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

Report No.: 50-416/87-40 and 50-417/87-04

Licensee: System Energy Resources, Inc.
Jackson, MS 39205

Docket Nos.: 50-416 and 50-417 License Nos.: NPF-29 and CPPR-119

Facility Name: Grand Gulf

Inspection Conducted: December 19, 1987 - January 15, 1988

Inspectors: Leo P. Moldenhauer 2/22/88
for R. C. Butcher, Senior Resident Inspector Date Signed

Leo P. Moldenhauer 2/22/88
for J. K. Mathis, Resident Inspector Date Signed

Approved by: H C Dance 2/22/88
H. C. Dance, Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine inspection was conducted by the resident inspectors at the site in the areas of Licensee Action on Previous Enforcement Matters, Operational Safety Verification, Maintenance Observation, Surveillance Observation, ESF System Walkdown, Reportable Occurrences, Operating Reactor Events, Inspector Followup and Unresolved Items, Compliance with the ATWS Rule, 10 CFR 50.62, Refueling Activities, Startup from Refueling, Fastener Testing Per TI 5200/26, Design Changes and Modification, and Verification of Containment Integrity.

Results: One violation was identified: Failure to determine normal indicated delta pressure and set HPCS system, LPCS system, and LPCI subsystems instrumentation as required by Technical Specifications.

REPORT DETAILS

1. Licensee Employees Contacted

J. E. Cross, GGNS Site Director
C. R. Hutchinson, GGNS General Manager
R. F. Rogers, Manager, Special Projects
*A. S. McCurdy, Manager, Plant Operations
J. D. Bailey, Compliance Coordinator
M. J. Wright, Manager, Plant Support
L. F. Daughtery, Compliance Superintendent
*D. G. Cupstid, Start-up Supervisor
R. H. McAnulty, Electrical Superintendent
J. P. Dimmette, Manager, Plant Maintenance
W. P. Harris, Compliance Coordinator
*J. L. Robertson, Licensing Superintendent
L. G. Temple, I & C Superintendent
J. H. Mueller, Mechanical Superintendent
L. B. Moulder, Operations Superintendent
J. V. Parrish, Chemistry/Radiation Control Superintendent
S. M. Feith, Director, Quality Programs
*S. F. Tanner, Manager, Quality Services
*D. L. Pace, Manager, Nuclear Design

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

*Attended exit interview

2. Exit Interview (30703)

The inspection scope and findings were summarized on January 15, 1988, with those persons indicated in paragraph 1 above. The licensee did nc identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection. The licensee stated that more review is required before they agree or disagree with the inspection findings:

416/87-40-1. Violation. Failure to determine normal indicated delta pressure and set HPCS system, LPCS system and LPCI subsystems instrumentation as required by TS 4.5.1.c.2 (b). (paragraph 4)

3. Licensee Action on Previous Enforcement Matters (92702)

Not inspected this report period.

4. Operational Safety, Radiological Protection and Physical Security Verification (71707, 71709 and 71881)

The inspectors kept themselves informed on a daily basis of the overall plant status and any significant safety matters related to plant operations. Daily discussions were held with plant management and various members of the plant operating staff.

The inspectors made frequent visits to the control room such that it was visited at least daily when an inspector was on site. Observations included instrument readings, setpoints and recordings, status of operating systems, tags and clearances on equipment controls and switches, annunciator alarms, adherence to limiting conditions for operation, temporary alterations in effect, daily journals and data sheet entries, control room manning, and access controls. This inspection activity included numerous informal discussions with operators and their supervisors.

Weekly, when the inspectors were onsite, selected Engineered Safety Feature (ESF) systems were confirmed operable. The confirmation is made by verifying the following: Accessible valve flow path alignment, power supply breaker and fuse status, major component leakage, lubrication, cooling and general condition, and instrumentation.

