ABSTRACT

Supplement No. 3 to the Safety Evaluation Report on the application filed by Gulf States Utilities Company as applicant and for itself and Cajun Electric Power Cooperative, as owners, for a license to operate River Bend Station has been prepared by the Office of Nuclear Reactor Regulation of the U.S. Nuclear Regulatory Commission. The facility is located in West Feliciana Parish, near St. Francisville, Louisiana. This supplement reports the status of certain items that had not been resolved at the time of publication of the Safety Evaluation Report, Supplement No. 1, and Supplement No. 2.

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4 REACTOR

4.6 Functional Design of Reactivity Control Systems

In FSAR Amendment 20, the applicant provided revised pages in order for the FSAR to conform to the proposed plant Technical Specifications. One of the revised FSAR pages was Figure 9.3-14 which graphically defines the upper and lower bounds of the allowable sodium pentaborate concentrations and volume. The previous revision of Figure 9.3-14 was the standard General Electric (GE) figure with the concentrations ranging from approximately 12% to 13.8% and the volume ranging from approximately 4600 gallons to 5160 gallons with a safety margin volume of approximately 250 gallons. The new figure has a concentration range of approximately 9.3% to 13.8% and the volume ranges from 3542 gallons to 5150 gallons with no safety margin. No explanation was provided for the change. On the basis of the staff's independent calculations, the lower concentration level of 9.3% is non-conservative with respect to previously approved concentration level and volume levels. The applicant subsequently provided a revised figure in a submittal dated July 8, 1985, which shows the minimum concentration as 10.5%. This concentration level was compared with other previously approved analyses and found to provide similar boration rates. Therefore, the staff concludes that the revised figure provided by the July 8th submittal is acceptable. The applicant has also committed to revise the figure in the Technical Specifications.

On the basis of the above evaluation, the staff concludes that the design of the reactivity control system meets the requirements of General Design Criterion (GDC) 26, "Reactivity Control System Redundancy and Capability," and GDC 27, "Combined Reactivity Control System Capability," and is, therefore, acceptable. The functional design of the reactivity control system meets the applicable criteria of Standard Review Plan (SRP) Section 4.6 (NUREG-0800).

5 REACTOR COOLANT SYSTEM

5.2 Integrity of Reactor Coolant Pressure Boundary

5.2.4 Reactor Coolant Pressure Boundary Inservice Inspection and Testing

This section was prepared with the technical assistance of Department of Energy (DOE) contractors from the Idaho National Engineering Laboratory.

5.2.4.3 Evaluation of Compliance With 10 CFR 50.55a(g) for River Bend Station

This evaluation supplements conclusions in Section 5.2.4.3 of the SER (NUREG-0989), which addressed the definition of examination requirements and the evaluation of compliance with 10 CFR 50.55a(g). The design of the ASME Code Class 1 and 2 components of the reactor coolant pressure boundary incorporates provisions for access for inservice examinations, as required by Paragraph IWA-1500 of Section XI of the ASME Code. 10 CFR 50.55a(g) defines the detailed requirements for the preservice inspection (PSI) and inservice inspection (ISI) programs for light-water-cooled nuclear power facility components. On the basis of the construction permit date of March 25, 1977, this section of the regulations requires that a PSI program be developed and implemented using at least the edition and addenda of Section XI of the ASME Code applied to the construction of the particular components. The components (including supports) may meet requirements set forth in subsequent editions and addenda of this Code which are incorporated by reference in 10 CFR 50.55a(b) subject to the limitations and modifications listed therein. The applicant has prepared the PSI Program based on compliance with the requirements of the 1977 Edition of the Code including addenda through Summer 1978 except for the reactor pressure vessel (RPV) or where specific written relief is requested. The staff has reviewed the results of the public meeting with the applicant on May 1, 1984, to discuss the PSI Program, the FSAR through Amendment 20 (June 1985), the applicant's May 15, 1985, response to the staff's request for additional information, the PSI Program through Revision 3 submitted on May 15, 1985, and other letters dated June 10 and June 24, 1985.

The RPV examination procedures, calibration blocks, and examinations comply with the requirements of the 1974 Edition of the Code including addenda through Summer 1975 for the vessel shell welds, and the 1977 Edition and addenda through Summer 1978 for safe-end and safe-end extension piping welds. The preservice examination of the reactor pressure vessel was performed in 1977 by a combination of manual and automated ultrasonic inspection equipment after completion of the hydrostatic test at the Chicago Bridge and Iron nuclear facilities at Memphis, Tennessee. Automated examinations were performed on shell seal welds in or below the core region and on the nozzle-to-vessel welds with pipe sizes 10 inches in diameter or larger. In addition, all areas of the N-1 through N-6 nozzle-vessel welds that were examined manually in 1977 were reexamined with automated equipment at River Bend Station. The safe-ends for the same nozzles and the safe-end extension welds were also reexamined using the automated equipment. The applicant states that all RPV examinations predate Regulatory Guide (RG) 1.150 which was issued in June 1981. The staff concludes that the preservice examinations of the RPV are acceptable because the preservice examinations

were consistent with the applicable Code and the commercial practices at the time when examinations were performed.

As a result of the staff's request for additional information dated March 20, 1985, the PSI Program was completely revised and resubmitted on May 15, 1985. Therefore, the final program review with respect to the systems and components subject to examination was evaluated based on this submittal. In addition, Appendix C of the PSI Program document contained requests for relief from ASME Code Section XI requirements that the applicant has determined impractical for the ASME Code Class 1 systems and components. These relief requests were revised in letters dated June 10 and June 24, 1985, and were supported by a technical justification. The staff evaluated the ASME Code-required examinations that the applicant determined to be impractical and, pursuant to 10 CFR 50.55a(a)(3), relief from the impractical Code requirements has been allowed wherever the applicant has demonstrated that either (1) the proposed alternatives would provide an acceptable level of quality and safety or (2) compliance with the requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. The detailed evaluation supporting this conclusion is provided in Appendix L to this report. On the basis of granting relief from these preservice examination requirements and review of the applicant's submittals, the staff concludes that the preservice inspection program for reactor coolant pressure boundary is acceptable and in compliance with 10 CFR 50.55a(g)(3).

The initial inservice inspection program has not been submitted. This program will be evaluated after the applicable ASME Code edition and addenda can be determined based on 10 CFR 50.55a(b), but before the first refueling outage when inservice inspection commences.

5.2.5 Reactor Coolant Pressure Boundary Leakage Detection

Standard Review Plan (SRP) Section 5.2.5 and RG 1.45 discuss the need to monior leakage from the reactor coolant pressure boundary to other systems. This intersystem leakage, as identified in the regulatory guide, is both (1) leakage across components, such as heat exchangers, to other water systems, such as the reactor plant component cooling water system, and (2) leakage across passive components, such as across closed isolation valves. The applicant has provided means to detect the first type of intersystem leakage, as was previously discussed in the SER. In FSAR Amendment 21, the applicant has identified a means to detect the second type of intersystem leakage, which is also referred to as the high/low pressure interface leakage, by monitoring the pressure between the two isolation valves. Detection of high pressure between the two valves is an indication of primary coolant leakage and is alarmed in the control room. Thus, the staff concludes that the method for detecting leakage across the high/low pressure interfaces meets the requirements of General Design Criterion (GDC) 2, "Design Basis for Protection Against Natural Phenomena."

On the basis of the above evaluation, the staff concludes that the reactor coolant pressure boundary leakage detection system meets the requirements of GDC 2, with regard to protection against natural phenomena, and the guidelines of RG 1.29 (Rev 3), Positions C.1 and C.2, concerning the system seismic classification, and is, therefore, acceptable. The reactor coolant pressure boundary leakage detection system meets the acceptance criteria of SRP Section 5.2.5.

? 5.2.2
See Table 1.1 in SER

SAFETY EVALUATION
TMI ACTION PLAN II.K.3.28 VERIFY QUALIFICATION
OF ACCUMULATORS ON ADS VALVES
RIVER BEND STATION UNIT 1
DOCKET NO. 50-458

1. BACKGROUND

Safety Analysis Reports (SARs) claim that air (or nitrogen) accumulators for the automatic depressurization system (ADS) valves are provided with sufficient capacity to cycle the valves open five times at design pressures. General Electric (GE) has also stated that the Emergency Core Cooling Systems (ECCS) are designed to withstand a hostile environment and still perform their function for 100 days following an accident. Licensees and applicants must demonstrate that the ADS valves, accumulators, and associated equipment and instrumentation meet the requirements specified in the plant's FSAR and are capable of performing their functions during and following exposure to hostile environments, taking no credit for non-safety-related equipment or instrumentation. Additionally, air (or nitrogen) leakage through valves must be accounted for in order to assure that enough inventory of compressed air is available to cycle the ADS valves. If this cannot be demonstrated, it must be shown that the accumulator design is still acceptable.

2. DISCUSSION

The commitment to satisfy the requirement of TMI Action Item II.K.3.28 for the River Bend Station, Unit 1 is discussed in the following submittals.

A. Gulf States Utilities Company letter from J.E. Booker to H.R. Denton, NRC, dated April 9, 1984, response to a request for additional information.

B. Gulf States Utilities Company letter from J.E. Booker to H.R. Denton, NRC, dated May 13, 1985.

3. DEMONSTRATION OF OPERABILITY

The design of the River Bend Station is such that the ADS will be available for 100 days following an accident. Each ADS valve is equipped with a 60 gallon accumulator designed for two (2) actuations at 70 percent of drywell design pressure which is equivalent to 4 to 5 actuations at atmospheric pressure. During normal plant operation, air is supplied from the non-nuclear safety (NNS) main steam system air compressors. Post-LOCA air requirements are supplied from the Penetration Valve Leakage Control System (PVLCS), a nuclear safety related Seismic Category I system.

The realignment from the main steam system air compressors to the PVLCS is performed by the plant operators from the main control room.

The PVLCS is manually actuated approximately 20 minutes after a LOCA. Prior to the manual actuation, the system is in an automatic mode and maintains the accumulators at a preset pressure. Following a loss of off-site power, the PVLCS initiation is delayed to avoid overloading due to starting currents. The ADS accumulators are designed and maintained with sufficient inventory to permit the required actuations during this period, assuming a leakage of 1 SCFH.

FSAR Section 9.3.6.3.1 indicates that the PVLCS accumulators are maintained with enough air to meet all short-term requirements of the PVLCS, the MS-PLCS, and the main steam safety/relief valve system.

Technical Specification surveillance requirements associated with the ADS accumulator system and backup system verifies that the PVLCS accumulator pressure is greater than 101 psig at least once per 24 hours.

The allowable leakage rate of 1 SCFH for the ADS air accumulator sub-system is compatible with the Emergency Core Cooling System (ECCS) performance evaluations and assumptions, and the calculations for sizing the ADS air supply system. Additionally no credit was taken for non-safety related equipment or instrumentation when establishing the allowable leakage criteria.

The air accumulator sub-system is designed to withstand Seismic Category I loads and post-accident environments.

The ADS air accumulator sub-system is defined as all the components between (and including) the check valve located on the inlet side of the accumulator and the associated main steam safety relief valve.

4. EVALUATION

4.1 The primary source of air for the ADS accumulators is from the non-nuclear safety related main steam system air compressors. Backup to this system is the nuclear safety related PVLCS. The applicant states that the PVLCS is placed in service approximately 20 minutes after it has been ascertained that a LOCA has occurred. This realignment is accomplished in the main control room. The 20-minute period is approximately equal to the time required for the PVLCS air compressors to be loaded onto the standby power supplies. The applicant has provided a statement verifying that the ADS accumulators have sufficient inventory to assure operability of the ADS valves during this 20-minute interval.

The accumulator on each ADS valve has a 60-gallon capacity which is designed for two actuations at 70 percent of drywell design pressure. This capability is equivalent to 4 to 5 actuations at atmospheric pressure.

The staff concludes that the applicant has demonstrated the long and short term capability of the automatic depressurization system and is therefore acceptable.

4.2 The applicant states that the allowable leakage rate of 1 SCFH is compatible with the ECCS performance evaluations and assumptions, and the calculations for sizing the ADS air supply. Therefore, accounting for (a) the capacity of the accumulators, (b) that the ECCS is a NSSS (GE) designed system, and (c) that previous submittals have discussed in detail the basis for the allowable leakage criteria, the staff concludes that the allowable leakage criteria of 1 SCFH address the concerns in this area and is acceptable.

