical Separation Associated Circuits and Other Unique Criteria," dated March 31, 1995. The inspector determined that these three procedures thoroughly addressed the programmatic requirements for associated circuit protective devices.

(2). The licensee had issued Engineering Evaluation 93-34, "Associated Circuit Protective Devices," to identify the installed PDWACRs. The inspector's review of this document indicated that the evaluation was thorough, and contained a list of PDWACRs. In addition, supplementary drawings (1-NAY-300230, sheets 69a through c) were generated by engineering for use by station personnel.

(3). The licensee had issued a procurement procedure (PM 3.6), "Procurement of Nonsafety-related Items with Special Requirements" to provide administrative controls of PDWACRs. The inspector's review of this procedure (Revision 2, dated February 9, 1995) indicated that it clearly defined the requirements for PDWACR procurement. The licensee also revised Work Control Procedures MA 3.1, "Work Request," and PM 6.1, entitled, "Material Issues and Returns" to provide administrative controls of future installation or replacement of PDWACRs.

(4). The licensee had provided a two-hour training plus additional reading materials (lesson plan TS1082C) to technical, operations, and maintenance personnel on associated circuits. This training covered the design, testing, and procurement procedures. The inspector's review of the training records indicated that about 300 station and engineering staff completed the training that was conducted in several sessions in March 1993.

(5). The licensee had revised Seabrook UFSAR to specifically address and clarify the requirements for the design, procurement, and testing of associated circuits protective devices. The revision was completed on November 8, 1993, and submitted to the NRC on January 31, 1995. In the revised UFSAR, the licensee used "similar" in the new version instead of "identical" in the old version, but provided clear definition of "similar" in their associated circuit program, as "identical part number except documentation requirements." The inspector's review of the FSAR change package indicated that appropriate justifications were provided for the revision. Because appropriate controls were provided for the associated circuit components in the new associated circuit program, the licensee determined that changing the UFSAR from "identical" to "similar" would not decrease the safety margins and would not create unreviewed safety questions.

The inspector concluded that the above corrective actions were extensive and appropriate and the second issue of this unresolved item was resolved.

C. During the May 1993 EDSFI, the team noticed that the licensee did not conduct inspections and testing of the associated circuit protective devices as described in the electrical SER. Following the EDSFI, the licensee tested all circuit breakers associated with PDWACR. The licensee also developed Test Control Procedure MA 7.2, "Testing and Inspection of Protective Devices with Associated Circuit Requirements," to cover periodic testing and inspections of all PDWACR molded case circuit breakers (MCCB). These breakers were to be tested in a 10-year frequency. About 15% were to be tested in each refueling cycle. The inspector's review of the test control procedure indicated that it had established appropriate inspection and test requirements. The inspector also reviewed the computer printout for the breaker test schedules, and noticed that all breakers were scheduled within 480 weeks (less than 10 years). The inspector concluded that the licensee had established a periodic test program to demonstrate operability for the associated circuit breakers.

Therefore, this unresolved item is closed.

2.2 (Closed) Unresolved Item 50-443/93-80-03 - Lack of Periodic Trip Testing of Associated Circuit Breakers

During the May 1993 EDSFI, the team noticed that the NRC safety evaluation report for the Seabrook electrical system specified that periodic trip-testing of associated circuit breakers was to be implemented. Following the EDSFI, the licensee issued SIR 93-36 to list all associated circuit breakers that had not been tested and developed Test Control Procedure MA 7.2, "Testing and Inspection of Protective Devices with Associated Circuit Requirements," for testing those breakers. The licensee completed testing of all breakers listed in SIR 93-36 using Test Procedure MA 7.2 on July 29, 1994. The licensee scheduled periodic testing of the associated circuit breakers on a 10-year frequency. The inspector reviewed the computer printout and verified the test schedule to be within 10 years. This item is closed.