General plant tours were conducted on at least a biweekly basis. Portions of the control building, turbine building, auxiliary building and outside areas were visited. Observations included safety related tagout verifications, shift turnover, sampling program, housekeeping and general plant conditions, fire protection equipment, control of activities in progress, problem identification systems, and containment isolation. The licensee's onsite emergency response facilities were toured to determine facility readiness.

The inspectors reviewed at least one Radiation Work Permit (RWP), observed health physics management involvement and awareness of significant plant activities, and observed plant radiation controls. The inspectors verified licensee compliance with physical security manning and access control requirements. Periodically the inspectors verified the adequacy of physical security detection and assessment aids.

On January 9, 1988 the licensee initiated Material Nonconformance Report (MNCR) 0015-88 documenting that the Low Pressure Core Spray (LPCS)/Residual Heat Removal (RHR) A line break annunciator alarmed at 80 percent power during startup from refueling outage number 2. While continuing up in power the reactor scrammed at about 93% power (see writeup in paragraph 9). Before the reactor scram, the MNCR describes several things were being done to verify the actual differential pressure was being measured. The differential pressure being measured is from the LPCS injection line to the RHR A line downstream of the injection valves which should give close pressure readings unless there is a line break in

either line within the downcomer region. Technical Specification 3.5.1, which is applicable for Operational Conditions 1, 2 and 3, action statement g requires that with an ECCS header delta P instrumentation channel inoperable, restore the inoperable channel to operable status within 72 hours or determine ECCS header delta P locally at least once per 12 hours, otherwise declare the associated ECCS inoperable. Technical Specification 4.5.1.c.2.(b) requires every 18 months performing a channel calibration of the header delta P instrumentation and verifying the setpoint of the HPCS system, LPCS system and LPCI subsystems to be 1.2 ± 0.1 psid change from the normal indicated delta P. Research by the licensee indicates that G.E. Service Information Letter (SIL) 300 issued in September 1979 and IE Circular No. 79-24 dated November 26, 1979 addressed the installation and testing of pipe break detection systems and recognized that the systems would be calibrated to read near zero delta P during cold shutdown and would possibly alarm during reactor startup. The alarm should clear when approaching rated power indicating that the instrumentation is working. This would make the pipe break detection system effective only near rated power. This guidance does not appear to be reflected in TSs. The Final Safety Analysis Report has a brief description of the HPCS and LPCS/RHR A line break detection systems only. High Pressure Core Spray is described in paragraph 7.3.1.1.1.3.11.2 and LPCS/RHR A is described in paragraph 7.3.1.1.1.5.11.2. The RHR B/RHR C line break detection system is not mentioned. The licensee has not determined what is the normal delta P for the LPCS/RHR A lines. The instrumentation setpoint as specified in Surveillance Procedure 06-IC-1E31-R-0021, Revision 23, LPCS/RHR/HPCS Header Differential Pressure Calibration, was based on original calculations. Technical Specification 4.5.1.c.2 (b) requires that every 18 months a channel calibration of the header delta P instrumentation setpoints be verified for the HPCS system, LPCS system and LPCI subsystems to be 1.2 ± 0.1 psid from the normal indicated delta P. Failure to determine the normal indicated delta P and verify the HPCS system, LPCS system and LPCI subsystems setpoints to be within 1.2 ± 0.1 psid of normal is a violation 416/87-40-01. The NRC Project Manager was requested to determine an interpretation of the meaning of normal indicated delta pressure in TS 4.5.1.c.2(b). He stated the normal indicated delta pressure should be determined while at normal rated power. This supports the previously discussed SIL and IE Circular.

5. Maintenance Observation (62703)

During the report period, the inspectors observed portions of the maintenance activities listed below. The observations included a review of the Maintenance Work Orders (MWOs) and other related documents for adequacy, adherence to procedure, proper tagouts, adherence to technical specifications, radiological controls, observation of all or part of the actual work and/or retesting in progress, specified retest requirements, and adherence to the appropriate quality controls.

