ENTERGY

Entergy Operations, Inc.
P.O. Box 756
Port Gibson, MS 39150
Tel 601 437 6408

W. T. Cottle
Vice President
Operations
Grand Gulf Nuclear Station

May 14, 1992

U.S. Nuclear Regulatory Commission
Mail Station P1-137
Washington, D.C. 20555

Attention: Document Control Desk

SUBJECT: Grand Gulf Nuclear Station
Unit 1
Docket No. 50-416
License No. NPF-29
Misidentified Valve Causes Violation of Tech Spec 3.0.3
LER 92-004-00

GNRO-92/00056

Gentlemen:

Attached is Licensee Event Report (LER) 92-004 which is a final report.

Yours truly,

for

WTC/BAB/cg
attachment
cc: Mr. D. C. Hintz (w/a)
Mr. J. L. Mathis (w/a)
Mr. R. B. McGehee (w/a)
Mr. N. S. Reynolds (w/a)
Mr. H. L. Thomas (w/o)

Mr. Stewart D. Ebneter (w/a)
Regional Administrator
U.S. Nuclear Regulatory Commission
Region II
101 Marietta St., N.W., Suite 2900
Atlanta, Georgia 30323

Mr. P. W. O'Connor, Project Manager (w/a)
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Mail Stop 13H3
Washington, D.C. 20555

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NRC Form 366 (9-83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/88

LICENSEE EVENT REPORT (LER)

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TITLE (4): Misidentified Valve Causes Violation of Tech Spec 3.0.3

EVENT DATE (5) Month	Day	Year	LER NUMBER (6) Year	Sequential Number	Revision Number	REPORT DATE (7) Month	Day	Year	OTHER FACILITIES INVOLVED (8) Facility Names	Docket Number(s)
0 4	1 4	9 2	9 2	0 0 4	0 0	0 5	1 4	9 2		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
20.405(a)(1)(iii)	X 50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Area Code)
Bruce A. Burke / Licensing Engineer	6 0 1 4 3 7 - 6 3 3 3

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

YES (If yes, complete EXPECTED SUBMISSION DATE) X NO

EXPECTED SUBMISSION DATE (15): MONTH DAY YEAR

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

Station personnel were performing local leak rate testing (LLRT) of the standby service water (SSW) system containment isolation valves for drywell purge system compressor coolers. An operator had closed a valve in the other division, not realizing that he had selected the wrong valve. This resulted in both divisions of drywell purge system (an engineered safety feature system) being inoperable concurrently for approximately 13 hours. This was nonconforming with Technical Specification 3.6.7.3. Actions of Technical Specification 3.0.3 were not accomplished due to the unknown condition.

The cause of this event was incomplete component designation stencilled on the valve. The operator thought that P41F244A was P41F244B. The operator observed from the floor the stencil painted on the valve body indicating it as P41F244. This agreed with a component locator aid and reinforced the error. The operator failed to verify the unique label on the valve. Corrective actions resulting from this event include changes to the operator training program and walkdown of painted stencils to determine accurate component designations. The event was disseminated to plant personnel.

The drywell purge compressors cannot meet long term operation requirements without adequate cooling water flow. Based on analysis, complete absence of drywell compressor purge flow would have an insignificant overall effect on the concentration of hydrogen in the drywell and on the drywell response provided that the drywell hydrogen ignition system is in service. The drywell hydrogen ignition system was operable for the entire period that both drywell purge compressors were inoperable. Safety and health of the general public were not compromised by this event.

A. **Reportable Occurrence**

On April 14, 1992 at approximately 0530 CST, plant operators discovered that both divisions of drywell purge system [BB] had been inoperable. The drywell purge system is a subsystem of the combustible gas control system [BB]. This condition is prohibited by Grand Gulf Nuclear Station (GGNS) Technical Specification 3.6.7.3. The actions specified by Technical Specification 3.0.3 were not accomplished in the required time limit. This event is reportable per 10 CFR 50.73(a)(2)(i)(b).

B. **Initial Conditions**

The plant was in Operational Condition 1 at full power with reactor water at approximately 532 degrees F and 1029 psig. Station personnel were preparing to perform local leak rate testing (LLRT) of the standby service water (SSW) system [BI] containment isolation valves for the Division 2 drywell purge system compressor coolers.

