MISSISSIPPI POWER & LIGHT COMPANY
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March 29, 1985

NUCLEAR LICENSING & SAFETY DEPARTMENT

U. S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation
Washington, D. C. 20555

Attention: Mr. Harold R. Denton, Director

Dear Mr. Denton:

SUBJECT: Grand Gulf Nuclear Station
Units 1 and 2
Docket Nos. 50-416 and 50-417
License No. NPF-29
File: 0260/0755/6450
Additional Information on NUREG-0737
Item II.D.1
AECM-85/0099

Enclosed please find Mississippi Power & Light's response to your request for additional information dated December 12, 1984. This request for information concerned a report submitted to the NRC by the BWR Owners Group in response to NUREG-0737 Item II.D.1 entitled "Analysis of Generic BWR Safety Relief Valve Operability" (NEDE-24988-P). Attachment 1 to this letter describes the basis for application of the BWR Owners Group test results to Grand Gulf Nuclear Station (GGNS) by responding to NRC questions one through six. Attachment 2 provides actual Wyle Laboratory test results for the GGNS valve which was tested.

This response completes Mississippi Power & Light's efforts on this issue. Should you have any further questions regarding this item please advise.

Yours truly,

SH Hobbs
for L. F. Dale
Director

ARR/SHH:rw
Attachments

cc: (See Next Page)

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NRC QUESTION 1

The BWR/GE test program utilized a "rams head" discharge pipe configuration. Most plants utilize a "tee" quencher configuration at the end of the discharge line. Describe the discharge pipe configuration used at your plant and compare the anticipated loads in this configuration to the measured loads in the test program. Discuss the impact of any differences in loads on valve operability.

RESPONSE TO QUESTION 1

The safety/relief valve (SRV) discharge piping configuration at Grand Gulf Nuclear Station (GGNS) utilizes an "X" quencher at the discharge pipe exit. The average length of the 20 SRV discharge lines is 94 feet and the submergence depth in the suppression pool is approximately 13.8 feet. The SRV test program utilized a rams head at the discharge pipe exit, a pipe length of 112 feet and a submergence depth of approximately 13 feet. Loads on valve internals during the test program are larger than loads on valve internals in the GGNS configuration for the following reasons:

1. No dynamic mechanical load originating at the "X" quencher is transmitted to the valve in the GGNS configuration because there is an anchor point between the valve and the "X" quencher.

2. The length of the SRV discharge line piping between the SRV and the first elbow in the test facility was about the same length as in the GGNS configuration (12 feet in the test facility, 12.1 feet in the the GGNS configuration). However, unlike the rigid test configuration, GGNS has ball joints in the piping spool between the SRV and the first anchor point which will rotate similarly to a hinge in response to any externally applied moment. Hence, the mechanical load on the GGNS SRV will be much lower than that on the test facility valve.

3. Dynamic hydraulic loads (backpressure) are experienced by the valve internals in the GGNS configuration. The backpressure loads may be either (i) transient backpressures occurring during valve actuation, or (ii) steady-state backpressures occurring during steady-state flow following valve actuation.

   (a) The key parameters affecting the transient backpressures are the fluid pressure upstream of the valve, the valve opening time, the fluid inertia in the submerged safety/relief valve discharge line (SRVDL) and the SRVDL air volume. Transient backpressures increase with higher upstream pressure, shorter valve opening times, greater line submergence and smaller SRVDL air volume. The transient backpressure in the test program was maximized by utilizing an orifice plate in the SRVDL to create a 35-40% backpressure condition on the valve internals, body bowl and discharge flange. This induced backpressure simulated the maximum backpressure anticipated in the GGNS SRVDLs. The maximum transient backpressure occurs with high pressure steam flow conditions. The transient backpressure for the alternate shutdown cooling mode of operation is always much less than the design for steam flow conditions because of the lower upstream pressure and the longer valve opening time.

(b) The steady-state backpressure in the test program was maximized by utilizing an orifice plate in the SRVDL above the water level and before the rams head. The orifice was sized to produce a backpressure equal to or greater than that calculated for any of the GGNS SRVDLs.

The differences in the line configurations between GGNS and the test program as discussed above result in loads on the valve internals for the test facility which bound the actual GGNS loads. An additional consideration in the selection of the rams head for the test facility was to allow more direct measurement of the thrust load in the final pipe segment. Utilization of a "X" quencher in the test program would have required quencher supports that would unnecessarily obscure accurate measurement of the pipe thrust loads. For the reasons stated above, differences between the SRVDL configurations in GGNS and the test facility will not have any adverse effect on SRV operability at GGNS relative to the test facility.