2.3 (Closed) Notice of Violation 50-443/93-80-07 - Qualification of Emergency Diesel Generator (EDG) Control Air System

During the 1993 EDSFI, the team determined that the licensee's design review failed to recognize that the emergency diesel engine jacket-water-cooling control valves (one for each diesel engine) were required to be functional for the full seven-day post-accident operation. This item had been updated during the September 1994 inspection (50-443/94-21). The seismic qualification of the emergency diesel generator (EDG) starting air compressors and the auxiliary components was reviewed during that inspection and was determined to be acceptable. The remaining corrective actions, that needed to be verified for the closure of this violation, were:

A. Alarm response procedures for restoring power to MCC 511 and MCC 611 following a seismic event;

B. The minor modification for revising the UFSAR and design documents to reflect the appropriate safety classification of EDG starting air components;

C. Installed starting air system equipment has been upgraded via commercial grade dedication to ensure that only items of proper safety classification are used for replacement parts in the starting air system;

D. Maintenance programs (including IST program) and procedures for the whole starting air system;

E. The evaluation for addressing the EDG reliability as a result of reclassification of control air components; and

F. The program to trend air consumption of the EDG air system to be used in the development of a technical clarification to address the impact of air system preventive maintenance on EDG operability.

The inspector verified the above corrective actions as follows:

A. The inspector reviewed the Seabrook Station alarm response procedure for "Starting Air Pressure Low," Revision 4, which was set at 460 psig for both EDGs. The response steps clearly prescribed actions required to restore power to MCC 511 and MCC 611.

B. The licensee issued Minor Modification 92-0556, "Diesel Generator System Components Safety Reclassification," on September 10, 1993, to upgrade the system components from nonsafety-related to safety-related. This modification was also used to revise the USFAR to reflect the component upgrades. The inspector reviewed this document and found it to be comprehensive. The inspector also verified that the safety class of the air compressors had been changed from nonsafety to Safety Class 3 and the drawing for the jacket water control valves was also changed from nonsafety to safety.

C. Following the 1993 EDSFI, the licensee issued SIR 93-37 to address the upgrade of the diesel engine compressed air components using commercial grade item dedication (CGID) methodology. There were approximately 60 CGID packages involved. The results of these CGIDs were documented in Engineering Evaluation 93-39, "Engineering Evaluation for Diesel Generator System Component Safety Reclassification," currently Revision 2, dated May 30, 1995. The inspector reviewed two CGID packages and found them appropriate.

D. The inspector reviewed Inservice Testing (IST) Procedure MA 6.5, "Inservice Testing of Valves," dated April 28, 1994, and verified that the diesel air start system valves were included in the IST program. The inspector also reviewed Station Surveillance Test Procedure OX 1426.14, "Diesel Generator Cooling Water and Air Start System Valves Quarterly Surveillance," Revision 4, dated May 4, 1994, and verified that the air start system valves were in the surveillance program.

E. Seabrook EDG reliability was based on station-specific data of diesel system failures that included components and subsystems, such as the EDG-control-air subsystem. Since no hardware changes were involved in the EDG-control-air subsystem reclassification, the licensee concluded that Seabrook EDG reliability would not be affected. The licensee evaluation was documented in two memoranda entitled, "EDG Control Air Reclassification Effects on EDG Reliability," one dated November 12, 1993, and another dated January 4, 1996, from L. Rau to J. Vargas.

F. The licensee decided not to trend the air consumption rate of the EDG air system. Instead they took a more conservative approach by revising Seabrook Station Operations Procedure 051026.04, "Operating DG 1A Starting Air System," to declare the EDG inoperable when the air start system was being serviced. The inspector reviewed Procedure 051026.04 and noted that Section 3.1 of this procedure stated that, "The diesel generator shall be considered inoperable when the air-start-system receivers, air headers, or starting-air compressor are out-of-service."

In addition to the above, in their September 15, 1993, letter in response to this violation, the licensee also committed to develop a design basis document for the EDGs, including the safety classification of support systems, by December 31, 1994. The inspector reviewed DBD-DG-01 entitled, "Design Basis Document, Emergency Diesel Generator - Mechanical," Revision 0, dated January 27, 1995, and verified that Section 2.3 of this document described the starting/control air system.

The inspector concluded that the licensee had completed extensive corrective actions for this violation. Therefore, this item is closed.

