UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30323

Report No.: 50-395/92-03

Licensee: South Carolina Electric & Gas Company
Columbia, SC 29218

Docket No.: 50-395 License No.: NPF-12

Facility Name: V. C. Summer Nuclear Station

Inspection Conducted: February 1-29, 1992

Inspector: for R. W. Wright 3/13/92
R. C. Haag, Senior Resident Inspector Date Signed

Inspector: for R. W. Wright 3/13/92
L. A. Keller, Resident Inspector Date Signed

Inspector: R. W. Wright 3/13/92
R. W. Wright, Project Engineer Date Signed

Approved by: F. Cantrell Jr. 3/13/92
Floyd S. Cantrell, Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope:

This routine inspection was conducted by the resident inspectors onsite in the areas of monthly surveillance observations, monthly maintenance observations, operational safety verification, ESF system walkdown, onsite follow-up of written reports of nonroutine events at power reactor facilities, onsite follow-up of events at operating power reactors, and review of nonconformance reports. Selected tours were conducted on backshift and weekends. Backshift and weekend tours were conducted on ten occasions.

Results:

The plant operated at or near 100 percent power throughout the inspection period with the exception of two brief power reductions. Power was reduced to 90 percent from February 6 until February 9, 1992 in order to replace the "B" main feed pump seals. On February 21, 1992, power was reduced to 83 percent power for less than one hour after receiving a high generator winding temperature alarm.

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A troubleshooting repair activity for a feedwater isolation valve identified a potential design deficiency that could effect valve reliability. Continued licensee investigation is needed to resolve this issue (paragraph 3). Repeated failures of a relief valve in the fire service system occurred prior to identifying and correcting the actual cause of the failures. An operability determination was made for this relief valve with only limited justification (paragraph 3). The cause of two mispositioned valves associated with the post accident hydrogen analyzer was not identified. The overall significance of the mispositioned valves was minor (pargraph 8a). The discovery of air in the chill water system identified the need for improved controls when adding chemicals to the system (paragraph 8b).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

F. Bacon, Acting Manager, Chemistry and Health Physics
K. Beale, Supervisor, Emergency Services
*C. Bowman, Manager, Maintenance Services
*M. Browne, Manager, Design Engineering
*B. Christiansen, Manager, Technical Services
*M. Clonts, Manager, Facilities and Administration
H. Donnelly, Senior Engineer, Nuclear Licensing and Operating Experience2
*M. Fowlkes, Associate Manager, Shift Engineering
S. Furstenberg, Associate Manager, Operations
*J. Graham, Engineer, Nuclear Licensing and Operating Experience
*W. Higgins, Supervisor, Licensing Support and Operating Experience
*S. Hunt, Acting General Manager, Nuclear Safety
*A. Koon, Manager, Nuclear Licensing and Operating Experience
*K. Nettles, General Manager, Station Support
H. O'Quinn, Manager, Nuclear Protection Services
*C. Osier, Acting Manager, Systems and Performance Engineering
*J. Proper, Associate Manager, Quality Assurance
*M. Quinton, General Manager, Engineering Services
*L. Shealy, Senior Engineer, ISEG
*J. Skolds, Vice President, Nuclear Operations
G. Soult, General Manager, Nuclear Plant Operations
*W. Stuart, Acting Supervisor, Primary System Engineering
*G. Taylor, Manager, Operations
*A. Torres, Associate Manager, Quality Control
*R. White, Nuclear Coordinator, S. C. Public Service Authority
*F. Zander, Coordinator, NOD Projects

Other licensee employees contacted included engineers, technicians, operators, mechanics, security force members, and office personnel.

D. M. Verrelli, Chief, Reactor Projects Branch 1, DRP, was onsite February 12, 1992, to review resident inspector activities and meet with licensee management.

R. W. Wright, Project Engineer, Reactor Projects Branch 1, DRP, was onsite Fe ruary 25-28, 1992, to review project status and help provide site coverage.

Bruce Kenyon, President and Chief Operating Officer of SCE&G, met with the resident inspector on February 28, 1992, to discuss any concerns or questions regarding plant activities.

*Attended exit interview

Acronyms and initialisms used throughout this report are listed in the last paragraph.