4.3 The applicant has provided information acceptable to the staff indicative of the development of surveillance, maintenance, and leak testing programs for the ADS accumulator system and associated alarms and instrumentation.

4.4 The applicant has provided information confirming that:

- the backup air supply system, PVLCS, is seismically and environmentally qualified, and

- the accumulators and associated equipment are capable of performing their functions during and following an accident, while taking no credit for non-safety related equipment and instrumentation.

5. CONCLUSION

Based on the information provided by the applicant summarized in Section 3, and the evaluation performed highlighted in Section 4, the staff concludes that the Gulf States Utilities Company has verified qualification of the accumulator(s) on ADS valves for River Bend Station Unit 1, thereby satisfying the requirements of TMI Action Item II.K.3.28.

6 ENGINEERED SAFETY FEATURES

6.2 Containment Systems

6.2.1 Containment Functional Design

6.2.1.8 Pool Dynamics

6.2.1.8.3 Hydrodynamic Load Assessment

Pool Temperature Limit and SRV Inplant Tests

In accordance with criterion 5 of NUREG-0763, River Bend steel containment is required to undergo in-plant safety/relief valve (SRV) testing, since no steel containment has been subjected to such testing. The applicant requested relief from the testing requirement for the following reasons:

(1) Even though River Bend has a freestanding steel containment, the annulus, that is, the space between the shield building and the steel containment which forms the boundary of the suppression pool, has been filled with concrete. As a result, this portion of the containment which forms the boundary of the suppression pool is as rigid as the reinforced-concrete containment of Kuosheng which has undergone in-plant SRV testing. Therefore, the testing results of Kuosheng can be applied to River Bend.

(2) Perry Nuclear Power Plant also has a freestanding steel containment and the lower portion of the annulus (same as River Bend) is filled with concrete. A study was made by Cleveland Electric Illuminating Co. for Perry using a pressure time history from the Kuosheng tests as the forcing function input to the Perry structural models to obtain the response of the containment and internal structures. The resulting response spectra at selected node points are enveloped by the Perry SRV design response spectra except in the high-frequency region where similar exceedance as noted in the Kuosheng study appears. However, detailed investigation indicated that there is adequate design margin for piping and equipment at Perry. On the basis of the review of the applicant's findings, the staff concluded that Perry need not undergo any in-plant SRV tests. Since River Bend has a containment very similar to that of Perry, there is no need for River Bend to have any in-plant tests.

The staff reviewed the information provided by the applicant and found that the shear wave velocity of River Bend is much lower than that of Perry, which may have different effects on the response of the containment structure, components, and systems located therein. In response to this staff concern, the applicant reasoned that the Kuosheng observed pressure trace does not excite lower modes of vibration of the Perry analytical model, nor of the actual Kuosheng structure. The response spectra used in the River Bend design based on the General Electric (GE) SRV forcing functions provide significant responses in the lower frequencies. This indicates that the River Bend design used SRV loads which have more energy in the lower frequencies and is, therefore, more

conservative in this region than the Kuosheng traces indicated. On the basis of review and evaluation of the information provided by the applicant, the staff concludes that there is no need to perform in-plant SRV testing at River Bend.

6.6 Inservice Inspection of Class 2 and 3 Components

This section was prepared with the technical assistance of Department of Energy (DOE) contractors from the Idaho National Engineering Laboratory.

6.6.3 Evaluation of Compliance With 10 CFR 50.55a(g)

This evaluation supplements conclusions in Section 6.6.3 of the SER (NUREG-0989), which addressed the definition of examination requirements and the evaluation of compliance with 10 CFR 50.55a(g). On the basis of the construction permit date of March 25, 1977, 10 CFR 50.55a(g) requires that a PSI Program for Class 2 and 3 components be developed and implemented using at least the edition and addenda of Section XI of the ASME Code applied to the construction of the particular components. The components (including supports) may meet the requirements set forth in subsequent editions of this Code and addenda which are incorporated by reference in 10 CFR 50.55a(b) subject to the limitations and modifications listed therein. The applicant has prepared the PSI Program based on compliance with the requirements of the 1977 Edition of the Code including addenda through Summer 1978 except that the extent of examination for Class 2 welds in the residual heat removal system (RHRS) and emergency core cooling system (ECCS) are determined by the requirements of the 1974 Edition of the Code with addenda through Summer 1975, except where specific written relief is requested.

The staff has reviewed the results of the public meeting with the applicant on May 1, 1984, to discuss the PSI Program, the FSAR through Amendment 20 (June 1985), the applicant's May 15, 1985, response to the staff's request for additional information, the PSI Program through Revision 3 submitted on May 15, 1985, and other letters dated June 10 and June 24, 1985. As a result of the staff's request for additional information dated March 20, 1985, the PSI Program was revised and resubmitted in its entirety on May 15, 1985. Therefore, the final program review with respect to the systems and components subject to PSI examination was evaluated using this submittal. The most significant revisions which have been noted are:

- The exclusion of system pressure tests and visual examinations in accordance with IWC-1220 has been deleted. Although the terminology used in Paragraph IWC-1220 of Section XI, Summer 1978 Addenda is ambiguous, the intent of the ASME Code Committee as expressed in Examination Category C-H, "All Pressure Retaining Components," is clear. Paragraph IWC-1220 should not be used as a basis for excluding systems or portions of systems from the hydrostatic testing requirements of IWA-5000 and IWC-5000 of Section XI.

- The number of volumetric examinations was increased to at least 7.5% of the total number of welds in the RHRS, ECCS, and containment heat removal systems that are not exempt based on the ASME Code Section XI, 1974 Edition with addenda through the Summer of 1975.

- Appendix D contains requests for relief from ASME Code Section XI requirements that the applicant has determined not practical for Class 2 systems and components. These relief requests were revised in letters dated June 19 and June 24, 1985, and were supported by a technical justification.

The staff evaluated the ASME Code-required examinations that the applicant determined to be impractical and, pursuant to 10 CFR 50.55a(a)(3), relief from the impractical Code requirements has been allowed where the applicant has demonstrated that either (1) the proposed alternatives would provide an acceptable level of quality and safety or (2) compliance with the requirements would results in hardships or unusual difficulties without a compensating increase in the level of quality and safety. The detailed evaluation supporting this conclusion is provided in Appendix L to this report. On the basis of granting of relief from these preservice examination requirements and review of the applicant's submittals, the staff concludes that the preservice inspection program for River Bend Station is acceptable and in compliance with 10 CFR 50.55a(g)(3).

The initial inservice inspection program has not been submitted. This program will be evaluated after the applicable ASME Code edition and addenda can be determined based on 10 CFR 50.55a(b), but before the first refueling outage when inservice inspection commences.

7 INSTRUMENTATION AND CONTROLS

7.2 Reactor Protection System

7.2.2 Specific Findings

7.2.2.6 Isolation Devices

Isolation devices are used between safety-related and non-safety-related circuits to protect the safety-related circuits from damage caused by electrical faults that could occur within the non-safety-related circuits. Isolation devices are also used between redundant safety-related circuits to prevent electrical faults from adversely affecting circuits from redundant channels/divisions (i.e., the effects of the fault are contained on one side of the isolation device). The applicant has confirmed that only two types of isolation devices are used at River Bend. These are: (1) Potter Brumfield MDR relays (these are rotary-type relays providing coil-to-contact isolation), and (2) optical isolator assemblies (the assemblies consist of input and output printed circuit cards on either side of a ceramic barrier; polished quartz crystal rods embedded in the ceramic material transmit light across the barrier). The applicant confirmed that relay contact-to-contact isolation is not used at River Bend, and that FSAR Section 7.1.4.1 will be revised accordingly.

The staff audited the test plans and procedures used to demonstrate the qualification of both the MDR relays and the optical isolators as acceptable isolation devices. The acceptance criteria for both types of devices were found to be acceptable (i.e., upon application of a fault to one side of the device, no degradation occurs to circuits on the opposite side of the device). The applicant has stated that the MDR relays and optical isolation devices are seismically and environmentally qualified for their safety-related applications at River Bend. These devices are discussed in detail below.

All MDR relays used as isolation devices at River Bend are mounted within metal enclosures containing a metal barrier that separates the coil section of the relay and its associated wiring from the contact section of the relay and its associated wiring. The barrier is grounded, and is designed to prevent faults at the output (contacts) of the device from propagating to the input (coil) of the device. Since the entire relay is housed in a metal enclosure, external faults should not compromise the isolation function of the relay or influence signal integrity.

Complete functional tests were performed on the MDR relays before and after the relays underwent seismic and environmental qualification testing. The functional test program included contact resistance checks, pickup/dropout voltage testing, contact transfer/delay time tests, dielectric strength/insulation resistance tests and contact current rating tests. The MDR relays tested, successfully passed all functional tests. The dielectric strength/insulation resistance test and the contact current rating test are further discussed below.

The dielectric strength/insulation resistance test consisted of applying 1000 V ac for one minute between the normally closed contacts (wired in series) and the relay chassis (ground), first with the relay coil deenergized, and subsequently with the coil energized (120 V ac, 60 Hz). The test voltage was applied using a hipotronics testor that includes a light and alarm which are activated if leakage current exceeds 5000 microamps. After the 1000 V ac was removed, 500 V dc was applied across the same terminals and the insulation resistance to ground was measured. In each case, the insulation resistance was greater than 50,000 megohms. This test demonstrates that no arcing or damage to the relay occurs and that there is no insulation resistance breakdown (including carbon traces) upon application of the 1000 V ac.

The contact current rating tests consisted of cycling (energizing and deenergizing) the relay five times in succession for various output (contact) load configurations, including 115 V ac and 15 amps (load current through the relay contacts). The voltage drop across the contacts was measured before and after the test. The test results showed no significant increase in the voltage drop across the relay contacts (the increase was less than 2 millivolts for the 115 V ac/15-amp case). The relay single contact current rating at 115 V ac is 10 amps. This test demonstrates that a credible fault current applied to the output (contact) side of the relay will not result in relay damage, and that the fault will not propagate to the input (coil) side of the device. The staff considers 115 V ac/15 amps to be the minimum credible fault voltage/current acceptable for qualification of components as acceptable isolation devices.

On the basis of the results of the above tests and the relay mounting configuration (metal enclosure with barrier between the coil and contact portions of the device), the staff concludes that the Potter Brumfield MDR rotary type relays (model MDR-4130-1) as installed at River Bend are acceptable isolation devices for use between redundant safety-related circuits, and between safety-related and non-safety-related circuits.

The optical isolator assemblies contain either 4 or 8 input and output card pairs, with approximately 4 to 12 individual isolators per card pair, depending upon the specific application. Quartz rods (light pipes) transmit signal information across the ceramic isolation barrier provided between the input cards and the output cards. All cards on a given side of the isolation barrier are powered from the same electrical division. Maximum credible voltage/current tests and 5000-V ac card isolation tests were performed on the optical isolator assemblies. These tests are discussed below.

The maximum credible voltage/current test was performed for the following input/output card pairs:

- Field Contact Input/High-Level Output
- Field Contact Input/5-V Logic Output
- Field Contact Input/12-V Logic Output
- Field Contact Input/Floating Low Level Output
- High Speed Input/High Speed Output
- Analog Input/Analog Output
- Logic Input/12-V Logic Output

The maximum credible fault voltage and current values were determined by identifying the largest voltages present within plant instrumentation cabinets/panels/control boards and the largest associated branch fuses/circuit breakers. These values for River Bend are 125-V ac/30 amps and 140-V dc/30 amps. The fault voltages were applied to each input/output card pair in each of the following test circuit configurations:

(1) fault voltage applied between each input terminal (wired in parallel) and ground (signal returns and the isolator assembly housing)

(2) fault voltage applied in the transverse mode between the input terminals (wired in parallel) and the returns (wired in parallel)

(3) fault voltage applied between each output terminal (wired in parallel) and ground

(4) fault voltage applied in the transverse mode between the output terminals (wired in parallel) and the returns (wired in parallel)

The fault voltages were applied for a one-minute duration for each test configuration. For each test case, the opposite side of the isolation barrier was monitored (using a memory oscilloscope) to detect any perturbations that might occur. The acceptance criteria for all tests was that no fault source voltage appear on the opposite side of the isolation barrier. The fault voltages were applied via fused (30-amp) connections; no fuses failed during the tests. The test results showed there were two cases in which a voltage perturbation occurred on the opposite side of the isolation barrier, because of arcing from the input cards to the assembly chassis (common to both sides of the isolation barrier), causing a momentary increase in ground potential. The two cases were the high-speed card pair and the analog card pair. The amplitude of the perturbations was less than 2 V and the duration was less than 100 milliseconds. Both cases involved test configuration 1 (above) and the application of 140 V dc. The staff does not consider these perturbations significant with respect to impairing the capability of the optical isolator assembly to perform its isolation function. Following the tests, standard production/operability tests (preprogrammed automated tests) were performed on the isolator cards that were located on the opposite side of the isolation barrier from where the faults were applied. All cards were tested successfully (i.e., remained operable following the fault tests). Isolator cards to which the faults were applied were destroyed during the fault tests.