C. **Description of Event**

On April 9, 1992 at approximately 0600 CST, cooling water to Division 2 drywell purge compressor was isolated to perform type C LLRT of its containment isolation valves. During the test, difficulty was experienced with the test equipment and the valve lineup was changed to expand the test boundary. A utility nonlicensed operator was dispatched with the required lineup at approximately 1800 CST. The operator was expected to verify that valve P41F244B was closed, initial the valve lineup procedure data sheet, and then proceed to containment to open a vent valve.

A component locator aid was posted outside the room. This is distributed as information by the Health Physics (HP) group and used by station personnel in locating the correct area of the room to find a component, thereby saving time and reducing exposure. The HP component locator aid listed and designated valve P41F244 (not P41F244A or P41F244B). The valve was located in an upper region of the room and accessed via ladder. The valve had P41F244 stenciled on the valve body which was visible from the floor. The operator closed valve P41F244A, not realizing that he had selected the wrong valve. LLRT of containment isolation valves for Division 2 drywell purge compressor cooling water was completed at 0700 hours April 10, 1992. P41F244B was reopened as part of the division 2 restoration.

The error was discovered on April 14, 1992 while performing valve lineup for LLRT of containment isolation valves for Division 1 drywell purge compressor cooling water. P41F244A was found in the closed position contrary to the system operating instruction. With valve P41F244A closed, Division 1 drywell purge system was inoperable. This was concurrent with Division 2 drywell purge system being inoperable to facilitate LLRT. P41F244A had

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

been closed for approximately 13 hours while Division 2 drywell purge system was inoperable. Both divisions were inoperable. This was nonconforming with Technical Specification 3.6.7.3. Therefore, the plant was in Technical Specification 3.0.3 for approximately 13 hours.

D. **Apparent Cause**

The cause of this event was the incomplete component designation stencilled on the valve. Components were stencilled in an uncontrolled process as part of the painting program at the plant. The process did not assure correct identification and designations.

A contributing factor was inattention to detail by the operator. The operator failed to verify the unique label on the valve (which indicated the component correctly). Personnel are expected to check the unique component label when identifying or manipulating components or equipment. Although the individual had discussed the task and valve location in the control room with the control room supervisor before embarking on the duty, inadequate job briefing also contributed to the event. The operator found the valve open and proceeded to close it when he was to verify that the valve position was closed.

The operator thought that P41F244 was P41F244B and proceeded to close the valve, thereby isolating SSW cooling water to the Division 1 drywell purge compressor. The operator observed from the floor the stencil painted on the valve body indicating it as P41F244. This detail agreed with the component locator aid and reinforced the error. In addition, P41F244B was not shown on the HP component locator aid even though it is in the same room.

E. **Corrective Action(s)**

Corrective actions resulting from this event include a 100% walkdown verification of painted stencils on components in the power block and correction of all incorrect or incomplete stencils. Stenciling has been removed from the uncontrolled GGNS painting program and is being incorporated into the Operations Component Identification and Labeling Program. The incomplete stencil on valve P41F244B has been corrected. The HP locator aid has also been revised to correctly designate the valves.

Immediate training was given to operators which emphasized the importance of the expected actions and results of self-verification while manipulating plant components and expected actions by operators when incomplete or incorrect labeling is discovered in the plant. Operations supervisors were trained on the elements of complete pre-job briefings and informed of the event.

Initial operator training program will be revised to emphasize the component labeling program, concepts of human error, and proper self-verification techniques. This will be completed prior to commencing the next nonlicensed operator class.

The event was disseminated to plant personnel. Proper performance of self-verification and proper use of HP component locator aids were stressed to plant staff.

F. **Safety Assessment**

Cooling water from the SSW system is provided to maintain the compressor oil temperature below 200 degrees F. As with other oil-cooled rotating machinery, operation above the design temperature limit will result in overheating and rapid deterioration of compressor performance. Drywell purge compressors will operate at design performance levels for about ten minutes without cooling water. Using test data, these compressors may actually run approximately 23.5 minutes prior to overheating. Therefore, the drywell purge compressors cannot meet long term operation requirements without adequate cooling water flow.