2. Monthly Surveillance Observation (61726)

The inspectors observed surveillance activities of safety related systems and components listed below to ascertain that these activities were conducted in accordance with license requirements. The inspectors verified that required administrative approvals were obtained prior to initiating the test, testing was accomplished by qualified personnel in accordance with an approved test procedure, test instrumentation was calibrated, and limiting conditions for operation were met. Upon completion of the test, the inspectors verified that test results conformed with technical specifications and procedure requirements, any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel, and the systems were properly returned to service. Specifically, the inspectors witnessed/reviewed portions of the following test activities:

* Inspection of fire dampers associated with train "B" of the control room ventilation system (STP 428.060).

* RCS loop B wide range hot leg temperature instrument calibration (STP 340.002).

* Slave relay testing for "B" train charging pump and emergency diesel generator (STP 105.016).

* Operability test of "B" emergency diesel generator (STP 125.002).

* Overcurrent trip testing for the "B" reactor make-up water pump breaker XSW1DB107D (STP 508.002). This procedure demonstrates that applicable 480 VAC circuit breakers used for cable overcurrent protection are operable per TS 4.8.4.3.a.2. The inspector observed the instantaneous trip, short time trip, and long time trip tests. All results were within the acceptance criteria.

* Bi-weekly calculation of reactor building (RB) sump leak rate setpoint (STP 114.003). TS 3.4.6.1 requires an operable RCS leakage detection system based on RB sump level. The basis for the detection system is to quickly identify an RCS leak of one GPM or greater. During the last refueling outage, a modification was completed to use the Integrated Plant Computer System (IPCS) with input from the RB sump level indicators for this RCS leak detection system. The alarm setpoint was initially set for one GPM. Due to other non-RCS leakage into the RB sump, the alarm was periodically received. The purpose of this new STP (114.003) was to quantify RB sump inleak that is not associated with unidentified RCS leakage. The IPCS setpoint is then changed to reflect this known RB sump inleakage. Since the STP is performed every two weeks or whenever it is suspected that RB sump inleakage has changed, timely verifications will be performed to

ensure that this RCS leakage detection system is capable of identifying a one GPM RCS leak.

All tests observed were performed in accordance with procedures and demonstrated acceptable results.

3. Monthly Maintenance Observation (62703)

Station maintenance activities for the safety-related systems and components listed below were observed to ascertain that they were conducted in accordance with approved procedures, regulatory guides, and industry codes or standards and in conformance with TS.

The following items were considered during this review: that limiting conditions for operation were met while components or systems were removed from service, approvals were obtained prior to initiating the work, activities were accomplished using approved procedures and were inspected as applicable, functional testing and/or calibrations were performed prior to returning components or systems to service, quality control records were maintained, activities were accomplished by qualified personnel, parts and materials used were properly certified, and radiological and fire prevention controls were implemented. Work requests were reviewed to determine the status of outstanding jobs and to ensure that priority was assigned to safety-related equipment maintenance that may affect system performance. The following maintenance activities were observed:

* Preventive maintenance on the diesel engine for fire pump XPP134B (PMTS P0152451). In addition to the lubricant and filter replacements, a partial teardown/inspection of the engine was completed in accordance with the vendor's recommended annual and biannual schedule for maintenance items.

* Troubleshooting the slow stroke time for containment purge isolation valve XVG6057 (MWR 9203043). This valve opens using air pressure and fails to the closed position by spring force. During the previous performance of STP 138.001, "Post Accident Hydrogen Removal Valve Operability Test", XVG6057 opening stroke time was 30.[illegible] seconds which exceeded the maximum opening time of 20 seconds. Since the safety function for this containment isolation valve is satisfied in the closed position, the opening stroke time does not effect valve operability. The licensee measures opening time for trending purposes. The previous closure stroke times have been consistently below the five second maximum closure time. After the air regulator outlet pressure was increased slightly, the valve's open stroke time was measured to be within the 20 second maximum time. No additional work was performed. The valve stroke times will continue to be tested quarterly which will allow detection of any future change in the open stroke time.

* Replacement of the air filters in the control room supply air handling unit XAH12B (MWR 9101004).