The 5000-V ac card isolation test consisted of applying 5000 V ac between all input terminals (wired in parallel) and the isolator assembly chassis (ground) for the same input/output card pairs listed above for the credible fault tests. Subsequently, a standard production/operability test was performed on the output cards to verify that the isolation provided between the input and output sides of the assembly is sufficient to prevent the 5000 V ac applied to the input side of the device from impairing the function of the output cards. The above test was repeated with the 5000 V ac applied to the output cards and a production/operability test performed on the input cards. For all cases, the acceptance criterion (i.e., no damage occurring to any devices on the opposite side of the isolation barrier) was satisfied.

On the basis of its review, the staff concludes that the MDR relays and optical isolator assemblies (models 133D9947 and 147D8804) used to provide physical and electrical isolation between redundant safety-related circuits, and between safety-related and non-safety-related circuits, satisfies the applicable acceptance criteria (i.e., an abnormal/fault voltage/current on one side of the isolation device does not affect the functional capability of circuitry on the opposite side of the device), and therefore, are acceptable. This resolves Confirmatory Item 26 as listed in Table 1.4 of the River Bend SER. It should be noted that this evaluation does not include those isolation devices used in the emergency response and information system (ERIS) or the digital radiation monitoring system (DRMS). These devices are discussed in Sections 7.7.2.3 and 7.6.2.7 of the SER.

7.3 Engineered Safety Features Systems

7.3.2 Specific Findings

7.3.2.7 Initiation of ESF Supporting Systems

The River Bend design includes safety-related air conditioning units and unit coolers (listed ~~below~~ in Table 7.1) which provide ventilation and cooling for rooms/areas containing safety-related equipment.

Table 7.1 Safety-related air conditioning units, units coolers, and area serviced

Cooler	Area serviced	Cooler	Area serviced
1HVC*ACU1A+	Control room	1HVR*UC5	HPCS pump room
1HVC*ACU1B+	Control room	IHVR*UC6	RCIC & RHR Division 1 equipment room
1HVC*ACU2A+	Switchgear/battery/ cable areas	1HVR*UC7	MCC areas
1HVC*ACU2B+	Swichgear/battery/ cable areas	1HVR*UC8	Main steam pipe tunnel, north
1HVC*ACU3A+	Chiller equipment room	1HVR*UC9	RHR Division 2 equipment area
1HVC*ACU3B+	Chiller equipment room		
1HVR*UC1A++	Containment	1HVR*UC10	MCC areas
1HVR*UC1B++	Containment	1HVR*UC11A	East SGTS area/west equipment area
1HVR*UC2	RWCU pump room		
1HVR*UC3	RPCCW and CRD areas	1HVR*UC11B	East SGTS area/west equipment area
1HVR*UC4	Auxiliary building general area		

+These air conditioning units start automatically following a LOCA signal [i.e., reactor vessel low water level (level 1) and/or high drywell pressure] and load sequence permissive if power is available to the respective emergency buses and an associated chilled water pump is running.

++These unit coolers start automatically on a LOCA signal if power is available at the respective emergency buses.

To end of section

TC

Unit coolers 1HVR*UC2 through 1HVR*UC10 and 1HVR*UC11A&B do not receive automatic start signals. These unit coolers must be manually started from the control room. Because some of the unit coolers provide cooling for rooms containing engineered safety features (ESF) equipment, the staff raised concerns that the unit coolers did not automatically start in response to system level initiation signals (manual or automatic) for the respective ESF systems. The Technical Specification definition of OPERABILITY states that in order for a system, subsystem, train, component, or device to be considered operable, it must be capable of performing its function, and that all necessary attendant auxiliary/supporting items of equipment necessary for the system, subsystem, train, component, or device to perform its function (e.g., electrical power, cooling or seal water, lubrication, etc.) must also be capable of performing their related support function or functions. It is the staff's understanding that room cooling is required for ESF equipment to operate properly. The staff was also concerned that ESF pump room high temperature conditions were not adequately annunciated in the control room.

The applicant has stated that unit coolers 1HVR*UC2 through 1HVR*UC10 and 1HVR*UC11A&B will be run continuously, and therefore, automatic initiation of the unit coolers is not required. Control room annunciation is provided for certain conditions resulting in unit cooler failure. Examples are cooling water supply valves closed and loss of power. However, the staff was concerned that a unit cooler failure could go undetected. All conditions that could result in unit cooler failure are not/cannot be annunciated. To resolve this concern, the applicant has included surveillance of unit coolers 1HVR*UC2 through 1HVR*UC10 and 1HVR*UC11A&B as part of the control building and auxiliary building daily logs, with the exception of 1HVR*UC8. This surveillance consists of plant personnel physically going to the individual unit cooler locations and verifying air flow through the coolers. The staff concludes that the daily surveillance is sufficient to ensure that a unit cooler failure does not go undetected.

Unit cooler 1HVR*UC8 provides cooling to the north main steam pipe tunnel. This is a high radiation area which cannot be accessed for surveillance during operation. The applicant has indicated that the area served by 1HVR*UC8 is a small area containing several motor-operated valves and containment isolation valves. The unit cooler is provided to keep the temperature in this area below the temperature limit of 122°F. The temperature has been analyzed to go as high as 244°F on unit cooler failure. River Bend Technical Specification 3/4.7.8 (Area Temperature Monitoring) requires that if the temperature exceeds the temperature limit by more than 30F°, the temperature be restored to within the limit within 4 hours, or that all equipment in the affected area be declared inoperable. Redundant high area temperature alarms are provided in the control room from the safety-related leakage detection system (LDS) if the temperature in the north main steam pipe tunnel reaches 135°F. The staff concludes that adequate provisions have been taken to ensure that the temperature in the north main steam pipe tunnel area served by 1HVR*UC8 remains within acceptable limits.

On the basis of the above, the staff concludes that automatic initiation of unit coolers 1HVR*UC2 through 1HVR*UC10 and 1HVR*UC11A&B is not required, and that the combination of periodic surveillance and area temperature alarms is sufficient to ensure unit coolers operability, and therefore, the operability of the associated ESF equipment. This resolves Confirmatory Item 30 as listed in

Table 1.4 of the River Bend SER. It is noted that air conditioning units 1HVC*ACU1A&B, 1HVC*ACU2A&B, and 1HVC*ACU3A&B are also verified to be operable daily in accordance with surveillance required by the control building's daily log. The areas served by these unit coolers are commonly accessed during plant operation. In addition, alarms are received in the control room on inlet filter high differential pressure and high discharge temperature for 1HVC*ACU1A&B and 1HVC*ACU2A&B. River Bend Technical Specification 3/4.7.8 also contains temperature limits for those areas served by all unit coolers listed above, with the exception of the containment unit coolers 1HVR*UC1A&B. The containment unit coolers are provided with discharge temperature indication and low flow alarms in the main control room.

7.6 Interlock Systems Important to Safety

7.6.2 Specific Findings

Insert 7.6.2.2 High-Pressure/Low-Pressure System Interlocks

7.6.2.5 Isolation Between the Neutron Monitoring System and Rod Control and Information System

The rod pattern control system (RPCS) is a subsystem of the rod action control system (RACS) portion of the rod control and information system (RCIS). The RPCS is a redundant system (Divisions 1 and 2) designed to limit the consequences of a rod drop accident by restricting control rod movement (i.e., initiating rod blocks) to within preestablished patterns. The RPCS is powered from the 120-V ac emergency safeguards buses. RPCS Division 1 circuitry is located in RACS cabinet 1H13*P651 in the control room. This cabinet also receives inputs from Divisions 1 and 4 of the neutron monitoring system (NMS), and inputs from non-safety-related sources (e.g., the operators' rod control module and the refuel platform). RPCS Division 2 circuitry is located in RACS cabinet 1H13*P652, which receives inputs from NMS Divisions 2 and 3 and from non-safety-related sources. NMS Divisions 1 and 3 are powered from reactor protection system (RPS) bus A, and NMS Divisions 2 and 4 are powered from RPS bus B. The staff's initial review raised concerns that the isolation provided between the NMS and the RCIS, and between non-safety-related circuits and safety-related circuits within the RACS cabinets may not be sufficient to prevent electrical faults from affecting redundant divisional circuits.

The staff has subsequently reviewed all inputs to the RACS cabinets, both safety related and not safety related. All inputs to the RACS cabinets are buffered using optical isolation devices. These devices are the light-emitting diode/photo transistor type mounted on printed circuit (PC) cards. Where RACS inputs are from the same division (e.g., NMS, mode switch, turbine first-stage pressure, rod position multiplexers, scram discharge instrument volume level), only the buffering is provided. Where the inputs are from a redundant division (NMS) or from a non-safety-related source, electrical isolation using qualified quartz rod isolator modules (discussed in Section 7.2.2.6 of this supplement) is provided in addition to the buffering. In addition, RACS inputs from the RCIS itself (e.g., from the rod gang drive system cabinet and the operator's control module) are isolated using the quartz rod modules.

The use of qualified isolation devices at the RACS cabinet boundary prevents electrical faults in non-safety-related circuits external to the cabinets from affecting internal safety-related circuits. The staff has concluded that the isolation provided between the NMS and the RCIS is sufficient because (1) in

Where does this go? 7.7.6.2.2 High-Pressure/Low-Pressure System Interlocks

SSER 3

~~7. . . . Surveillance of Interlock Switches~~

In the SER and SSER #1 at Section 7.6.2.3 ~~we~~ the staff stated that ~~we~~ it would include in the Technical Specifications a requirement for surveillance testing of certain interlock switches. The applicant, by letter dated ~~July~~ ~~August 4~~, August 1, 1985, furnished a commitment to include in its procedures for surveillance testing a requirement to perform the surveillance testing on these interlock switches. ~~We~~ The staff ~~have~~ has reviewed the applicant's commitment, cited above, and finds it acceptable. This matter is, therefore, resolved.

addition to the buffering, coil-to-contact isolation is provided, (2) all other inputs to the RACS cabinets are buffered/isolated as discussed above, and (3) should a fault within the RCIS degrade the NMS, redundant and diverse instrumentation is available to accomplish all required protective functions (reactor scram and rod block). This resolves Confirmatory Item 38 as listed in Table 1.4 of the River Bend SER.

7.7 Control Systems

7.7.2 Specific Findings

7.7.2.1 High-Energy Line Breaks and Consequential Control Systems Failures

The applicant was asked to determine whether multiple non-safety-related (control) systems failures, resulting from the adverse environment created by a high-energy line break (HELB), could result in consequences more severe than previously considered in the FSAR Chapter 15 accident analyses. This concern is addressed in IE Information Notice 79-22. The applicant has performed an analysis of the River Bend Station control systems and high-energy piping, and concluded that for all postulated HELBs, the consequences of the break coupled with the effects of all postulated non-safety-related equipment failures, are bounded by (i.e., are less severe than) the consequences of the events analyzed in Chapter 15 of the River Bend FSAR. Details of the applicant's analysis and the staff's evaluation of the analysis are provided below.