NRC QUESTION 2

The test configuration utilized no spring hangers as pipe supports. Plant specific configurations do use spring hangers in conjunction with snubber and rigid supports. Describe the safety/relief valve pipe supports used at your plant and compare the anticipated loads on valve internals for the plant pipe supports to the measured loads in the test program. Describe the impact of any differences in loads on valve operability.

RESPONSE TO QUESTION 2

The GGNS SRVDLs are supported by a combination of snubbers, rigid supports, anchors, and spring hangers. The locations of snubbers and rigid supports at GGNS are such that there are supports near each change of direction in the pipe routing. Additionally, only 15 of the 20 SRVDLs at GGNS have spring hangers (1 or 2), all of which are located in the drywell. The snubbers, rigid supports, and the anchor between the SRV and the "X" quencher are designed to accommodate combinations of loads resulting from piping dead weight, thermal conditions, seismic and suppression pool hydrodynamic events, and a high pressure steam discharge transient. The spring hangers are designed for the operating weight loads and to accommodate the pipe movements due to thermal, seismic and dynamic events.

The dynamic load effects on the piping and supports of the test facility due to the water discharge event (the alternate shutdown cooling mode) were found to be significantly lower than corresponding loads resulting from the high pressure steam discharge event. As stated in NEDE-24988-P, this finding is considered generic to all BWR's since the test facility was designed to be prototypical of the features pertinent to this issue.

During the water discharge transient there will be significantly lower dynamic loads acting on the snubbers and rigid supports than during the steam discharge transient. This will more than offset the small increase in the dead load on these supports due to the weight of the water during the alternate shutdown cooling mode of operation. An analysis was performed on

GGNS for the alternate shutdown cooling mode. The results of this analysis for a typical SRVDL show that the dynamic loads due to this mode are significantly lower than the steam discharge loads. Therefore, design adequacy of the SRV pipe supports is assured as these supports are designed for the larger steam discharge transient loads.

This question addresses the design adequacy of the spring hangers with respect to the weight of the water during the liquid discharge transient. Due to the nature of the design of spring hangers there will be little increased load on the spring hangers because of the water weight. The results of an analysis for a typical SRVDL show that the increased loads are mostly taken by the nearest rigid vertical supports. Therefore, it is concluded that sufficient margin exists in the GGNS SRVDL support design to adequately offset the increased dead load on the spring hangers in an unpinned condition due to a water filled condition. Furthermore, the effect of the water dead weight load does not affect the ability of SRVs to open to establish the alternate shutdown cooling path since the loads occur in the SRVDL only after valve opening.

NRC QUESTION 3

Report NEDE-24988-P did not identify any valve functional deficiencies or anomalies encountered during the test program. Describe the impact on valve safety function of any valve functional deficiencies or anomalies encountered during the program.

RESPONSE TO QUESTION 3

No functional deficiencies or anomalies of the safety/relief or relief valves were experienced during the testing at Wyle Laboratories for compliance with the alternate shutdown cooling mode requirement. All of the valves subjected to test runs, valid and invalid, opened and closed without loss of pressure integrity or damage. Anomalies encountered during the test program were all due to failures of test facility instrumentation, equipment, data acquisition equipment, or deviation from the approved test procedure.

The test specification for each valve required six runs. Under the test procedure, an anomaly caused the test run to be judged invalid. All anomalies were reported in the test report. The Wyle Laboratories test log sheet for the Dikkers 8X10 Dual Function Safety/Relief Valve tests is shown in Attachment 2. This valve is used in the Grand Gulf Nuclear Station.

Each Wyle test report for the respective valves identifies each test run performed and documents whether or not the test run is valid or invalid and states the reason for considering the run invalid. No anomaly encountered during the required test program affects any valve safety or operability function.

All valid test runs are identified in Table 2.2-1 of NEDE-24988-P. The data presented in Table 4.2-1 for each valve was obtained from the Table 2.2-1 test runs and was based upon the selection criteria of:

(a) Presenting the maximum representative loading information obtained from the steam run data,

(b) Presenting the maximum representative water loading information obtained from the 15°F subcooled water test data,

(c) Presenting the data on the only test run performed for the 50°F subcooled water test condition.

NRC QUESTION 4

The purpose of the test program was to determine valve performance under conditions anticipated to be encountered in the plants. Describe the events and anticipated conditions at your plant for which the valves are required to operate and compare these plant conditio s to the conditions in the test program. Describe the plant features assumed in the event evaluations used to scope the test program and compare them to plant features at your plant. For example, describe high level trips to prevent water from entering the steam lines under high pressure operating conditions as assumed in the test event and compare them to trips used at your plant.