* Troubleshooting and repair of "A" feedwater isolation valve XVG1611A (MWR 9203136 and NCN 4414). During a routine plant tour, an operator discovered that the air accumulator pressure for XVG1611A was at 656 psig. The normal pressure range for the accumulator is 550 to 570 psig. When the high pressure condition was discovered the accumulator pump, which increases normal instrument air pressure (approximately 90 psig) to the high pressure range, was running. The pump stopped after the pressure switch, which controls the start and stop function of the pump, was tapped on. Inspection of the electrical contacts for the pressure switch revealed signs of previous arcing between the contacts and possible sticking together of the contacts. The electrical contacts were replaced and the valve operator was tested satisfactorily.

  The current capacity of the pressure switch is rated for 0.4 DC amperes. The licensee wants to duplicate the pressure switch circuit configuration to determine the actual current demand. Due to the unavailability of parts, this test is scheduled for the middle of March, 1992. If testing reveals a high current demand, the licensee plans to modify the pressure switch circuit for XVG1611A and for the other two feedwater isolations.

  The support system, which maintains the high pressure in the accumulator, is designated as non-safety related. The licensee maintains that the feedwater isolation valves are operable as long as pressure is between 500 and 600 psig. Therefore, the licensee contends the length of time (approximately one month) to determine the cause and perform possible correction action for this problem is reasonable. After reviewing this issue the inspector agrees that failure of the pressure switch will not directly effect the safety function of the valve; however, the pressure switch can impact on valve reliability.

* Replacement of actuator support bracket for component cooling water valve XVB9503B (NCN 4409). During a preventive maintenance inspection, a crack was discovered in the support bracket that attaches the Limitorque actuator to the valve gearbox. The replacement bracket that was obtained from Limitorque was made with thicker material and appeared to be designed for heavier loads than the original bracket. The licensee has been unable to determine the reason for the bracket design change. Other safety related valves with the same actuator and gearbox combination as XVB9503B were inspected. No other cracks were observed.

* Inspection of an instrument line in "A" emergency diesel generator air start system (MWR 92T0024). Due to an earlier engineering review, the licensee questioned if an orifice was installed in an air line to a pressure switch. The function of the orifice would be to prevent rapid blowdown of the air receiver due to a break in non-seismic piping. The inspection verified the orifice was present.

* Inspection of XSW1DA switchgear (MWR 92E0006). All 7.2 kV switchgear was inspected by the licensee due to the discovery of damaged conductor insulation for breaker XSW1DB #11 during routine maintenance. The insulation was being worn due to the door latch pinching the conductor whenever the door was closed. The insulation had not worn completely through and equipment operation was not effected. The inspector observed the inspection of the XSW1DA switchgear cubicles. Some minor damage to conductor insulation was noted in several of the switchgear cubicles. All deficiencies were corrected and the wiring tied off to prevent contact with the door latch.

* Inspection, cleaning and lubrication of "A" RHR pump and the "A" spray pump room cooler XAH004A (PMTS P0153034). The inspector noted a hole in the discharge ducting. The licensee indicated that a MWR would be written to repair the duct work. No other deficiencies were noted.

* Investigation and replacement of the outboard seal for "B" main feedwater booster pump, (MPP28B). The pump was secured on February [illegible] 1992, due to seal leakage from behind the lock collar and a noise that was believed to have been metal to metal rubbing. The inspector observed the removal of and the visual inspection performed to determine the failure mechanism of the subject pump seal. Disassembly of the lock collar by the licensee and vendor representative disclosed some minor pitting and carbon deposits on the seal carbon facing. If a seal runs dry the carbon may become so hot that pieces of the carbon "pull out" so that the face appears to have pitting. The observed pitting was typical of the classic type portrayed in the vendors manual. Since there was no evidence of rubout, misalignment, or shaft damage, the licensee decided to replace the lock collar with a spare and reassemble the booster pump. The carbon pitted lock collar was sent to the vendor's laboratory for further analyses and subsequent finishing.

* Investigation and repair of CCW speed switchgear room cooling fan XFN106A (NCN 4418). After it was discovered by an operator that the fan had tripped unexpectedly, the fan was restarted. However, the fan tripped again approximately 15 minutes later. After reviewing the fan breaker configuration, an electrician installed the next larger size thermal overload. Based on calculations in Electrical Maintenance Procedure (EMP) 280.001, "Sizing of Thermal Overloads", the thermal overloads could be increased without any engineering involvement. The inspector was informed by licensee management that EMP 280.001 is being reviewed and changes will be made to ensure adequate engineering oversight is provided for thermal overload changes.