The applicant identified all non-safety-related/control systems that could affect reactor critical parameters (e.g., water level, pressure, critical power ratio). Systems with no controlling functions and systems that do not interface with reactor operation or reactor parameters were eliminated from the analysis. Examples of these systems are lighting, communications, annunciators, the computer, refueling equipment, ventilation systems, mechanical and structural systems (e.g., structural steel, tanks, cranes), and electrical systems which will not impact critical reactor parameters on loss of power. For those systems that can affect reactor critical parameters, the applicant compiled a list of system components to be included in the HELB analysis. Mechanical components (e.g., tanks and pipes) and instruments providing dedicated inputs to the computer, indicators, alarms, or position status information were excluded from the list. Instrument-sensing lines, and position switches that are interlocked with other equipment were included in the analysis. Motor control centers (MCCs) were considered for analysis; however, since none of the remaining components were mounted at MCCs or powered directly from an MCC, MCCs were eliminated from the analysis. In general, the final list of non-safety-related/control system components that could affect critical reactor parameters consisted of valves, switches, transmitters, and controllers.

The applicant then identified all high-energy lines at River Bend using the criteria for high-energy lines established in FSAR Section 3.6. High-energy lines are defined as those which are in operation or are maintained pressurized during normal plant conditions where the maximum temperature of the fluid in the line exceeds 200°F or the maximum pressure of the line exceeds 275 psig. High-energy lines that operate above these limits for less than 2% of the time are classified as moderate-energy lines and were excluded from the analysis. High-energy lines that are less than 1 inch in diameter were also excluded. The exclusion of these lines is acceptable because (1) breaks of moderate-energy fluid system

piping are not postulated to occur in accordance with Branch Technical Position (BTP) MEB 3-1 (see SRP Section 3.6.2), and (2) the environmental effects of breaks of lines 1 inch in diameter or smaller are less severe than for larger lines considered in the analysis (typically, these are instrument-sensing lines whose failure can be detected from the abnormal behavior of instruments associated with the broken line). Instrument line failures resulting from breaks in larger high-energy lines were considered in the analysis.

The applicant performed a plant walkthrough using maps of the reactor, turbine, and auxiliary buildings in order to subdivide the plant into HELB zones. Each zone is a separate area of the plant which is bounded by walls, ceiling, floors, etc., so that the environmental effects of a HELB in a given zone are confined to that zone, or in some cases, are also confined to adjacent zones. Certain zones extend between elevations because of open floor gratings or hoist openings between elevations.

Next, the applicant determined those zones in which components that can affect critical reactor parameters are located. The high-energy lines identified were then assumed to break at all locations (zones) where the non-safety-related/control components are located. The applicant used a "sacrificial approach" when analyzing the effects of a pipe break in a given zone (i.e., all non-safety-related/control components in that zone were assumed to fail). All component failure modes were considered to determine the worst-case failures for all components. Where a HELB could affect non-safety-related/control components in more than one zone (e.g., a break within a small cubicle can conceivably blow out the door and the environmental effects of the break could affect components in the adjoining larger volume zone), all components in all affected zones were considered to fail in their worst states. The sacrificial approach covers all potential component failure mechanisms (i.e., pipewhip, jet impingement, humidity, temperature, pressure, and radiation) since this approach assumes that the break will adversely impact all components in the respective zone(s).

The applicant has analyzed the worst-case combined effects of each HELB and all consequential non-safety-related/control systems failures. Where the worst-case failure mode for a component was not readily discernible, all failure modes and their consequences were analyzed. The consequences of these events were then compared with the accident and transient analyses presented in Chapter 15 of the River Bend FSAR. The worst-case event was determined to be a break in a high-energy line of a moisture separator vent and drain in the turbine building which results in a partial loss of feedwater heating. The failure of non-safety-related/control components in this zone can result in a further loss of feedwater heating and a resultant increase in reactor power, and may cause a turbine trip. The applicant determined that if the turbine trip occurs at a reactor power level elevated from the initial operating value, the reactor may experience a change in critical power ratio greater than that considered in the FSAR Chapter 15 analyses. However, subsequent analysis performed by the applicant has demonstrated that the effects of this accident event, including consideration of a single active failure in a mitigating safety system, are bounded by the Chapter 15 analyses. The applicant has determined that the combined consequences of all other HELBs and consequential non-safety-related/control system component failures are also bounded by the River Bend accident and transient analyses presented in Chapter 15 of the FSAR.

On the basis of a detailed review of the applicant's analysis of HELBs and consequential non-safety-related/control system component failures for several different zones (including the worst-case-event zone), the staff has concluded that the methodology used and the results of the analysis performed by the applicant are acceptable. This resolves Confirmatory Item 41 as listed in Table 1.4 of the River Bend SER.

8 ELECTRIC POWER SYSTEMS

8.3 Onsite Emergency Power Systems

8.3.1 AC Power Systems

In Section 8.3.1 of the River Bend SER, the staff stated it would confirm the correction of a typographical error on FSAR Table 8.3-2 regarding deenergization of the low-pressure core spray (LPCS) or residual heat removal (RHR) pump in 2 hours and confirm that procedures exist to control this. The staff also stated that it would evaluate a synopsis of the Division I and II diesel generator qualification test results when they are available. The Division I and II diesel generators are manufactured by Transamerica Delaval, Inc. (TDI). The staff has reviewed the qualification of similar diesels at Shoreham Nuclear Power Station with respect to IEEE Std. 387 and RG 1.9 and has found them acceptable. The TDI diesel generators, however, are also the subject of a detailed generic review which was initiated as the result of failures experienced on the Shoreham units. The results of the generic review will, therefore, govern for qualification of the River Bend units. These results for River Bend are reported below in the section titled, "Qualifications of TDI Emergency Standby Diesel Generators."

FSAR Amendment 20 states that the Division I and II diesel generators were each given a load capability test at their rated load of 3500 kW for 24 hours and that this satisfies the 110% overload requirement of RG 1.108, Position C.2.a(3) because it is more than 110% of the machines' qualified load. The staff does not agree that testing the machine to 110% of the maximum qualified load that it will carry meets the RG 1.108 requirement. The requirement is to test the machine to 110% of its continuous rating. The staff, however, is making an exception to this requirement for the Division I and II diesel generators at River Bend because of the concern identified in the TDI diesel generic evaluation. The staff has determined that the diesel generators are capable of delivering 3130 kW continuously and load testing should be limited to this

value. Although these tests do not strictly adhere to the guidelines of RG 1.108, they do adequately demonstrate the diesel generator capability to assume the actual load requirements for accidents and transients as described below. The remaining test requirements in RG 1.108 will be conducted on the Division I and II diesel generators as prescribed in the regulatory guide. Because the Division III diesel generator is not a TDI unit, it will be tested in accordance with all the requirements of RG 1.108.

With regard to the deenergization of the LPCS or RHR A pump, the applicant has since revised the entire loading profile on the diesel generator units which the staff had originally reviewed. The most recent diesel generator loading for Divisions I and II was submitted by the applicant in FSAR Amendment 21. The applicant has reduced the loading on Divisions I and II from an original maximum of 3724 kW down to the current maximum of 2886 kW to demonstrate adequate load margin on its TDI diesel generators. The applicant has accomplished this through a combination of transferring loads (Standby Service Water Pump 2C to Division III), delaying the start of loads, manually deenergizing loads, eliminating loads, and assuming reduced power input to loads. This resolves Confirmatory Item 44.

The kilowatt demand of each load on the diesel generators was calculated by using brake horsepower and the efficiency data supplied by vendors of the respective equipment. Operator action is assumed at 2 hours into the LOCA load profile to shed automatically sequenced loads and load other required manually actuated loads. Motor-operated valves are assumed to have completed their stroke by 10 minutes into the load sequence. The staff has reviewed the proposed loading profile of the Division I and II diesel generators and finds it acceptable. Therefore, Outstanding Issue 10a is closed. The load-carrying capability of the Division I and II diesel generators is addressed as part of the TDI generic review. The evaluation of these units is covered below in the section titled, "Qualification of TDI Emergency Standby Diesel Generators."

As stated above, the Standby Service Water Pump 2C will be moved to the Division III (HPCS) diesel generator. Associated with this change, a standby service water pump room vent fan and standby service water pump discharge valve will also be energized from Division III. All the Division III loads will be simultaneously loaded onto the diesel generator with the exception of the standby service water pump motor which will be sequenced to operate at 30 seconds after the diesel generator circuit breaker closes. The maximum load on the diesel generator will be 2393 kW, which is less than the diesel generator continuous rating of 2600 kW. The staff has reviewed the revised loading of the Division III diesel generator and finds it acceptable.

In Section 8.3.1 of the SER, it was stated that all Class 1E motors at River Bend are capable of starting and accelerating their driven equipment with 70% of motor nameplate voltage applied to motor terminals without affecting performance or equipment life. FSAR Amendment 19 has changed the 70% figure to 80%. The staff was concerned that if the 80% figure applied to all Class 1E motors, the motors would not be capable of starting during degraded voltage conditions. This is based on the applicant's March 5, 1984, letter which provided a voltage profile that showed less than 80% starting voltage available to start major Class 1E motors under degraded voltage conditions. In FSAR Amendment 21, the applicant clarified that only the motors driving air compressors 1LSV*C3A and 1LSV*C3B require 80% voltage to start, and calculations have determined that the minimum starting voltage available at the motor terminals is 89.63%. The remaining Class 1E motors still require only 70% voltage to start. This resolves the staff's concern on this issue and is acceptable. Therefore, Outstanding Issue 22 is closed.

Insert Pack X

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SUPPLEMENTAL SAFETY EVALUATION REPORT

RIVERBEND STATION UNIT 1

DOCKET NO. 50-348

~~8.3.1.1~~ Qualifications of TDI Emergency Standby Diesel Generators

~~1. Introduction~~ ~~(the applicant)~~

~~Gulf States Utilities Company (GSU) is seeking a full-power operating license for the River Bend Station Unit 1. One matter which has been of concern to the NRC staff has~~ The staff has been concerned about the reliability of standby emergency diesel generators (EDGs) manufactured by Transamerica Delaval, Inc. (TDI). These generators are used at River Bend and other sites.

EDG TDI

Concerns regarding the reliability of large-bore, medium-speed diesel generators manufactured by TDI for application at domestic nuclear plants were first prompted by a crankshaft failure at the Shoreham Nuclear Power Station in August 1983. However, a broad pattern of deficiencies in critical engine components subsequently became evident at the Shoreham Nuclear Power Station and at other nuclear and non-nuclear facilities employing TDI diesel generators. These deficiencies stem from inadequacies in design, manufacture, quality assurance/quality control (QA/QC) and ~~QA/QC~~ by TDI.

QA/QC

River Bend ~~Station Unit 1~~ is served by two TDI model DSR-48 diesel engines, designated ~~emergency diesel generators~~ (EDGs) 1A and 1B. These EDGs are inline eight-cylinder, four-cycle, turbocharged, aftercooled engines. Each has a nameplate continuous-load rating of 3500 kW with an overload rating of 3900 kW, and operates at 450 rpm with a brake mean effective pressure (BMEP) of 225 psig.

BMEP

Check on Shoreham supplement

Rayburn 101 Refs Letters

¶ The applicant ~~GSU~~ has been actively involved in the TDI Diesel Generator Owners Group, an organization formed by the applicant ~~GSU~~ and 12 ~~twelve~~ other utilities to resolve reliability issues stemming from the early problems with TDI engines. With the assistance of the Owners Group, the applicant ~~GSU~~ has largely completed a comprehensive program to verify and enhance the reliability of the River Bend diesel generators for standby nuclear service. The staff's evaluation of this program is provided ~~herein.~~ below.

(1) ~~2.0 Background and Discussion~~

(1.1) 2.1 TDI Owners Group

On March 2, 1984, the TDI Diesel Generator Owners Group submitted a plan to the NRC which, through a combination of design reviews, quality revalidations, engine tests, and component inspections, is intended to provide an in-depth assessment of the adequacy of the respective utilities' TDI engines to perform their safety-related function.

The Owners Group Program involves the following two major elements:

(a) ~~(1)~~ Phase I: Resolution of 16 known generic problem areas intended by the Owners Group to serve as a basis for the licensing of plants during the period prior to completion and implementation of the Owners Group Program.

(b) ~~(2)~~ Phase II: A design review/quality revalidation (DR/QR) of a large set of important engine components to ~~as~~ensure that their design and manufacture, including specifications, quality control, and quality assurance and operational surveillance and maintenance, are adequate.

The Owners Group Program includes provisions for special or expanded engine tests/inspections, as appropriate, to verify the adequacy of the engines and components to perform their intended functions.