To control the accumulation of hydrogen in the drywell, GGNS is equipped with two safety-related, 100% redundant and diverse subsystems of the combustible gas control system (CGCS): (i) drywell purge system which operates in conjunction with the containment hydrogen recombiners and igniters; and (ii) drywell hydrogen igniters [BB]. Each subsystem also features redundant divisions. The drywell hydrogen ignition system was operable for the entire period that both drywell purge compressors were inoperable.

The required safety function of the drywell purge compressors is to purge noncondensibles from the drywell into the larger containment volume post-LOCA. These compressors are not required for drywell vacuum relief or drywell gas space mixing.

As a result of the accident at TMI-2, degraded core accidents resulting in the generation of very large amounts of hydrogen became an issue. To address the particular sensitivity of BWRs with Mark III containments to the new degraded core hydrogen issues, a Mark III containment Hydrogen Control Owners Group (HCOG) was formed in May 1981. This group was composed of the utilities operating GGNS, River Bend Station, Perry Nuclear Power Plant, and Clinton Power Station. Pursuant to the additional hydrogen control requirements being adopted at that time and the recognition that existing CGCS would not be capable of effectively controlling significant amounts of hydrogen, each Mark III plant installed a hydrogen ignition system. Subsequent to the degraded core issues, more conservative design requirements applicable to Mark III plants were adopted in January 1985 by an amendment to the hydrogen rule contained in 10 CFR 50.44. The amended rule required that a hydrogen control system be provided and that the system be capable of accommodating, without loss of containment structural integrity, the amount of hydrogen generated from a metal-water reaction of up to 75% of the active fuel cladding. During this period, the primary focus of the HCOG efforts was to collectively perform testing and analyses to demonstrate the effectiveness and reliability of the hydrogen ignition systems in meeting the amended requirements.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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A significant amount of generic testing and analyses were performed in support of plant unique analyses as a part of the HCOG program. The results of these efforts were formally submitted to USNRC by HCOG in a topical report dated February 23, 1987. Based on USNRC review (dated August 1990), the topical report was deemed acceptable for referencing in licensee analyses of hydrogen control systems. Each HCOG member also provided plant-specific submittals. The USNRC staff's interim evaluation of the GGNS initial plant response is documented in Supplements 3 and 5 to GGNS Safety Evaluation Report (i.e., NUREG-0831). The final GGNS submittal is still pending.

Generic Mark III containment testing of hydrogen combustion responses was performed using model test facilities. The test results demonstrated the capabilities of the hydrogen ignition system in limiting the concentration of hydrogen to below detonable levels from the significant amounts of hydrogen required by the amended regulations.

Analyses were also performed by HCOG using the CLASIX-3 computer code to evaluate the Mark III containment and drywell responses to hydrogen generation events. A number of sensitivity analyses were run for each scenario. Although all cases included the CGCS drywell purge compressor flow as a matter of modeling accuracy, several cases were run considering the effects of operating one versus two compressors. These sensitivity analyses concluded that the only significant effect of the increased CGCS flow in the drywell is to slightly lower the temperature (i.e., less than 10 degrees F difference) and to increase the oxygen concentration. The temperature reduction was due to the higher flow of cooler gas from the containment into the drywell and not to a reduction in hydrogen combustion. Based on this analysis, it can be concluded that the complete absence of a drywell compressor purge flow would have an insignificant overall effect on the concentration of hydrogen in the drywell and on the drywell response provided that the drywell hydrogen ignition system is in service.

Additionally, in recent meetings with USNRC Office of Nuclear Reactor Regulations and the owners groups involving the improved technical specification project, the USNRC staff has agreed that the complete loss of normal post-LOCA hydrogen control (i.e., recombiners and/or drywell purge) can be allowed for seven days provided that the hydrogen ignition system is operable. While this must be implemented on a plant-specific basis, this provides information on USNRC perception of diversity of CGCS and hydrogen control.

Safety and health of the general public were not affected by this event.

G. Additional Information

Energy Industry Identification System (EIIS) codes are identified in the text within brackets [ ].