RESPONSE TO QUESTION 4

The purpose of the SRV test program was to demonstrate that the SRV will open and reclose under all expected flow conditions. The expected valve operating conditions were determined through the use of analyses of accidents and anticipated operational occurrences referenced in Regulatory Guide 1.70, Revision 2. Single failures were applied to these analyses so that the dynamic forces on the safety and relief valves would be maximized. Test pressures were the highest predicted by conventional safety analysis procedures. The BWR Owners Group, in their enclosure to the September 17, 1980 letter from D. B. Waters to R. H. Vollmer, identified 13 events which may result in liquid or two-phase SRV inlet flow that would maximize the dynamic forces on the safety relief valve. These events were identified by evaluating the initial events described in Regulatory Guide 1.70, Revision 2, with and without the additional conservatism of a single active component failure or operator error postulated in the event sequence. It was concluded from this evaluation that the alternate shutdown cooling mode is the only expected event which will result in liquid at the valve inlet. Consequently, this was the event simulated in the SRV test program. This conclusion and the test results applicable to GGNS are discussed below.

The SRV inlet fluid conditions tested in the BWR Owners Group SRV test program, as documented in NEDE-24988-P, are 15° to 50°F subcooled liquid at 20 psig to 250 psig. These fluid conditions envelope the conditions expected to occur at GGNS in the alternate shutdown cooling mode of operation.

The BWR Owners Group identified 13 events by evaluating the initiating events described in Regulatory Guide 1.70, Revision 2, with the additional conservatism of a single active component failure or operator error postulated in the events sequence. These events and the plant-specific features that mitigate these events, are summarized in Table 1 of this attachment. Of these 13 events, only 10 are applicable to GGNS because of its design and specific plant configuration. Three events, namely events #3, #6 and #11 are NOT applicable to GGNS because Grand Gulf does not have a High Pressure Core Injection (HPCI) system nor a Reactor Core Isolation Cooling (RCIC) head spray.

For the 10 remaining events the GGNS specific features, such as trip logic, power supplies, instrument line configuration, alarms and operator actions have been compared to the base case analysis presented in the BWR Owners Group submittal of September 17, 1980. The comparison has demonstrated that the base case analysis is applicable to GGNS because the base case analysis includes plant features which are already present in the GGNS design. For these events, Table 1 shows what GGNS specific features are included in the base case analyses presented in the BWR Owners Group submittal of September 17, 1980. It is seen from Table 1, that most plant features assumed in the event evaluation are also existing features in GGNS. All features included in this base case analysis are similar to plant features in the GGNS design or do not have a negative effect upon this comparison. Furthermore, the time available for operator action is expected to be longer at GGNS than in the base case analysis for each case where operator action is required.

Event #7, the alternate shutdown cooling mode of operation, is the only expected event which will result in liquid or two-phase fluid at the SRV inlet. Consequently, this event was simulated in the BWR SRV test program. At GGNS this event involves flow of subcooled water (approximately 35°F subcooled) at a pressure of approximately 135 psig. The test conditions clearly envelope these plant conditions.

As discussed above, the BWR Owners Group evaluated transients including single active failures that would maximize the dynamic forces on the safety relief valves. As a result of this evaluation, the alternate shutdown cooling mode is the only expected event involving liquid or two-phase flow. Consequently this event was tested in the BWR SRV test program. The fluid conditions and flow conditions tested in the BWR Owners Group test program conservatively envelope the GGNS plant-specific fluid conditions expected for the alternate shutdown cooling mode of operation.

NRC QUESTION 5

The valves are likely to be extensively cycled in a controlled depressurization mode in a plant-specific application. Was this mode simulated in the test program? What is the effect of this valve cycling on valve performance and probability of the valve to fail open or to fail closed?

RESPONSE TO QUESTION 5

The BWR safety/relief valve operability test program was designed to simulate the alternate shutdown cooling mode, which is the only expected liquid discharge event for GGNS. The sequence of events leading to the alternate shutdown cooling mode is given below.

Following normal reactor shutdown, the reactor operator depressurizes the reactor vessel by opening the turbine bypass valves and removing heat through the main condenser. If the main condenser is unavailable, the operator could depressurize the reactor vessel by using the SRVs to discharge steam to the suppression pool. If SRV operation is required, the operator cycles the valves in order to assure that the cooldown rate is maintained within the technical specification limit of 100°F per hour. When the vessel is depressurized, the operator initiates normal shutdown cooling by use of the RHR system. If that system is unavailable because the valve on the RHR shutdown cooling suction line fails to open, the operator initiates the alternate shutdown cooling mode.