The 16 known problem areas (Phase I issues) identified by the Owners Group include the engine base and bearing caps, cylinder block, crankshaft, connecting rods, connecting rod bearing shells, piston skirts, cylinder head studs, push rods, rocker arm capscrews, turbocharger, jacket water pump, high-pressure fuel oil tubing, air-start valve capscrews, and engine-mounted electrical cable.

The Owners Group has issued reports detailing its proposed technical resolution of each of the 16 Phase I issues. These generic reports analyze the operational history, including failure history, of each of these components. In addition, these reports evaluate the causes of earlier failures and problems, the adequacy of the components to meet functional requirements, and provide recommendations concerning needed component upgrades, inspections, and testing.

The Owners Group has also issued the DR/QR (Phase II) report, Revision 1, dated March 7, 1985, for the River Bend EDGs. This report documents the results of the design review and quality revalidation which was performed on all components critical to the operability and reliability of the engines, including the 16 components identified by the Owners Group as known problem areas. The Owners Group performed the design reviews and identified the component quality attributes to be verified. The actual component inspections to verify the quality attributes were generally performed by GSU. Engineering dispositions made by GSU on the basis of the inspection results were reviewed by the Owners Group.

(1.2) ~~2.2~~ Engine Inspections and Tests

The engine disassembly and inspection performed in support of the DR/QR effort took place in 1984, before ~~prior to~~ preoperational testing. The inspections included all Phase I components plus inspection of the engine gears and wrist pin bushings. Other components were included in the inspection, based on operating experience at other plants and recommendations of the Owners Group as needed to support Phase II. A summary of the inspections performed and the results was enclosed with a letter dated May 17, 1985, and was recently updated by letter dated June 21, 1985.

? from Dapple

After the ~~Following~~ engine was reassembled, crankshaft deflection measurements, torsiograph testing, and engine break-in tests were conducted in accordance with NRC staff criteria as identified in Section 4.6, "Interim Basis for Licensing," of the staff's generic evaluation of the Owners Group Program

R

Plan which was enclosed ~~by~~ in a letter dated August 13, 1984, to J. George, Owners Group, from D. Eisenhut, NRC,

A description of the preoperational test program of the ~~RBS~~ River Bend engines was submitted with the ~~GSU~~ applicant's letter dated May 17, 1985. Except as noted below, ~~GSU~~ the applicant states that the test program was performed in compliance with ~~Regulatory~~ Guide 1.108. The preoperational test program did not include a 2-hour overload test pursuant to ~~Section~~ Position C.2.a(3) of RG 1.108. ~~GSU~~ The applicant justified the exception to the criterion (see letter dated May 15, 1985), ? Rev on grounds that a 24-hour test at the manufacturer's continuous rating of 3500 ~~KW~~ exceeds by 10% the maximum load (3130 ~~KW~~ as given in FSAR Figures 8.3-2a and 2b ~~in FSAR~~) at which the engines would actually be run during emergency service. ~~GSU~~ The applicant maintained, therefore, that the 24-hour test at 3500 ~~KW~~ met the intent of the ~~R~~egulatory ~~G~~uide.

At the conclusion of the preoperational test program, an engine inspection not involving major engine disassembly was conducted. This inspection included visual inspection of critical components by removal of access covers and analysis of the engine oil. The inspections and results were documented by letter dated June 21, 1985.

(1.3)

2.3 Component Replacement and Modifications

Some of the more significant component replacements or modifications implemented to date involve Phase I components and include the following:

small solid fillets

- The cylinder liners, cylinder heads, cylinder head studs, and block liner landing have been modified to reduce mechanical interference stresses in order to increase the margin against cylinder block cracking.

- Original piston skirts were replaced with improved "AE" piston skirts

- Valve pushrods were replaced with improved friction welded design.

- Turbocharger mounting bracket was stiffened to reduce vibration.

- Cylinder heads have been replaced with newly manufactured "Group III heads" to reduce potential for water leakage into cylinders.

- The jacket water pumps were replaced with pumps with a nodular iron impeller without a keyway.

- Fuel injection tubing not meeting acceptance criteria developed by the Owners Group ~~were~~ was replaced.

(1.4)

2.4 Qualified Load

The adequacy of the ~~RBS~~ River Bend crankshaft was a major focus of attention between ~~GSU~~ the applicant and the NRC staff. The ~~RBS~~ River Bend crankshafts are similar in design to the replacement crankshafts at Shoreham, which were approved by the staff for a qualified load of 3300 ~~KW~~ on the basis of 10^7 cycle test at loads equal to or exceeding 3300 ~~KW~~. ~~Due to~~ Because of differences in the generators and flywheels between ~~RBS~~ River Bend and Shoreham, operation of the ~~RBS~~ River Bend engines at 3130 ~~KW~~ produces nominal torsional stresses in the crankshafts which are comparable to those at Shoreham at ~~3300 KW~~. However, the factor of safety for the ~~RBS~~ River Bend crankshaft at 3130 ~~KW~~ could be up to 14% lower than exists at Shoreham at 3300 ~~KW~~ ~~due to~~ because of a higher tensile strength ~~which~~ that exists in the Shoreham crankshafts and the fact that they have been shot peened.

~~GSU~~ The applicant has submitted a number of analyses and data to support 3130 ~~KW~~ as an acceptable qualified load level in lieu of performing a confirmatory 10^7 cycle test at that load level on ~~an RBS~~ a River Bend engine. Although 3130 ~~KW~~ is less than the manufacturer's continuous nameplate rating of 3500 ~~KW~~, it exceeds the maximum emergency service load which would be placed on these engines during an actual design-basis accident (see FSAR Table 8.3-2 ~~of FSAR~~). ~~GSU~~ The applicant stated in its letter dated May 17, 1985, that appropriate operating procedures have been prepared to ensure that the ~~RBS~~ River Bend engines are not loaded above the "qualified" load.

Failure Analysis Associates, Inc. (FaAA), a consultant to the Owners Group, has estimated a factor of safety of 1.39 for the crankshaft at 3130 ~~KW~~ and a nominal speed of 450 ~~RPM~~. (see applicant's ~~GSU~~ letter dated May 16, 1985). The applicant ~~GSU~~ also submitted a report from its consultant, FEV (Research Society for Energy, Technology and Internal Combustion Engines) by letter dated June 12, 1985. FEV calculated a safety factor of 1.205 for the crankshafts at 3130 ~~KW~~ and 450 ~~RPM~~ which, according to FEV, is within the range normally considered adequate by German engine manufacturers. Differences between the FaAA and FEV estimates were attributed by FEV to the use of different S-N (stress vs. cycles) curves. FEV used a S-N curve based on bench tests of actual crankshafts, whereas FaAA, according to FEV, employed a S-N curve based on laboratory data.

In response to concerns by the NRC staff concerning the proximity of the nominal speed of 450 ~~RPM~~ to the 5th-order harmonic resonant speed of 455 ~~RPM~~, the applicant ~~GSU~~ provided additional information from FaAA by letter dated June 12, 1985, indicating the response to the 5th-order harmonic is small and is excited only by variations in the combustion pressure from cylinder to cylinder. To prevent sustained operation under conditions of engine imbalance and overspeed, the applicant ~~GSU~~ will adopt the following (see applicant's ~~GSU~~ letter dated June 12, 1985):

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- A caution statement will be added to the engine operation and surveillance procedures to avoid operation between 453 and 457 ~~RPM~~.

- During engine operation, exhaust gas temperatures will be monitored to verify that they remain within ± 50~~°F~~ of the average for all cylinders.

- Generator ~~frequency~~ will be monitored and maintained within 60 Hz ± 0.2 Hz. ?

between 58.8 Hz and 60.2 Hz.

(2)

~~3.0~~ Evaluation

Appendix M supplement

Appendix M

~~Enclosure 1~~ to this ~~SER~~ is a Technical Evaluation Report (TER) entitled "Review and Evaluation of Transamerica Delaval, Inc., Diesel Engine Reliability and Operability~~--~~ River Bend Station Unit 1." This TER was prepared by Pacific Northwest Laboratory (PNL) which is under contract to the NRC to perform technical evaluations of the TDI Owners Group generic program, in addition to plant-specific evaluations relating to the reliability of TDI diesel~~s~~ engines. PNL has retained the services of several expert diesel consultants as part of its review staff.

TDI OG

The staff concurs with the findings of the PNL TER, and incorporates the TER as part of this SER supplement ~~Safety Evaluation Report~~ by reference.

?

This ~~SER~~ supplement and the ~~enclosed~~ appended TER precede completion of the NRC/PNL review of the proposed generic resolution of the Owners Group Phase I issues and of the total DR/QR Program for River Bend. Final completion of these NRC staff/PNL reviews of the generic resolution of Phase I and issues is anticipated by September 1985. Final completion of the NRC staff review of the total DR/QR program at ~~RBS~~ River Bend is anticipated by the first refueling outage. However, the staff and its PNL consultants find that these reviews have progressed sufficiently ~~such~~ so that all significant issues warranting priority attention as a basis for issuance of an operating license for ~~RBS~~ River Bend have been resolved.

(2.1)

~~3.1~~ Engine Tests and Inspections

PNL's review of the engine test and inspection program at RBS is provided in Section 4 of ~~the enclosed TER~~ Appendix M. PNL concludes that the test program conducted by GSU and other TDI engine owners was adequate to identify problems with engine components and that tests were adequate to verify component ability to meet the load and service requirements. PNL also finds that component upgrades at ~~RBS~~ River Bend were responsive to the Owners Group recommendations.

The NRC staff concurs with these findings and notes the following:

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- Detailed disassembly and inspection of the ~~RBS~~ River Bend engines as part of the DR/QR effort were performed ~~prior to~~ before preoperational testing. This differs from the staff position taken in Section 4.6 of the staff's generic Safety Evaluation of the Owners Group Program Plan which called for such inspections to take place ~~subsequent to~~ after preoperational testing. The staff considers the ~~GSU~~ applicant's approach to be acceptable on the basis that these inspections were intended to verify the "as-manufactured" quality of the ~~RBS~~ River Bend engines rather than to verify design adequacy. The adequacy of the component designs to perform their intended function and to sustain their loading environments without excessive wear and tear has been evaluated as part of the design review process of the DR/QR program. A major element of this design review effort involved review of relevant operating experience of TDI engines in nuclear and non-nuclear service to identify potential problem areas.

P?

- Preoperational testing was performed for engine loads ranging to the full manufacturer's continuous rating of 3500 KW. Because this exceeds the qualified load rating (3130 KW) of the ~~RBS~~ River Bend crankshafts, the staff was concerned about the potential for inducing cracks in

the crankshafts during the preoperational testing. At the staff's request, ~~GSU~~ the applicant conducted an inspection of the three most highly loaded crankpins in one engine, SD 1A, by fluorescent liquid penetrant and eddy current subsequent to preoperational testing. That inspection was witnessed by one of the PNL consultants and revealed no evidence of fatigue crack initiation (see Section 5.3.5 of ~~enclosed TER~~ Appendix M).

- The exception taken by ~~GSU~~ the applicant against performing the ~~two~~ 2-hour overload test in accordance with ~~Section~~ Position C.2.a(3) of ~~Regulatory Guide~~ RG 1.108 is acceptable to the staff. The 3500-~~KW~~ load at which the preoperational tests were conducted exceed the maximum continuous emergency service loads which would ever be experienced. The 2-hour overload test would provide little if any added assurance of the capability of the engines to operate at 3130-~~KW~~ qualified load level and might, at the same time, contribute unnecessary wear and tear on the crankshafts.

(7.2)

~~3.2~~ Component Problem Identification and Resolution

Stet

Section 5 of ~~the enclosed TER documents~~ Appendix M PNL's review of ~~GSU's~~ the applicant's actions to upgrade and/or qualify the 16 engine components known to have had significant problems (Phase I components). The PNL evaluation also considered the pertinent Owners Group Phase I reports addressing the operating history for each component, Owners Group studies regarding the causes of previous problems, and adequacy of the components to meet functional requirements, and Owners Group recommendations regarding needed component upgrades, inspections, and testing.

On the basis of ~~Based on~~ this evaluation, the NRC staff and PNL have concluded that each of the Phase I components in the River Bend ~~RBS~~ engines is adequate to perform its intended function at a "qualified" load rating of 3130 kW. This finding is subject to implementation of an acceptable engine maintenance and surveillance program as identified below. in Section 5.3.1(2.4). ~~3.4 of this report.~~

Sect 3.4?