MWO # I80322 Rework loop controls; replace potentiometer module and pushbutton switch modules on P680 panel.

MWO # M80346 Open condenser, perform a leakage inspection and plug tubes that are leaking.

No violations or deviations were identified.

6. Surveillance Observation (61726)

The inspectors observed the performance of portions of the surveillances listed below. The observation included a review of the procedure for technical adequacy, conformance to technical specifications, verification of test instrument calibration, observation of all or part of the actual surveillances, removal from service and return to service of the system or components affected, and review of the data for acceptability based upon the acceptance criteria.

06-OP-1P41-Q-0004, Revision 24, Standby Service Water Loop A Valve & Pump Operability Test.

06-RE-SC11-V-0402, Revision 26, Control Rod Scram Testing.

06-OP-1E51-R-0005, Revision 26, RCIC Pump Low Pressure Flow Verification Test

06-IC-1B21-M-0014, Revision 21, Safety Relief Valve Tail Pipe Pressure Switch Function Test.

06-ME-1M10-R-0003, Revision 25, Drywell Bypass Leakage Rate.

06-OP-1E51-Q-0002, Revision 28, RCIC System Valve Operability Test.

06-IC-1C71-R-0013, Revision 25, Reactor Mode Switch Interlocks Functional Test.

06-OP-1B21-R-0002, Revision 26, ADS/SRV Valve Operability.

06-ME-1M23-V-0001, Revision 28, Containment and Drywell Airlock Seal Leak Test.

No violations or deviations were identified.

7. Engineered Safety Features System Walkdown (71710)

A complete walkdown was conducted on the accessible portions of the Standby Gas Treatment System. The walkdown consisted of an inspection and verification, where possible, of the required system valve alignment, including valve power available and valve locking where required, instrumentation valved in and functioning; electrical and instrumentation cabinets free from debris, loose materials, jumpers and evidence of rodents, and system free from other degrading conditions.

No violations or deviations were identified.

8. Reportable Occurrences (90712 & 92700)

The below listed event reports were reviewed to determine if the information provided met the NRC reporting requirements. The determination included adequacy of event description and corrective action taken or planned, existence of potential generic problems and the relative safety significance of each event. Additional inplant reviews and discussions with plant personnel as appropriate were conducted for the reports indicated by an asterisk. The event reports were reviewed using the guidance of the general policy and procedure for NRC enforcement actions, regarding licensee identified violations.

The following License Event Reports (LERs) are closed.

LER No.	Event Date	Event
*87-019	November 17, 1987	Heavy Load Transported Over New Fuel In The Upper Containment Fuel Pool.
*87-005	April 15, 1987	Three Main Steam Line Radiation Monitors Exceed Technical Specification Trip Limit.
*87-020	November 19, 1987	Shutdown Cooling Isolation Due To a Blown Fuse.
87-022	December 7, 1987	RWCU Isolation Due To a Blown Fuse.

The event of LER 87-019 was discussed in Inspection Report 416/87-35.

The event of LER 87-005 is discussed in paragraph 13 of this report.

The event of LER 87-020 was discussed in Inspection Report 416/87-35.

No violations or deviations were identified.

9. Operating Reactor Events (93702)

The inspectors reviewed activities associated with the below listed reactor events. The review included determination of cause, safety significance, performance of personnel and systems, and corrective action. The inspectors examined instrument recordings, computer printouts, operations journal entries, scram reports and had discussions with operations, maintenance and engineering support personnel as appropriate.