* Replacement of control tubing for fire pump discharge relief valve XVR6929 (NCN 4365). On February 13, 1992, one of the three copper tubings, which are used for control of the relief valve operation, sheared at a fitting. Three similar failures occurred on October 31,

1991, December 16, 1991, and January 29, 1992. The first failure involved both a 1/2 inch copper tubing and a 1/2 inch copper pipe, while the three subsequent failures occurred only on the 1/2 inch tubing. The other 1/4 inch and 3/8 inch control tubing had no failures. In a NCN disposition, the licensee stated that the relief valve would fully open with minimal system pressure when the tubing failed, and therefore, still provide over-pressure protection. However, the inspector noted that the failed open relief valve would have significantly effected available pressure and flow in the fire service system.

Repair efforts for the first and second failure involved tubing replacement with flared end fittings like the original installation. After the third failure, Swagelock end fittings were used on the 1/2 inch copper tubing. It was not until the fourth failure of the tubing that the licensee's evaluation addressed isolating vibration which could be contributing to the repeated failures of the copper tubing. During this repair effort, braided stainless steel tubing was installed in an effort to isolate vibration from the tubing end fittings.

After reviewing the evaluations in the NCN for the various failures, the inspector questioned the thoroughness of the engineering evaluations. The cause determinations for the failures provided only limited support information. In the evaluation for the second failure, the engineer noted that valve vibration may have contributed to the failure; however, the evaluation stated that further investigation would be conducted if the tubing fails again. The inspector does not consider this evaluation adequate to rely on a future failure before initiating action to determine the actual failure cause.

The inspector also questioned the licensee's rational for declaring the fire pump operable after the fourth tubing failure. Before the braided stainless steel tubing could be obtained, new copper tubing was re-installed on the relief valve and the fire pump was declared operable. The engineering evaluation associated with this repair stated that the component was returned to the original configuration. The actions to return the fire pump to service using the copper tubing, until installation of the permanent stainless steel tubing were viewed as positive. However, adequate justification was not provided to support the fire pump operability decision. Later that day, the new stainless steel tubing was installed which satisfied any operability concerns of the fire pump. In subsequent conversation with the licensee management, the inspector emphasized the need to provide adequate justification when returning equipment to operable status on a limited basis.

The maintenance activities observed were completed using the required procedures and equipment, and achieved the desired results. The engineering support for the repeated tubing failure on the fire pump relief valve was not aggressive in determining the root cause. Also the limited basis operability determination for the fire pump was made with inadequate justification.

4. Operational Safety Verification (71707)

The inspectors conducted daily inspections in the following areas: control room staffing, access, and operator behavior; operator adherence to approved procedures, TS, and limiting conditions for operations; examination of panels containing instrumentation and other reactor protection system elements to determine that required channels are operable; and review of control room operator logs, operating orders, plant deviation reports, tagout logs, jumper logs, and tags on components to verify compliance with approved procedures.

The inspectors conducted weekly inspections in the following areas: verification of operability of selected ESF systems by valve alignment, breaker positions, condition of equipment or component(s), and operability of instrumentation and support items essential to system actuation or performance.

Plant tours included observation of general plant/equipment conditions, fire protection and preventative measures, control of activities in progress, radiation protection controls, physical security controls, plant housekeeping conditions/cleanliness, and missile hazards.

The inspectors conducted biweekly inspections in the following areas: verification review and walkdown of safety related tagout(s) in effect; observation of control room shift turnover; review of implementation of the plant problem identification system; and verification of selected portions of containment isolation lineup(s).

Selected tours were conducted on backshifts or weekends. Inspections included areas in the cable vaults, vital battery rooms, safeguards areas, emergency switchgear rooms, diesel generator rooms, control room, auxiliary building, cable penetration areas, service water intake structure, and other general plant areas. Reactor coolant system leak rates were reviewed to ensure that detected or suspected leakage from the system was recorded, investigated, and evaluated; and that appropriate actions were taken, if required. On a regular basis, RWP's were reviewed and specific work activities were monitored to assure they were being conducted per the RWP's.

No violations or deviations were identified.