With respect to crankshafts, PNL has concluded in Section 5.3.5.3 of Appendix M ~~the enclosed report~~ that the FaAA and FEV analyses substantiate the adequacy of the crankshafts for operation to 3130 kW. As noted by PNL, extensive testing of the Shoreham engines and the absence of any evidence of cracks in the River Bend ~~RBS~~ SD 1A crankshaft following preoperational testing provide additional evidence of the adequacy of the River Bend ~~RBS~~ crankshafts. On this basis, the staff concludes that a confirmatory test for 10^7 cycles is not needed to support 3130 kW as the qualified load of the River Bend ~~RBS~~ engines.

(2.3) ~~2.3~~ Resolution of Open Issues Identified by PNL

In Section 5.0 of Appendix M, ~~the enclosed PNL report~~, PNL recommended implementation of the following actions pertaining to Phase I components before ~~prior to~~ is issued ~~issuance of~~ an operating license:

(a) ~~(1)~~ ~~Visual Inspection of~~ The idler gear on SD 1A should be visually inspected.

(b) ~~(2)~~ Preload torque on all connecting rod bolts should be verified to be in accordance with TDI recommendations.

(c)

~~(3)~~ ~~Visual inspection should be performed on~~ The turbocharger bearings and nozzle ring of SD 1B should be visually inspected and ~~that~~ a liquid penetrant test should be performed on welds retaining the core plug (hub nut) of both SD 1A and 1B. Verify that TDI SIM 300 has been implemented and that the hub nuts have been staked on both engines.

(d)

~~(4)~~ Replacement jacket water pumps with modifications recommended by the Owners Group should be installed.

(e)

~~(5)~~ Owners Group recommended inspections of replacement jacket water pump to be installed on SD 1A should be completed. If cotter pin holes do not line up at the specified torque, the nut washer or nut should be reduced in thickness until the pin holes do match.

(f)

~~(6)~~ Fuel-oil injection tubing which did not meet Owners Group acceptance criteria should be replaced with acceptable tubing.

Subsequent to preparation of ~~the enclosed PNL report~~ appendix M, ~~GSU~~ the applicant submitted an updated inspection report by letter dated June 21, 1985. ~~Based on a~~ On the basis of a review of ~~their~~ the applicant's submittal, the staff concludes that each of the above items has been successfully closed out. In the case of the turbocharger thrust bearings, signs of wear were observed following 100 engine starts. Although the bearings were observed to remain in an operable condition, ~~GSU~~ the applicant elected to replace ~~these bearings~~ them.

In Section 5.7.5 of ~~the enclosed PNL report~~ Appendix M, PNL recommended that liquid penetrant tests be performed on the rib area near the wrist pin, and on the rib at the intersection of the wrist pin boss for all piston skirts from at least one engine. However, PNL concluded that these inspections could be delayed until the first major engine overhaul or earlier when the pistons become available for inspection. ~~prior thereto.~~ This item corresponds to an Owners Group recommendation, yet it appears to the staff to have been omitted from a computerized listing of the ~~GSU~~ applicant's status relative to each Owners Group recommendation which was provided to the staff by letter dated May 3, 1985, ~~with an~~ and updated ~~letter dated~~ on June 26, 1985. Although not an immediate issue with respect to issuance of an operating license, the staff will require that ~~GSU~~ the applicant address this issue ~~prior to~~ before the staff issues its ~~issuance of the staff's~~ final evaluation of the DR/QR program at ~~RBS.~~ River Bend. The staff will also require at that time, that ~~GSU~~ the applicant have completed a QA check to verify the completeness and accuracy of tracking system, implementing, and procedural documents relating to the implementation of all Owners Group recommendations in Appendix I of the DR/QR report. ~~Where GSU is taking~~ Whenever the applicant takes exception to an Owners Group recommendation, ~~this~~ the staff should be ~~reported to the NRC staff with~~ informed about the exception and appropriate justification, should be offered.

(2.4)

~~3.4~~ Engine Maintenance/Surveillance Program

The NRC staff and PNL have identified development of an appropriate maintenance and surveillance (M/S) program to be a key aspect of the overall effort for establishing the reliability and operability of TDI

engines. ~~GSU~~ The applicant has agreed to implement the M/S program identified in Appendix II of the RBS DR/QR Report, Revision 1 (see ~~GSU~~ the applicant's letter dated May 17, 1985). Appendix II of the DR/QR Report presents a schedule of M/S procedures recommended by the Owners Groups for implementation at ~~RBS~~ River Bend.

~~Based on~~ On the basis of its evaluation of Appendix II, PNL has made a number of recommendations which are identified in Section 6 of ~~the enclosed PNL report~~ Appendix M. These recommendations address the maintenance items, operational surveillance, and standby surveillance. PNL notes that its recommendations are intended to augment the M/S plan for ~~RBS~~ River Bend rather than to supplant it.

By letter dated July 29, 1985, ~~GSU~~ The applicant committed to incorporate the PNL recommendations into its M/S program by August 30, 1985, with the exception of some of the PNL recommendations shown in Table 6.3 of ~~the enclosed PNL report~~ Appendix M. ~~GSU~~ The applicant has proposed a revised table shown as Table 8.1 of this ~~SSER.~~ supplement. The proposed changes include deletions of PNL recommendations to perform a visual check every ~~eight~~ 8 hours of starting air pressure, lube oil temperature, jacket water temperature, lube oil sump level, and fuel oil day-tank level. ~~GSU~~ The applicant would continue to log each of these parameters every 24 hours as recommended by PNL, ~~With the exception~~ except that only inlet (rather than inlet and outlet) temperatures would be logged for lube oil temperature. Furthermore, each of the subject parameters has an associated annunciator. ~~GSU~~ The applicant will test the annunciators every 24 hours rather than every ~~eight~~ 8 hours as recommended by PNL. It is the staff's overall

Supply Table 8.1

alarm?

judgment that ~~GSU's~~ the applicant's proposal will not result in a significant reduction in the effectiveness of the ~~RBS~~ River Bend standby surveillance program, and is therefore, acceptable.

At the NRC staff's request, ~~GSU~~ the applicant also committed to incorporat~~ing~~e the following items into its M/S program by August 30, 1985:

(a) ~~(1)~~ ~~O~~perational and surveillance practices identified in ~~GSU's~~ the applicant's letter dated June 12, 1985, concerning the monitoring of engine speed, exhaust gas temperatures, and generator frequency.

(b) ~~(2)~~ ~~A~~dditional PNL M/S recommendations discussed in Section 5 of ~~the enclosed PNL report~~ Appendix M and listed below:

(i) ~~(a)~~ idler gear assembly~~:~~ Owners Group recommendation to clean idler gear and hub mating surfaces should be incorporated into the ~~RBS~~ River Bend maintenance and surveillance program if it has not already been done ~~so~~. This item was not included in the Appendix II summary of the DR/QR report, although it was identified in Appendix I.

?2 idler gear assembly

(ii) ~~(b)~~ idler gear assembly~~:~~ ~~GSU~~ the applicant should verify that proper torque specifications are incorporated into the maintenance/surveillance program. There appears to be a discrepancy between Appendix I (80 ± 20 ft - ~~1~~b) and Appendix II (70 ± 20 ft - ~~1~~b) of the DR/QR report. use l not numeral

60-100

50-90

(iii) ~~(c)~~ push rods: ~~a~~ For future purchases of push rods, ~~GSU~~ the applicant should perform destructive verification of weld quality by sectioning random samples from each manufacturing lot.

Finally, the ~~GSU~~ applicant has also agreed to perform a QA check of implementing and procedural documents pertaining to the maintenance and surveillance program to ensure the completeness and accuracy of these documents relative to the recommendations of the Owners Groups and PNL. ~~GSU~~ The applicant will complete this check by August 30, 1985.

~~Based on~~ On the basis of the above, the staff concludes that the ~~GSU~~ applicant's M/S program for engines 1A and 1B at RBS is acceptable. Furthermore, the staff finds that no exception to GDC ~~#~~17 will be needed to support issuance of a license for fuel load ~~prior to~~ before completion of the aforementioned actions by August 30, 1985. This is ~~due to the fact that~~ because the applicant GSU has completed a comprehensive program of engine inspections, testing, and component upgrades which ensure that the engines are in a good and operable condition. The actions to be completed by August 30, 1985, will ensure the adequacy of the plant M/S program to continue to maintain the engines in an operable and reliable condition over the life of the plant.

It is reasonable to expect that certain changes to the M/S program may become appropriate in the future based on operating experience. The staff will require that any changes to the M/S program be subject

to the provisions of 10 CFR 50.59. In addition, NRC staff/PNL conclusions relating to the adequacy of the crankshafts, engine blocks, and cylinder heads are particularly dependent on certain periodic inspection and/or surveillance checks. Thus, the following elements of the M/S program will be license conditions:

(a)

~~(1)~~ Crankshafts shall be inspected as follows:

fill lines

SD 1B: During the first refueling outage, inspect the fillets and oil holes of the three most heavily loaded crankpin journals (Nos. 5, 6, and 7) with fluorescent liquid penetrant and eddy current as appropriate.

#

SD 1A and 1B: During the second and subsequent refueling outages, inspect the fillets and oil holes of two of the three most heavily loaded crankpin journals in the manner just mentioned.

#

SD 1A and 1B: During each major engine overhaul, inspect the fillets and oil holes of the two main bearing journals between crankpin Nos. 5, 6, and 7, using fluorescent liquid penetrant and eddy current as appropriate. This inspection is to be performed in addition to the crankpin inspections.

(b)

~~(2)~~ Cylinder blocks shall be inspected at intervals calculated using the cumulative damage index (DCI) model and using inspection methodologies described by Failure Analysis Associates, Inc. (FaAA)

JR

in its report entitled "Design Review of TDI R-4 Series Emergency Diesel Generator Cylinder Blocks" (FaAA -84-9-11.1), dated December 1984. ~~Liquid penetrant~~ Inspect cylinder liner loading area using liquid penetrant any time liners are removed. Visually inspect daily between adjacent cylinder heads and the general block top during any period of continuous operation following automatic diesel generator startup.

(c)

~~(3)~~ The ~~licensee~~ applicant shall roll the engines over with the air-start system ~~prior to~~ before any planned starts, unless that planned start occurs within ~~four~~ 4 hours of a shutdown. In addition, after engine operation, the engines shall be rolled over on air after ~~four~~ 4 hours but no more than ~~eight~~ 8 hours after engine shutdown and then rolled over once again approximately 24 hours after each shutdown. In the event an engine is removed from service for any reason other than the rolling over procedure ~~prior to~~ before expiration of the ~~eight~~ 8-hour or 24-hour periods noted above, that engine need not be rolled over while it is out of service. Once the engine is returned to service, the ~~Licensee~~ applicant shall roll it over with air once at the time that it is returned to service. Any head which leaks ~~due to~~ because of a crack shall be replaced.

(2.5)

~~3.5~~ Additional Reporting Requirements

Except as noted below, the staff is not imposing additional reporting requirements pertaining to the TDI diesel engines at ~~RBS~~ River Bend beyond what is already required in the regulations (e.g., ~~Parts~~ 10 CFR 21, 10 CFR 50.72, and 10 CFR 50.73), and by the plant Technical Specifications. The exceptions involve any cracks which may be found in the crankshaft or in the engine block between stud holes of adjacent cylinders. Either of these unexpected situations could involve a potentially serious concern regarding the future operability of the engine. In these cases, the staff will require by condition of the license that any proposed resolution be approved by the NRC staff ~~prior to~~ before returning the engine to an "operable" status. ?

(2.6)

~~3.6~~ Load Restriction Requirements

SRP? FSAR?

The plant Technical Specifications will limit surveillance testing of engines 1A and 1B pursuant to Section 4.8.1.1.2 of plant Technical Specifications to within a load range of 3030 ~~KW~~ to 3130 ~~KW~~ consistent with the qualified load rating of the engines.

Engine operating procedures, operator training, alarms, etc., to minimize the potential for overloading the engines beyond 3130 ~~KW~~ are addressed in the next section of this ~~SER~~ supplement (8.3.1(2.7)). The staff will require that the following actions be performed in the event that the engines should be operated in excess of an indicated 3130 ~~KW~~ ~~(1)~~:

? next section

~~(1)~~ Momentary transients (not exceeding 5 seconds) ~~due to~~ that result from changing bus loads need not be considered as an overload.