2.4 (Closed) Unresolved Item 50-443/93-80-06 - Minimum Fuel Oil Quantity for EDG Operations

During the 1993 EDSFI, the team determined that the calculated minimum fuel oil quantity requirement might not be adequate to meet the seven-day technical specifications (TS) requirement, because the fuel consumption rate was not justified.

Following the EDSFI, the licensee revised Calculation C-S-1-E-0161 using the fuel consumption rate that was based on actual testing of the EDGs. Since EDG "A" had a higher post-accident load, the licensee used the post-accident loading profile of EDG "A" for the required fuel oil quantity calculation. The fuel consumption rate obtained from testing was in gallons per kW-hr. Discussion with the licensee indicated that this consumption rate might not be conservative because the density of the fuel oil at the time of testing was unknown. The licensee agreed to revise the calculations using a conservative fuel oil density.

Following the conclusion of this inspection, the licensee transmitted the newly-revised calculation (C-S-1-E-0161, Revision 7, dated December 20, 1995) to the NRC for the inspector's review. The new calculation indicated that the fuel oil specific gravity could vary about 6% due to different ambient conditions predicted by the Seabrook service environment chart. To include other uncertainties such as the level instrument tolerance, the licensee determined to increase the TS value of the fuel oil storage tank to 62,000 gallons from 60,000 gallons. The licensee stated that administrative controls would be provided to maintain the new TS value until the TS change is finalized.

The inspector considered the licensee's corrective actions to be appropriate. This item is closed.

3.0 MANAGEMENT OVERSIGHT OF RESOLVING ENGINEERING ISSUES

The inspector reviewed the licensee management involvement in resolving engineering issues to assess the management oversight in this area.

Immediately following the May 1993 EDSFI, the nuclear production executive director requested the independent review team (IRT) to perform an independent audit to evaluate the programmatic controls of the Seabrook associated circuit program and to determine the causes of any programmatic or procedural deficiencies. The audit was completed in June 1993 by a multi-discipline audit team. The audit team determined that the programs and procedures for procurement, installation, and periodic inspection did not adequately incorporate the controls necessary to ensure full compliance with UFSAR and electrical SER commitments for associated circuits. The inspector's review of the audit report indicated that the audit was extensive and in-depth. This audit resulted in 24 recommendations in the areas of engineering, maintenance, quality assurance (QA) and management controls. These recommendations were implemented into the associated circuit program.

Additionally, two QA audits were conducted to review the revised associated circuit program. The first QA audit was conducted in November 1994 by a three-member audit team. The team identified five deficiencies in the procedure and testing areas. All findings were resolved in a timely manner. The second QA audit was conducted by a two-member team in August 1995, as a followup of the first audit. Two additional findings were identified in the areas of work control documentation and fuse control. These two findings were also resolved in a timely manner. The inspector's review of these two audit reports indicated that these audits were thorough.

The inspector concluded that excellent management oversight had been provided for the resolution of electrical engineering issues. However, the corrective action for establishing the EDG fuel consumption rate was not thorough in that the fuel oil density, which is temperature-dependent, was neglected in the calculations.

4.0 EXIT MEETING

The inspector met with the licensee personnel at the conclusion of the inspection, on December 15, 1995, and summarized the scope of the inspection and the inspection results. No proprietary materials were reviewed during this inspection. The licensee did not dispute the inspection findings at the exit meeting.

5.0 PERSONS CONTACTED

North Atlantic Energy Service Corporation

R. Bergeron	Electrical Engineering Manager
B. Beuchel	Mechanical Engineering Manager
S. Buchwald	QA Supervisor
R. Cliche	Design Engineering Supervisor
R. Jamison	Principal Engineer, YAEC
G. Kotkowski	Electrical Engineering Supervisor
N. Levesque	Electrical Maintenance Supervisor
J. Marchi	NSA Auditor
J. Peterson	Maintenance Manager
G. St. Pierre	Assistant Operations Manager

J. Sobotka	NRC Coordinator
J. Vargas	Engineering Manager

U. S. Nuclear Regulatory Commission

D. Mannai	Resident Inspector

Above personnel were present at the exit meeting on December 15. 1995.