On December 19, 1987 at approximately 8:48 p.m. during performance of I&C Surveillance procedure 06-IC-1B21-R-0004-1, Main Steam Line Isolation Valve Closure Calibration, a full scram was received. The reactor was in

cold shutdown (refueling mode) with all rods in. During the surveillance upon closing Main Steam Isolation Valve (MSIV) F022A a full scram occurred instead of the expected 1/2 scram in Division 2. Upon investigation by the licensee it was found that the fuse (1C71-F11A) reinstalled in step 5.29 of data sheet III for MSIV F022A was signed off by one I&C technician and verified by another I&C technician as to being installed. The licensee determined that fuse 1C71-F11A popped out of its holder which would give a 1/2 scram for Reactor Protection System (RPS) Division 1. In preparation for closing of MSIV F022A, fuse C71-F11B was pulled out in step 5.30. This set up conditions for a 1/2 scram in RPS Division 2 upon the closing of MSIV F022A. Therefore, when F022A was closed a full scram occurred. Incident Report (IR) Number 87-12-14 was written to document this event.

On January 10, 1988 at 3:08 p.m. the reactor scrammed from 93.5 percent reactor power. Investigation by the licensee determined that a phase differential from the B main transformer initiated a turbine trip which initiated a reactor scram. No Emergency Core Cooling Systems (ECCSs) injected and water level decreased to approximately -2.5 inches. Reactor pressure reached an indicated 1109 psig initiating an ATWS recirculation pump trip. No safety-relief valves lifted. The phase differential fault was caused by the failure of the B transformer. Upon investigating the transformer problem the licensee was forced to stay down for at least 4 days after scramming to replace the failed transformer and bring on line the spare transformer. This activity is covered by the following MWO packages: E80383, E80384, E80427, E62703, E72878, E80375, E74336, E80326, and E80276.

The inspectors followed the replacement of the spare transformer. The spare transformer was already installed adjacent to the normal 3 main transformers and only required hardware type changes to tie into the existing generator leads. The licensee plans to use one of the 3 transformers from unit 2 as a spare by removing the failed transformer and installing the unit 2 transformer in its place. Limiting Condition for Operation (LCO) 88-035 was initiated on three low low set valves whose proper operation was originally questioned. It now appears that the low low set logic for Channel A and Channel B trip units tripped but corresponding channels E and F trip units did not trip so no safety relief valves lifted. This indicated proper relief valve operation and the LCO was lifted. The reactor was taken critical on January 13, 1988 at 5:45 p.m. in preparation for connecting onto the grid. The reactor was synchronized to the grid at 9:53 p.m. on January 15, 1988.

On January 11, 1988 at 7:15 a.m. a reactor scram occurred due to low water level. The reactor was in hot shutdown at 310 psig at the time of the event. Operators noticed the reactor vessel water level was increasing and the set pressure was decreasing causing the bypass valve to open. Reactor pressure decreased to approximately 270 psig before the operators could manually stop the set pressure decrease. Reactor water level then decreased to approximately 9 inches resulting in a reactor vessel low

water level scram. This incident was documented by the licensee in Incident Report Number 88-1-6. The licensee initiated Maintenance Work Order (MWO) I803322 to rework loop controls and to replace potentiometer module and pushbutton switches on P680 panel.

No violations or deviations were identified.

10. Inspector Followup and Unresolved Items (92701)

(Closed) Inspector Followup Item 416/87-22-03. The licensee issued Licensee Event Report (LER) 87-009-01 clarifying the use of an existing bypass switch which will allow bypassing the Reactor Water Cleanup (RWCU) isolation logic. System Operating Instruction (SOI) 04-1-01-G33-1 has been revised to delete the reference to an anticipated group 8 isolation. An engineering review is being performed to determine the amount of time the present 45 second automatic bypass time delay can be extended and the licensee will submit a change request when an allowable time limit is determined.

11. Compliance With the ATWS Rule, 10 CFR 50.62 (25020)

The inspection requirements of TI 2500/20 were addressed previously in Inspection Reports 416/87-29 and 416/87-35. During this inspection period the inspectors witnessed the testing of the work performed by DCP 85/4053. The testing of the modifications done to the Standby Liquid Control System to meet 10 CFR 50.62 acceptance criteria was controlled by Modification Special Test Instruction (MSTI) 1C41-87-002-0-S. The test was divided into the following sections.