For alternate shutdown cooling, the operator opens one SRV and initiates either an RHR or core spray pump utilizing the suppression pool as the suction source. The reactor vessel is filled such that water is allowed to flow into the main steam lines and out of the SRV and back to the suppression pool. Cooling of the system is provided by use of RHR heat exchanger. As a result, an alternate cooling mode is maintained.

In order to assure continuous long term heat removal, the SRV is kept open and no cycling of the valve is performed. In order to control the reactor vessel cooldown rate, the operator is instructed to control the flow rate into the vessel. Consequently, no cycling of the SRV is required for the alternate shutdown cooling mode, and no cycling of the SRV was performed for the generic BWR SRV operability test program.

The ability of the GGNS SRV to be extensively cycled for steam discharge conditions has been confirmed during steam discharge qualification testing of the valve by the valve vendor. Based on the qualification testing of the SRV's, the cycling of the valves in a controlled depressurization mode for steam discharge conditions will not adversely affect valve performance and the probability of the valve to fail open or closed is extremely low.

NRC QUESTION 6

Describe how the values of valve C_v's in report NEDE-24988-P will be used at your plant. Show that the methodology used in the test program to determine the valve C_v is consistent with your application.

RESPONSE TO QUESTION 6

The flow coefficient, C_v, for the Dikkers safety relief valve utilized at GGNS was determined in the generic SRV test program (NEDE-24988-P). The average flow coefficient calculated from the test results for the Dikkers SRV is reported in Table 5.2-1 of NEDE-24988-P. This test value has been used by Mississippi Power and Light Company to confirm that the liquid discharge flow capacity of the Dikkers SRVs will be sufficient to remove core decay heat when injecting into the reactor pressure vessel (RPV) in the alternate shutdown cooling mode. An evaluation was performed to determine the number of SRVs required to discharge 7450 gallons per minute of water during the alternate shutdown cooling mode. This evaluation indicates that 3 SRVs are sufficient to perform this operation. Therefore, it is concluded from the C_v value determined in the SRV test that the GGNS SRVs are capable of performing the alternate shutdown cooling mode of operation.

If it were necessary for the operator to place GGNS in the alternate shutdown cooling mode, he would be assured that adequate core cooling was being provided by monitoring the following parameters: RHR or core spray flow rate, reactor vessel pressure and reactor vessel temperature.

The flow coefficient for the Dikkers SRV reported in NEDE-24988-P was determined from the SRV flow rate when the valve inlet was pressurized to approximately 250 psig. The valve flow rate was measured with the supply line flow venturi upstream of the steam chest. The C_v for the valve was calculated using the nominal measured pressure differential between the valve inlet (steam chest) and 3 feet downstream of the valve and the corresponding measured flowrate. Furthermore, the test conditions and test configuration envelope the GGNS conditions for the alternate shutdown cooling mode, e.g., pressure upstream of the valve, fluid temperature, friction losses and liquid flowrate. Therefore, the reported C_v values are appropriate for application to GGNS.

TABLE 1 - EVENTS EVALUATED

PLANT FEATURES	#1 FW Cont. Fail., FW L8 Trip Failure	#2 Press. Reg. Failure	#3 Transient HPCI, HPCI L8 Trip Failure	#4 Transient RCIC RCIC L8 Trip Failure	#5 Transient HPCS, HPCS L8 Trip Failure	#6 Transient RCIC Hd. Spr.	#7 Alt. Shutdown Cooling Shutdown Suction Unavailable	#8 MSL Brk OSC	#9 SBA, RCIC, RCIC L8 Trip Failure	#10 SBA, HPCS, HPCS L8 Trip Failure	#11 SBA, HPCI HPCI L8 Trip Failure	#12 SBA, Depress. & ECCS Over., Operator Error	#13 LBA, ECCS Overf Brk Isol
High Water Level 7 Alarm	X / S		X / NA[1]	X / S	X / S				X / S	X / S	X / NA[1]	X / S	X / S
High Drywell Pressure Alarm													
FW Level 8 Trip	X / S	X / S											
RCIC Level 8 Trip			X / NA[1]	X / S	X / S				X / S	X / S	X / NA[1]		X / S
HPCS Level 8 Trip				X / S	X / S				X / S	X / S			X / S
HPCI Level 8 Trip			X / NA[1]	X / NA[2]					X / NA[2]		X / NA[1]		X / NA[2]
HPCI/S and RCIC Initiation on Low Water Level	X / S	X / S	X / NA[1]	X / S	X / S	X / NA[3]		X / S	X / S				X / S
HPCI/S initiation on High Drywell Pressure			X / NA[1]	X / S					X / S	X / S	X / NA[1]	X / S	X / S
RCIC Initiation on High Drywell Pressure													X / NA[4]