5. ESF System Walkdown (71710)

The inspectors verified the operability of an ESF system by performing a walkdown of the accessible portions of the control building ventilation system. The inspectors confirmed that the licensee's system line-up procedures matched plant drawings and the as-built configuration. The inspectors looked for equipment conditions and items that might degrade performance (hangers and supports were operable, housekeeping, etc.). The inspectors verified that valves, including instrumentation isolation valves, were in proper position, power was available, and valves were locked as appropriate. The inspectors compared both local and remote position indications.

No violations or deviations were identified.

6. Onsite Follow-up of Written Reports of Nonroutine Events at Power Reactor Facilities (92700)

   (Closed) LER 90-01 indicated a potential failure of a safety function. Gilbert/Commonwealth, the architectural engineer, reported a design deficiency per 10 CFR 21; in that evaluations showed that a high energy line break (HELB) in the intermediate building would render both chilled water trains inoperable. This was due to overloading of the cooling coils that would be exposed to the steam environment. The initial corrective action isolated the cooling coils which would be exposed to the steam environment created by a HELB. These coils provide cooling to areas which contain the emergency feedwater pumps and the service water booster pumps. During the recently completed sixth refueling outage, safety-related seismically supported temperature switches were installed at the inlets of the air handling units (AHU) for these cooling coils. The function of each switch is to trip it's respective AHU fan on detection of high inlet air temperature. This modification assures that DBA heat loads imposed on the chilled water system during a HELB do not exceed the DBA design basis. This item is closed.

7. Onsite Follow-up of Events at Operating Power Reactors (93702)

   On February 21, 1992, the shift supervisor directed an operator to vent two of the main generator hydrogen coolers due to indications that the water boxes were becoming air bound. Normally operators use a ladder to access the vent valves, which are located on top of the generator. On this occasion the operator attempted to climb up the generator. In the process of climbing up, the operator broke off a 3/4 inch drain line for the "A" cooler where the line connected to the cooler water box. This caused a leak of cooling water (at approximately 60 psi) into the turbine building. The "A" cooler was subsequently isolated and the rupture drain line plugged. Approximately one minute after isolating the "A" cooler, the control room received a high generator winding temperature annunciator. The Annunciator Response Procedure (ARP) requires reducing power to 80 percent. Per the ARP, the operators began reducing power and at the same time reviewed the computer data for the generator winding temperatures. The data revealed that the winding temperatures were normal; therefore, the power reduction was terminated at 83 percent and power was subsequently restored to 100 percent. The cause of the alarm was later determined to be a difference in hydrogen gas temperature of greater than 4 degrees Fahrenheit between some of the points monitored and the average of all points monitored. This difference in temperatures was attributed to the increased flow of cooling water to the unisolated coolers.

No violations or deviations were identified.

8. Review of Nonconformance Reports (71707)

NCNs and ONOs were reviewed to verify the following: TS were complied with, corrective actions as identified in the reports were accomplished or being pursued for completion, generic items were identified and reported, and items were reported as required by the TS.

a. On February 3, 1992, ONO 92-010 was written when I&C technicians discovered that the isolation valves on the reagent gas bottle and span gas bottle for "A" post accident hydrogen analyzer were closed. These valves are required to be open. The reagent gas is used by the analyzer when measuring the hydrogen concentration of a gas sample, while the span gas is only used in calibration of the analyzer.

   The licensee's investigation was unable to determine the cause of the mispositioned isolation valves. Normally, these valves are only manipulated during the monthly surveillance test of the analyzers. However, the sequencing of steps in the surveillance test which actually use the reagent and span gas indicated that the isolation valves were open after completion of the step which requires the valves to be closed. The analyzer has an annunciator alarm set at 20 psi for low gas pressure. The licensee believes the reason this alarm was not received, while the gas bottles were isolated, was due to the pressure in the lines never bleeding down below the alarm setpoint. If the analyzer was needed for hydrogen monitoring, the licensee contends that the low pressure alarm would have been received and the mispositioned isolated valves would have been identified and repositioned.