~~(2)~~ If there are multiple overload events within a given load range since the previous crankshaft inspection, then the time period criterion applies to the total accumulated time in that load range.

(a) For indicated engine loads in the range of 3130 ~~KW~~ to 3200 ~~KW~~ for a period less than ~~two~~ 2 hours**~~(2)~~, no additional action shall be required.

(b) For indicated engine loads in the range of 3130 ~~KW~~ to 3200 ~~KW~~ for a period equal to or exceeding ~~two~~ 2 hours†~~(3)~~, a crankshaft inspection pursuant to ~~item d)~~ 4 (below) shall be performed at the next refueling outage.

(c) For indicated engine loads in the range of 3200 ~~KW~~ to 3500 ~~KW~~ for a period less than 1 hour~~(3)~~†, a crankshaft inspection pursuant to item ~~d)~~ 4 (below) shall be performed for the affected engine at the next refueling outage.

(d) For indicated engine loads in the range of 3200 ~~KW~~ to 3500 ~~KW~~ for periods equal to or exceeding ~~one~~ 1 hour~~(3)~~†, and for engine loads exceeding 3500 ~~KW~~ for any period of time, ~~(1)~~ a the engine shall be removed from service as soon as safely possible, ~~(2)~~ b the engine shall be declared inoperable, and ~~(3)~~ c the crankshaft shall be inspected. The crankshaft inspection shall include crankpin journal numbers, 5, 6, and 7 (the most heavily loaded), and the two main journals in between using fluorescent liquid penetrant and eddy current testing as appropriate.

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†~~(3)~~ if there are multiple overload events within a given load range, criterion applies.

In Section 2.0 of ~~the enclosed TER~~ Appendix M, PNL has recommended that fast starts be limited to the number consistent with NRC requirements in order to further minimize wear and tear of the EDGs. Consistent with the staff's position on the frequency of fast starts as identified in NRC Generic Letter 84-15, the plant Technical Specifications, Section 4.8.1.1.2.a, will limit fast starts from ambient conditions during surveillance tests to at least once per 184 days. All other engine starts and loading associated with surveillance testing in Section 4.8.1.1.1.2.a may be preceded by an engine prelube period and/or other warmup procedures recommended by the manufacturer.

Ron chrono?

(2.7) ~~3.7~~ Operating Procedures

In a NRC staff letter dated July 23, 1985, ~~GSU~~ the applicant was ~~requested~~ asked to develop procedures which provide proper guidance and instruction to operators against overloading the TDI diesel generators above the qualified load level. The staff stated that these procedures should address, but not necessarily be limited to, the following:

(a) ~~(1)~~ No single operator error should cause the loading of more than one TDI engine in excess of its qualified load rating.

(b) ~~(2)~~ Procedures and training in place at River Bend should preclude operator action that would cause the TDI EDG load to exceed the qualified load.

(c) ~~(3)~~ The training program should adequately address the technical concerns associated with the qualified load limit on the TDI EDGs.

(d)

~~(4)~~ If a situation were to occur that would, for some unspecified failure, cause the EDG to exceed the qualified load, the procedures and training should provide the necessary guidance to reduce the load below the qualified load within ~~one~~ 1 hour.

(e)

~~(5)~~ Distinctive and unique instrumentation and alarms should be installed to warn operators when the engines are loaded above the qualified load.

The applicant ~~GSU~~ has agreed by letter dated July 29, 1985, to review its procedures and to make any necessary changes ~~prior to~~ before plant criticality pursuant to ~~the~~ above criteria. The applicant ~~GSU~~ further noted that instrumentation and alarms with a distinctive sound have already been installed to warn operators if the engine loads exceed 3130 kw. ~~Based~~ On the basis of ~~of~~ these actions, the staff concludes that the ~~BBS~~ River Bend operating procedures for the TDI engines will provide the appropriate guidance and instruction to operators.

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Annunciation

(3)

~~4.0~~ Conclusions

This ~~SER~~ supplemental evaluation and the ~~enclosed~~ appended PNL evaluation precede final completion of the NRC/PNL review of the proposed generic resolution of the Owners Group Phase I issues and of the total DR/QR program at River Bend. The NRC staff and PNL conclude that these reviews have progressed sufficiently ~~such~~ so that all significant issues warranting priority attention as a basis for issuance of an operating license for River Bend have been adequately resolved.

?

to be more specific

Accordingly, the NRC staff concludes that the TDI diesel generators at ~~RBS~~ River Bend will provide a reliable standby source of onsite power in accordance with ~~General Design Criterion~~ GDC 17. This finding is subject to (1) license conditions identified in Section ~~3.4~~ 8.3.1(2.4) of this ~~SSER~~ evaluation pertaining to the engine maintenance/surveillance (M/S) program, (2) special reporting requirements identified in Section ~~3.5~~ 8.3.1(2.5), (3) loading restriction requirements as identified in Section ~~3.6~~ 8.3.1(2.6), and (4) a license condition making operation beyond the first refueling outage subject to NRC staff approval based on the staff's final review of the Owners Group generic findings and of the overall DR/QR program at River Bend. This finding is also based in part upon ~~GSU~~ the applicant's commitments in its letter dated July 29, 1985, to complete the following actions:

Sec. 3.4?

Sec 3.5 - 3.6

Sec 3.4

(1) Incorporate additional items identified in Section ~~3.4~~ 8.3.1(2.4) of this SSER into the M/S program for EDGs 1A and 1B by August 30, 1985.

(2) Perform QA check to ensure completeness and accuracy of implementation and procedural documents relating to the M/S program for EDGs 1A and 1B by August 30, 1985 (see Section ~~3.4~~ 8.3.1(2.4) of this SSER).

(3) Review and revise as necessary EDG 1A and 1B operating procedures as described in Section 3.7 of this SSER 8.3.1(2.7) ~~prior to~~ before plant criticality.

8.3.2 DC Power Systems

In FSAR Amendment 19, the applicant deleted a listing of much of the Division III instrumentation which is used to monitor the status of the Division III dc system and which the staff had previously reviewed and found acceptable. It appeared that this might have been an unintentional editorial error. FSAR Amendment 21 reinstated the instrumentation which had been deleted. This, therefore, is acceptable.

In a letter dated July 15, 1985, the applicant provided a proposed FSAR amendment which revised the Division III (HPCS) battery loading profile and changed the resulting battery endurance from 4 hours to 2 hours. The staff has reviewed these changes and finds them acceptable. The River Bend Technical Specifications have incorporated the revised information in Section 3/4.8.2.1.

8.4 Other Electrical Features and Requirements for Safety

8.4.1 Adequacy of Station Electric Distribution System Voltages

(1) In Section 8.4.1(1) of the SER, the staff stated it would confirm the adequacy of the final relay setpoints for the second level undervoltage protection. In a letter dated July 24, 1985, the applicant provided the setpoint calculations for the first and second levels of undervoltage protection. The setpoints for the Division I and II vital buses are 2970 V (74.3% of equipment-rated voltage) for the first level and 3740 V (93.5% of equipment-rated voltage) for the second level. The setpoints for the Division III vital bus ~~is~~ are 3045 V (76.1% of equipment rated voltage) for the first level and 3777 V (94.4% of equipment rated voltage) for the second level. The staff has reviewed these setpoints and their tolerances provided in the applicant's letter and finds them acceptable. Therefore, Confirmatory Item 46 is closed.

FSAR Amendment 19 revised figures ~~which~~ that indicate the Division III undervoltage protection logic is not arranged in the 2-out-of-3 coincidence logic as described in the applicant's March 5, 1984, letter and reported in

the SER. FSAR Amendment 21 provided a revised response to the description of the Division III (HPCS) first and second levels of undervoltage protection. The first and second level undervoltage protection scheme senses voltage at the incoming side of the normal supply breaker. The first level of undervoltage protection is arranged in a 1-out-of-2 logic with a time delay of approximately 2 seconds.

The second level of undervoltage protection is arranged in a 2-out-of-2 coincidence logic and utilizes two separate time delays. The first is approximately 10 seconds (to override motor starting transients). Following this delay, an alarm in the main control room alerts the operator to the degraded condition. The subsequent occurrence of a LOCA signal immediately separates the Division III bus from the offsite power system. The second delay is approximately 60 seconds. After this delay, if the operator has failed to restore adequate voltages, the Class 1E system is automatically separated from the offsite power system. The 2-out-of-2 coincident logic used for the second level undervoltage protection allows one relay to be taken out of service for test and calibration while an effective 1-out-of-1 protective logic is retained. The staff finds that the design of the second level undervoltage protection as described above satisfies the provisions of Branch Technical Position (BTP) PSB-1 and is, therefore, acceptable. Therefore, Confirmatory Item 46 is closed.

(4) The staff indicated in Section 8.4.1(4) of the SER that it would confirm the adequacy of the applicant's verification tests. These tests have not yet been completed. The staff will review and provide its confirmation of the acceptability of these tests and their results in a future SER supplement when the results are available, but no later than before startup from the first refueling outage.

8.4.2 Containment Electrical Penetrations

FSAR Amendments 19 and 20 provided some revisions to the description of the containment electrical penetration protection at River Bend. For low-voltage control circuits, a category of circuits was added that had been analyzed and found not to require backup protection. These circuits are current transformer

leads used on differential protection circuits, and trip coil circuits in circuit breakers. In a letter dated July 24, 1985, the applicant provided justification for the lack of protection on these circuits. The current transformer leads on differential protection circuits are acceptable because a high current exists on these circuits only momentarily when a fault is sensed and is quickly cleared by the differential protection circuit. An open circuit on the current transformer secondary which could cause high voltages will also cause a trip of the protection circuit which will in turn eliminate the overvoltage. The lack of redundant protection on trip coil circuits is acceptable because these circuits are fed from an ungrounded 125-V dc power supply, and the portion of the circuit passing through the penetration is confined to only one leg (positive or negative) of the power supply. The only type of failure the penetration circuit would be exposed to is an electrical ground which would not cause fault current to flow unless there ~~was~~ were a simultaneously existing fault on the opposite leg of the power supply. This is unlikely to occur because a ground-detection alarm is provided on the 125-V dc system which alerts the operator to the existence of the first ground on the system so that he may track down and remove it to maintain the system ungrounded.

Another revision to the penetration protection is the addition of a category of low-voltage control circuits which are deenergized during plant operation. With the exception of the emergency response facility (ERF) system (portable equipment installed during shutdown), the equipment in this category will all be listed in the River Bend Technical Specification to ensure they remain deenergized during plant operation. If the circuits have provisions for locking them in the deenergized state, they will also be locked open. These provisions are acceptable. The other remaining electrical penetration revisions made in FSAR Amendments 19 and 20 have been reviewed and are also acceptable. Therefore, Confirmatory Item 71 is closed.

8.4.5 Physical Identification and Independence of Redundant Safety-Related Electrical Systems

In Section 8.4.5 of the SER, the staff stated that 4.16-kV/13.8-kV cabling in conduit is not routed in close proximity to Class 1E ladder-type trays except where the cables exit from the subject tray. This statement was based on a similar statement in FSAR Chapter 8. FSAR Amendment 20 has subsequently deleted this statement. The staff has reviewed the separation details for these circuits contained in River Bend drawings 12210-EE-34ZE-7 and 12210-EE-34ZH-6 and finds that they comply with the requirements of IEEE Std. 384 and RG 1.75 and are, therefore, acceptable.

In a previous supplement (SSER 2), the staff evaluated the use of red- and blue-colored jacketed cables in unscheduled non-Class 1E circuits (these colored cables are normally only used to identify Class 1E circuits), and found them acceptable with the restrictions outlined in FSAR Amendment 16. FSAR Amendment 20 has added additional categories where these cables are used. These are in direct-burial cable installations and inside the makeup water intake structure, in various types of raceways, where there are only non-safety-related circuits. The FSAR states that there are no safety-related Category I circuits at these locations, and no safety-related circuits are installed in direct-burial cable trenches. The staff finds that these exceptions to cable color coding will not decrease the effectiveness of the color-coding system used at River Bend and are, therefore, acceptable.