Section 7.1 of test MSTI 1C41-87-002-0-S flushed the SLC system as required to ensure only reactor grade water will be pumped to the reactor.

Section 7.2 stroked the valve 1C41F008, in which modifications were made during this outage, and compared remote indication with actual position.

Section 7.3 demonstrated the capability of the SLCS to deliver the Boron solution to the reactor at the required two pump flow rate without exceeding the calculated pump operating pressure. Both pumps was operated in the normal injection lineup.

Section 7.4 demonstrated that the required discharge pressure was enveloped by the 1300 psig Technical Specification discharge pressure. Pump discharge pressure of at least 1300 psig was achieved by throttling pump discharge valves and flow was verified to be at least 82.4 gpm with both SLCS pumps operating.

Section 7.5 verified that each pump produced a flowrate of at least 41.2 gpm with at least 1300 psig discharge pressure.

The portions of MSTI 1C41-87-002-0-S witnessed by the inspector consisted of pump flow capacity test for SLC pump A and B, SLC pump A and B were simultaneously started by closing both the installed test switches on panel 1H22-P011. Throttle valve 1C41-F221 was slowly closed to achieve a stable pressure greater than or equal to 1300 psig. Pump discharge relief valves (1C41-F-029A & B) were then verified to have not lifted. The combine discharge flow of SLC pump A and B were measured to be 82.5 gpm.

In addition to the combined pump flow capacity test, the inspector witnessed the single pump flow test for both the A and B pumps. The recorded pump discharge flows for pump A and B were 44 gpm and 46 gpm respectively. The remaining portions of MSTI 1C41-87-0002-0-S were reviewed for conformance to the acceptance criteria.

12. Fastener Testing To Determine Conformance With Applicable Material Specifications (25026) - Unit 2 Only

This inspection was conducted on Unit 2 per Temporary Instruction 2500/26 to ensure fasteners selected in response to NRC Bulletin 87-02 are representative of installed fasteners and that suspect fasteners are selected for testing. Ten non-safety related studs, bolts and/or capscrews; ten non-safety related nuts, ten safety related studs, bolts and/or capscrews and ten safety related nuts were to be selected from stock for testing. The inspector participated in the licensee's selection of samples required by action item 2 of Bulletin 87-02 for Unit 2.

The sample selected was based, in part, from the types and grades of fasteners utilized on Unit 2 to date and the test laboratory (Wyle) requirements that the fasteners had to be 1/2 inch diameter or larger and a minimum length of 3 x the diameter. All fasteners were procured as safety related except the non-safety related bolting as identified in the sample was supplied as part of the non-safety related structural steel purchased as part of the contract for erection of the turbine building. From interviews with licensee personnel the following proportion of use of fasteners was determined:

	Type and Grade	Percent Use (approx)
Nuts:	SA-307, Gr. A	5
	SA-194, Gr. 7	5
	#SA-194, Gr. 2H	45
	SA-307, Gr. B	15
	#A -325	25
	A -563, Gr. D	5
Bolts:	SA-307, Gr. A	5
&	SA-307, Gr. B	15
Studs	#A -325	30
	#A -490	10
	SA-193, Gr. B7	40

Also procured as non-safety related for turbine building erection.