   During their review, the licensee noted that the restoration process for re-opening the isolation valves during the surveillance test is not consistent with other activities involving valve repositioning. The licensee plans to revise the surveillance procedure to provide more uniform instruction for valve manipulation. After reviewing this event and the licensee's investigation, the inspector did not identify any other probable causes for the mispositioned valve. Also, the significance of the isolation valves being closed appears to be minor, due to the ability to quickly identify and correct the condition.

b. ONO 92-014 documented low suction pressure for "C" chill water (VU) pump when it was aligned to "A" train. At the time chemicals were being added to the VU system. The operators declared the "A" train inoperable and started the venting process to remove any air in the system. After the venting was completed and adequate level was verified in the VU expansion tank, the "A" train was declared operable.

A review of computer data trends for earlier activities identified that the expansion tank was completely drained while preparing to add chemicals. The instructions in System Operating Procedure (SOP) 501, "HVAC Chilled Water System", allows the chemical addition tank to be filled from the VU system. A caution statement in SOP 501 requires that makeup to the expansion tank should be initiated if an expansion tank low level alarm is received. During the actual fill of the chemical addition tank, the expansion tank low level alarm occurred and makeup was initiated. However, based on the expansion tank having been completely drained, it appears that the system makeup was either untimely or had an inadequate fill rate to prevent air from entering the system. The SOP does not direct securing fill of the chemical addition tank when a low expansion tank alarm is received.

The current expansion tanks for "A" and "B" train VU system were installed during the last refueling outage. It does not appear that any reviews or comparisons of the expansion tank and chemical addition tank were made to determine the impact of filling the chemical addition tank from the system. The licensee is reviewing the operation of the VU system during addition of chemical. The SOP will be revised, based on the results of the review, to ensure that adequate level is maintained in the expansion tank.

c. NCN 3645 dealt with the resolution of various VU system design problems. One of these problems involved a high energy line break issue and results in isolating four air handling units. A modification was completed during the last refueling outage which allowed returning these units to service. On January 28, 1992, disposition No. 14 to NCN 3645 was issued. Service water temperature limits related to the operation of the four air handling units were provided in the NCN disposition. At SW temperatures less than 48 degrees Fahrenheit, VU flow for two units must be isolated and with temperatures less than 44 degrees Fahrenheit, VU flow to the remaining units must be isolated.

The need to isolate VU flow to components at various SW temperatures was required to ensure adequate VU chiller performance following a safety injection actuation. Prior to installing the modification, the licensee was aware of the need to isolate VU supplied components at lower SW temperatures. However, the calculations to determine the specific SW temperatures were not performed until January, 1992. The actual instructions for operations to isolate components based on SW temperatures was issued on February 13, 1992. On the following day, VU flow to the air handling units for the SW booster pump area was isolated. A review of the logs indicated that the lowest SW temperature reached was 50 degrees Fahrenheit. While the inspector acknowledged that components were isolated prior to exceeding the SW temperature limitation, the instructions to complete these actions were not provided in a timely manner. The modification which restored the air handling units to service should have also provided any restrictions for their operation. Since the limitations were for low SW temperatures, the inspector considered the winter months the most crucial time to monitor for these conditions. Engineering stated that they had been monitoring SW temperatures to ensure that VU system restrictions were issued prior to exceeding any of the temperature limitations. The inspector considered engineering monitoring plant parameters associated with a safety system performance a poor practice.

9. Exit Interview (30703)

The inspection scope and findings were summarized on March 2, 1992, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed the inspection findings.

No dissenting comments were received from the licensee. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during the inspection.

10. Acronyms and Initialisms

AHU	Air Handling Unit
ARP	Annunciator Response Procedure
DBA	Design Basis Accident
DC	Direct Current
EMP	Electrical Maintenance Procedure
ESF	Engineered Safety Feature
GPM	Gallons Per Minute
HELB	High Energy Line Break
HVAC	Heating, Ventilation and Air Conditioning
I&C	Instrumentation and Control
IPCS	Integrated Plant Computer System
LER	Licensee Event Reports
MWR	Maintenance Work Request
NCN	Nonconformance Notice
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
ONO	Off Normal Occurrence
PMTS	Preventive Maintenance Task Sheet
PSI	Pounds Per Square Inch
PSIG	Pounds Per Square Inch Gauge
RB	Reactor Building
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RWP	Radiation Work Permits
SOP	System Operating Procedure
SPR	Special Reports
STP	Surveillance Test Procedures

SW	Service Water
TS	Technical Specifications
VAC	Voltage Alternating Current
VU	Chill Water