Attachment 1 to
AECM-85/0099

TABLE 1 - EVENTS EVALUATED

PLANT FEATURES	#1 FW Cont. Fail., FW L8 Trip Failure	#2 Press. Reg. Fail.	#3 Transient HPCI, HPCI L8 Trip Failure	#4 Transient RCIC, RCIC L8 Trip Failure	#5 Transient HPCS, HPCS L8 Trip Failure	#6 Transient RCIC Hd. Spr.	#7 Alt. Shutdown Cooling, Shutdown Suction Unavailable	#8 MSL Brk OSC	#9 SBA, RCIC, RCIC L8 Trip Failure	#10 SBA, HPCS, HPCS L8 Trip Failure	#11 SBA, HPCI, HPCI L8 Trip Failure	#12 SBA, Depress. & ECCS Over., Operator Error	#13 LBA, ECCS Overf Brk Isol
Low Pressure ECCS Initiation on High Drywell Pressure												X/S	X/S
Low Pressure ECCS Initiation on Low Water Level													X/S
FW Pumps Trip on Low Suction Pressure	X/S												
HPCI Trip on High Backpressure			X/NA[1]								X/NA[1]		
RCIC Trip on High Backpressure				X/S					X/S				
Turbine Trip on Vessel High Level	X/S	X/S											
MSIVs Closure on Low Turbine Inlet Pressure	X/S	X/S						X/S					
MSIVs Closure on High Steam Flow		X/S						X/S					
MSIVs Closure on High Steam Tunnel Temperature								X/S					

TABLE 1 - EVENTS EVALUATED

PLANT FEATURES	#1 FW Cont. Fail., FW L8 Trip Failure	#2 Press. Reg. Fail.	#3 Transient HPCI, HPCI L8 Trip Failure	#4 Transient RCIC, RCIC L8 Trip Failure	#5 Transient HPCS, HPCS L8 Trip Failure	#6 Transient RCIC Hd. Spr.	#7 Alt. Shutdown Cooling, Shutdown Suction Unavailable	#8 MSL Brk OSC	#9 SBA, RCIC, RCIC L8 Trip Failure	#10 SBA, HPCS HPCS L8 Trip Failure	#11 SBA, HPCI, HPCI L8 Trip Failure	#12 SBA, Depress. & ECCS Over., Operatcr Error	#13 LBA, ECCS Overf Brk Isol
MSIV Closure on High Radiation								X/S					
Reactor Scram on Turbine Trip	X/S	X/S											
Reactor Scram on Neutron Flux Monitor		X/S											
Reactor Scram on MSIVs Closure		X/S											
Reactor Scram on High Radiation								X/S					
Reactor Scram on High Drywell Pressure									X/S	X/S	X/NA[1]	X/S	X/S
Reactor Scram on Low Water Level													X/S
Reactor Isolation on Low Water Level													X/S

KLY: X - Feature considered in Base Case Analysis
S - Feature in Plant Specific Design
NA - Not Applicable

Footnotes to Table 1

1. Not applicable because this initiating event can not occur. GGNS does not have HPCI.

2. Not applicable. A HPCI level 8 trip is not required to make the test results applicable because GGNS does not have HPCI.

3. Not applicable because GGNS does not have RCIC head sprays.

4. Not applicable because GGNS does not have RCIC Initiation on High Drywell Pressure. This does not affect the applicability of the test results to the GGNS SRVs, because lack of this feature can not cause liquid flow through the SRVs.

Attachment 2 to
AECM-85/0099

DCA NPE-5-024(1)
ATTACHMENT: 1, 6 OF 15

OPERABILITY TEST REPORT
FOR
DIKKERS ER10 SRV
FOR
LOW PRESSURE WATER TESTS
FOR
GENERAL ELECTRIC COMPANY

GENERAL ELECTRIC
NUCLEAR ENERGY BUSINESS GROUP
APPROVED DATE
VIF NO.
TRANSMITTAL NO.

PRINTS TO

175 Curtner Avenue
San Jose, California

DCA NPE-5-0290
ATT. II 7 of 15

TABLE I

OPERABILITY TEST LOG, SRV DK-1

TEST NO.	MEDIA	LOAD LINE CONFIGURATION	DATE	REMARKS
101	Steam	I	3/3/81	Test Acceptable.
102	Water	I	3/3/81	Test Acceptable.
103	Steam	I	3/3/81	Test Acceptable.
104	Water	I	3/4/81	Test Acceptable.
105	Steam	I	3/4/81	Test Acceptable.
106	Water	I	3/4/81	Test Acceptable.