Based on the above figures, the following fastener sampling was agreed to:

SAFETY RELATED BOLTS/STUDS

SAMPLE I.D.	ITEM DESCRIPTION	HEAD MARKING
GGNS-U2-1	1 1/8" x 6 1/2" Stud Bolt SA193 B7	B7, T, FX65
GGNS-U2-2	7/8" x 5 1/2" Stud Bolt SA193 B7	B7, T, LA73
GGNS-U2-3	5/8" x4 3/4" Stud Bolt SA193 B7	B7, C, K2
GGNS U2-4	1/2" x 5 1/2" Stud Bolt SA193 B7	B7, C, C2
GGNS U2-5	1/2" x 4 1/4" HHH Bolt SA307-B	TB, 1Q39
GGNS U2-6	5/8" x 3 1/4" HHH Bolt SA307-B	TB, 1F15
GGNS U2-7	1" x 4 1/2" HHH Bolt SA 307-B	TB, HD40
GGNS U2-8	1" x 4 1/4" HHH Bolt A325	RBW, A325
GGNS U2-9	1" x 8 1/2" HHH Bolt A325	TB, A325
GGNS U2-10	7/8" x 5" HHH Bolt A490	TB, A490
GGNS U2-11	1/2" x 3" HHH Bolt A307 GR-A	TB, IQ53

SAFETY RELATED NUTS

SAMPLE I.D.	ITEM DESCRIPTION	HEAD MARKING
GGNS-U2-1A	1 1/8" HH Nut SA194 2H	2HT, DZ11
GGNS-U2-2A	7/8" HH Nut SA194 2H	2HK, C4
GGNS-U2-3A	5/8" HH Nut SA194-2H	2HU, K6
GGNS-U2-4A	1/2" HH Nut SA194-2H	2HT, DZ53
GGNS-U2-5A	1/2" HH Nut SA307-B	T, HD73
GGNS-U2-6A	5/8" HH Nut SA307-B	T, 1F18
GGNS-U2-7A	1" HH Nut SA307-B	T, HD46
GGNS-U2-8A	A" HH Nut A325	Three Circ. Lines
GGNS-U2-9A	1" HH Nut A325	Three Circ. Lines
GGNS-U2-10A	7/8" HH Nut SA194-2H	2H, S, V,
GGNS-U2-11A	1/2" HH Nut A 307 GR-A	T, IQ54
GGNS-U2-12A	1 1/8" HH Nut SA 194 GR-7	C, Y1, 01, 7
GGNS-U2-13A	2 3/4" HH Nut A563 GR-D	T, D

NON SAFETY RELATED BOLTS

SAMPLE I.D.	ITEM DESCRIPTION	HEAD MARKING
GGNS-U2-A (2)	3/4" x 3 1/4" HHH Bolts A490	A490,SBC
GGNS-U2-B (2)	3/4" x 3 1/4" HHH Bolts A325	A325,SB 1
GGNS-U2-C (2)	1" x 5" HHH Bolt A325	A325,RBW
GGNS-U2-D	1" x 5" HHH Bolt A325	A325,RBW
GGNS-U2-E	3/4" x 3 1/4" HHH Bolt A490	A490, SB
GGNS-U2-F (2)	3/4" x 3" HHH Bolt A490	A490, SB

NON SAFETY RELATED NUTS

SAMPLE I.D.	ITEM DESCRIPTION	HEAD MARKING
GGNS-U2-A-1 (2)	3/4" HH Nuts A194-2H	P2H
GGNS-U2-B-1 (2)	3/4" HH Nuts A325	Three Circ. Lines
GGNS-U2-C1 (2)	1" HH Nut A325	Three Circ. Lines
GGNS-U2-D1	1" HH Nut A194-2H	Three Circ. Lines
GGNS-U2-E1	3/4" HH Nuts A325-2H	2H, P
GGNS-U2-F1 (2)	3/4" HH Nut A194-2H	2H, P

The inspectors verified that each fastener was tagged with identifying sample number, description, and heat code/material type. In addition, the inspector verified that each sample was put in a separate plastic bag along with the NRC supplied Fastener Testing Data Sheets.

13. Design, Design Changes and Modifications (37700)

The inspectors reviewed the following design change for conformance with the requirements of TS and 10 CFR 50.59. Design Change Implementation Package (DCIP) 84/0160, Revision 0, replaced the existing INMAC Main Steam Line (MSL) log radiation monitors with NUMAC log radiation monitors. Licensee Event Report 87-005-02 documented the problem the licensee was experiencing with an instrument drift problem with the existing equipment. Technical Specification 3.3.2-2.2.b requires the MSL high radiation trip setpoints to be set less than 3 times full power background with an allowable value of 3.6 times full power background. The instruments provide a reactor scram signal, a mechanical vacuum pump trip signal and an MSL isolation signal if the high radiation signal is reached in a one out of two taken twice logic. The inspectors verified the following: a) The licensee reviewed and approved the design changes in accordance with TS and approved procedures. b) The design change had been properly documented and an approved evaluation per 10 CFR 50.59 was performed. c) Design change retests were accomplished within procedural time requirements and results were satisfactory. d) The operating procedures were modified to reflect the design change. e) The new MSL radiation monitors were fully operable and operators were familiar with taking data for operating logs.

The following maintenance work packages were reviewed to determine if they included applicable specifications, guides and codes covering the work; identification of required inspections or retests and QA/QC requirements.

MWP 87/1239	REWORK PANEL H13-P669
MWP 87/1240	REWORK PANEL H13-P671
MWP 87/1241	REWORK PANEL H13-P670
MWP 87/1242	REWORK PANEL H13-P672

No violations or deviations were identified.

14. Verification of Containment Integrity (61715)

The inspectors verified that the licensee established primary containment integrity following cold shutdown for the refueling outage. Ten primary containment penetrations were verified to be correctly aligned by local observation where available and by remote indication. The primary containment upper and lower air lock seal leak tests were witnessed by the inspectors and the Standby Gas Treatment System was walked down to verify operability. See paragraph 6 for the containment airlock seal leak test and paragraph 7 for the Standby Gas Treatment System walkdown.

No violations or deviations were identified.

15. Refueling Activity (60710)

The refueling outage for cycle two was previously reported in Inspection Reports 416/87-29 and 416/87-35. Reactor vessel reassembly started on December 20, 1987. The reactor vessel head tensioning was completed on December 22, 1987 in accordance with the procedure 06-OP-1B13-V-0001. Following the head tensioning the reactor mode switch was placed in shutdown. The inspector verified that surveillances required to be completed prior to entering shutdown mode of operation were completed.

On December 29, 1987, the inspectors witnessed portions of procedure 06-ME-1M10-R-0003, Revision 25, Drywell Bypass Leakage Rate, performed by the licensee. The test determines the drywell leakage with the drywell pressurized to approximately 3 psid and verifies that the drywell bypass leakage is less than or equal to 3500 scfm. This test is required to be performed at least once per 18 months in accordance with T.S. 4.6.2.2. The test result for the drywell leakage was approximately 1500 scfm. The inspector calculated the leakage independent of the licensee and got the same value. There were no deficiencies associated with this test.

No violations or deviations were identified.

16. Plant Startup From Refueling (71711)

Startup for Unit 1, Cycle 3 started on January 3, 1988. The reactor mode switch was placed to startup at 5:30 p.m. on January 3, 1988. The controlling procedure for startup, Integrated Operating Instruction (IOI) 03-1-01-1, was reviewed by the inspectors to verify that startup was being conducted in accordance with technically sound and approved procedures and to assure that they had been revised to reflect changes made to the facility and to the start-up testing program. The following precritical test were witnessed by the inspector:

a. Control Rod Scram Testing (06-RE-SC11-V-0402)
b. Reactor Mode Switch Interlocks Functional Test (06-IC-1C71-R-0013)

Criticality for cycle 3 was achieved on group 2, gang 6 position 26 at 3:54 a.m. on January 4, 1988. The reactor coolant temperature recorded was 146.25°F. The calculated Shutdown Margin was determined to be 1.586 (%Δ K/K). The inspector verified that criticality was achieved in a controlled manner.

No violations or deviations were identified.