8.4.6 Non-safety Loads on Emergency Sources

In SSER 2 the staff stated a need to review the applicant's evaluation with regard to the acceptability of non-Class 1E slide wire transducers and limit switches. In a letter dated July 5, 1985, the applicant provided its evaluation. For the slide wire transducers, a qualified resistor limits the available fault current to a small value which has no detrimental effect on the Class 1E power supply should a short or ground occur on the unqualified transducer. For the limit switches, a short or a ground on the limit switch is the same as if the switch were closed, which also has no detrimental effect on the

Class 1E power supply. Both the slide wire transducer and limit switch circuits as designed are, therefore, acceptable.

In FSAR Amendment 20, the applicant added non-Class 1E motor heaters to the list of non-Class 1E loads powered from Class 1E power supplies. The motor heaters are powered from a Class 1E 120-V panelboard. There is a single Class 1E circuit breaker in the 120-V feed to the motor heater. In a letter dated July 5, 1985, the applicant stated that for Westinghouse motors the heater is qualified Class 1E and for Reliance motors the heaters are also considered to be Class 1E. For Seimens-Allis motors, the applicant has committed to install a second overcurrent protection device in the 120-V feed to the motor heater. In the interim, the applicant has committed to keep these circuits deenergized. Section 3/4.8.4.4 of the River Bend Technical Specifications requires that upon installation of the second overcurrent protective device, the circuit breakers in the circuit be listed in the Technical Specifications and they be periodically tested. With these provisions, the staff finds this item acceptable. Therefore, Confirmatory Item 49 is closed.

9 AUXILIARY SYSTEMS

9.2 Water Systems

9.2.5 Ultimate Heat Sink

In FSAR Amendment 16, the applicant identified a reduction of the diesel generator loading resulting from delayed starting of the ultimate heat sink (UHS) fans based on the ultimate water temperature rise in the UHS basin. In order to ensure that the basin water temperature would not rise above the design ambient temperature, the applicant, in a submittal dated May 20, 1985, committed to have installed before startup following the first refueling outage a UHS basin temperature monitoring system. This system is to determine the average basin water temperature with a continuous readout and alarm in the control room. The applicant has stated that because of the time needed to design, procure, install, and test the temperature-monitoring system, installation of the monitoring system cannot be completed before power operation. By submittal dated July 18, 1985, the applicant committed to provide the design of the temperature monitoring system for staff review and approval before its installation.

As an interim measure, the applicant has committed to manually taking daily basin water temperature readings with an increasing frequency based upon the actual water temperature. At a water temperature between 75°F and 80°F, the reading will be taken every 4 hours; when the water temperature exceeds 80°F, the reading will be taken every 2 hours. The UHS and the standby service water system are declared inoperable when the basin water temperature reaches 82°F. The basis for the deferral of the installation of the UHS basin water temperature monitoring system is the staff's judgment that the interim procedures provide a level of safety comparable to the design of the new system for the short period of operation of one cycle.

On the basis of its review, the staff concludes that the UHS design is acceptable pending the following conditions:

(1) The applicant will submit the design of an acceptable temperature-monitoring system for staff review before the first refueling.

(2) The applicant will have installed the temperature-monitoring system and proposed modification to the Technical Specifications (both to delete the interim Technical Specifications and to incorporate the new design into the Technical Specifications) before startup after the first refueling outage.

In FSAR Amendment 20 and the July 18th submittal, the applicant provided the design of a new system to be installed within the UHS. The new system is a hypochlorite feeding the recirculation system. In the submittal dated July 18, 1985, the applicant stated that the hypochlorite feeding system is designed to control organic growth in the UHS. A concentration level of 3.0 to 5.0 ppm of free chlorine will be injected into the UHS basin and verified by sample analysis when (1) makeup water is added to the UHS, (2) the standby service water

system is operated or tested, or (3) microbological growth is detected. This system consists of a hypochlorite feed tank, a positive displacement feed pump, a recirculation pump, and piping. The piping in the UHS is plastic, except for the piping near the standby service water pumps. The hypochlorite system is designed to inject 25 gpm of sodium hypochlorite into the UHS for about 2 hours per day for 3 days per week to maintain the minimum chlorine level in the UHS. This system is not safety related and failure of this system will not adversely affect the UHS or the standby service water system. Thus the requirements of General Design Criterion (GDC) 2, "Design Basis for Protection Against Natural Phenomena," and guidelines of RG 1.29 (Rev. 3), Position C.2, are satisfied.

In FSAR Amendment 16, the applicant modified the operation of the UHS fans from automatic initiation with the starting of the diesel generators to manual initiation from the control room 2 hours into design-basis accidents in order to reduce the diesel generator loadings. The applicant indicated in a submittal dated May 14, 1985, that manual initiation of the fans 2 hours after the commencement of the design-basis accident would not have any adverse consequences. The applicant indicated that the water temperature would rise approximately 2.2F° per hour without the fans operating.

On the basis of the applicant's commitment to install a UHS basin water-temperature-monitoring system, the license condition, the installation of a seismic Category I, Class 1E, basin water temperature monitoring system by the first refueling outage, and the interim measures, the staff concludes that manual initiation of the UHS fans before basin water temperature reaches 82°F is acceptable. Therefore the requirements of GDC 44, "Cooling Water," as related to the ability of the UHS to accept the heat rejected by the plant, are satisfied.

On the basis of the above evaluation, the staff concludes that the UHS meets GDC 2 and 44, as related to protection against natural phenomena and the capability to reject the heat loads from safety-related components under emergency conditions including a single active failure, and is, therefore, acceptable. The UHS meets the acceptance criteria of SRP Section 9.2.5.

9.2.7 Standby Service Water System

In its SER, the staff stated that each loop of the standby service water system (SSWS) is powered from its associated diesel. The A and C SSWS pumps in the A loop are powered from the Division I diesel generator and the B and D SSWS pumps in the B loop are powered from the Division II diesel generator. In FSAR Amendment 16, the applicant removed the C SSWS pump and the associated instrumentation and controls from the Division I diesel generator and proposed powering it only from the Division III (HPCS) diesel generator. Thus the C SSWS pump only operates when the Division III diesel generator operates.

The applicant provided a failure modes and effects analysis which demonstrates the ability of the SSWS to withstand any single failure and provide sufficient cooling water to ensure a safe shutdown for all design-basis events. The staff has reviewed the revised failure modes and effects analysis and concludes that there is no single failure which will result in insufficient SSWS cooling water.

In its SER, the staff also stated that each SSWS pump was capable of handling 50% of the cooling water for design-basis accidents and, therefore, only two

should occur in

pumps were needed for safe shutdown. Although these pumps are rated as 50% for design-basis accidents, ~~where~~ the single failure ~~is~~ the Division III (HPCS) diesel generator, three pumps are needed for a safe shutdown. This is acceptable because with the single failure of the HPCS diesel generator and the resulting loss of the C SSWS pump, there will still be three SSWS pumps available.

Each SSWS loop returns the cooling water to the ultimate heat sink, which is a forced-draft cooling tower. The Division II-powered pumps return the water to an area of the cooling tower which is served by the Division II fans. The Division I and III-powered pumps return the water to an area of the cooling tower which is served by the Division I-powered fans. A crosstie between the redundant loops enables the A and C SSWS pumps to supply water to the components and systems which would normally be serviced by the B and D SSWS pumps. Because of the independence of the operability of the cooling tower fans and the SSWS pumps, the possibility exists that the SSWS pumps in one loop and the cooling tower fans associated with the other loop may be inoperable concurrently. Thus, the appropriate number of SSWS pumps and fans may be operable, but the "system" may not be able to adequately remove sufficient heat to safely shut down the plant. The applicant has provided an acceptable Technical Specification which requires the two operable SSWS pumps to be aligned to the loop with the two operable cooling tower fans whenever either of the following conditions exists: (1) Two SSWS pumps in the same loop are inoperable and at least one fan in the other loop is inoperable or (2) Two cooling tower fans in the same loop are inoperable and at least one SSWS pump in the other loop is inoperable.

On the basis of the acceptable Technical Specification concerning the alignment of the operable SSWS pumps and the cooling tower fans, the staff concludes that the standby service water system meets GDC 44, as related to the capability of transferring heat loads from safety-related components to the ultimate heat sink under emergency conditions including a single active failure, and is, therefore, acceptable.

9.3 Process Auxiliaries

9.3.3 Equipment and Floor Drainage Systems

In its SER, the staff stated that the floor drains were pumped from the ECCS compartments and safety-related areas to the radwaste system. By FSAR Amendment 20, the applicant has provided a new operating mode for two of the floor drainage systems in the auxiliary building which routes the water to either the suppression pool or to the radwaste system. The areas affected by this change are the reactor plant, closed, cooling-water system; the steam tunnel area which includes the leakoffs associated with the reactor core isolation cooling (RCIC) system; some of the components serviced by the normal/standby service water system; the standby gas treatment system; the floor drains in the auxiliary building crescent area at elevation 70; some unit coolers; MSIV positive leakage control system; HVAC systems for the reactor, auxiliary, turbine, and containment buildings; some compressor/dryer systems; some fire protection sprinkler drains; and miscellaneous area floor drains for such areas as elevators, instrument racks, hatches, and electrical terminal boxes. The auxiliary building crescent area contains emergency core cooling system (ECCS) piping which could leak. Leakage from this piping could reduce the inventory in the suppression pool. ?feet

With this new operating mode, the two affected systems have been identified as the suppression pool pumpback system (SPPS). Since this is only a new operating mode of a previously approved system, the staff concludes that the SPPS meets the requirements of GDC 4, "Environmental and Missile Design Bases." The SPPS consists of two sumps, each of which has two pumps. The pumps, isolation valves, and level-detection instrumentation are seismic Category I and Class 1E powered. The piping from the isolation valves to the suppression pool interface at the high-pressure core spray return line is seismic Category I, Safety Class 2. The rest of the piping is not seismic Category I, but is seismically supported. Therefore, the staff concludes that the SPPS meets the requirements of GDC 2, "Design Basis for Protection Against Natural Phenomena," and the guidelines of RG 1.29, "Seismic Design Classification." The SPPS is operated either manually from the control room or automatically from the level sensors. By installing this new operating mode, the applicant has not deleted the option of pumping the water to the radwaste system. The use of this system to pump the water to the suppression pool provides additional time for the operator to identify the source of leakage while maintaining suppression pool water level and preventing excessive buildup of water in the auxiliary building.

Selection of the option to pump back to the suppression pool is by means of opening a motor-operated valve. Opening this valve automatically closes the air-operated valves to the radwaste system. The air-operated valves are fail-closed valves which prevent inadvertent pumping to the radwaste system during a loss-of-coolant accident (LOCA).

On the basis of the above evaluation, the staff concludes that the SPPS meets the requirements of GDC 2 and 4, with regard to protection against natural phenomena, environmental conditions, and missiles, and the guidelines of RG 1.29., Positions C.1 and C.2, concerning the system seismic classification, and is, therefore, acceptable. The SPPS meets the acceptance criteria of SRP Section 9.3.3.

9.3.5 Standby Liquid Control System

In its SER, the staff concluded that the standby liquid control system was acceptable based, in part, on the similarity between the FSAR Figure 9.3-14 and the GE standard figure which identifies the acceptable bounds of tank volume and sodium pentaborate concentration levels. (This issue is also discussed in Section 4.6 of this supplement.) By FSAR Amendment 20, the applicant provided a revised Figure 9.3-14 which identifies a lower concentration, smaller tank volume, and no safety margin in the total tank storage capacity. On the basis of the staff's independent calculations, the lower concentration level of 9.3% is non-conservative with respect to previously approved concentration and volume levels. The applicant provided a revised figure by submittal dated July 8, 1985, which shows the minimum concentration as 10.5%. This concentration level was compared with other previously approved analyses and found to provide similar boration rates. Therefore, the revised figure provided by the July 8th submittal is acceptable. The applicant has also committed to revise the figure in the Technical Specifications.

The staff concludes that the design of the standby liquid control system meets the requirements of GDC 26, "Reactivity Control System Redundancy and Capability," and GDC 27, "Combined Reactivity Control System Capability," and is,

therefore, acceptable. The functional design of the standby liquid control system meets the applicable criteria of SRP Section 9.3.5.

9.4 Air Conditioning, Heating, Cooling, and Ventilation Systems

9.4.1 Control Building Ventilation System (Control Room Area Ventilation System)

In its SER, the staff stated that the control building ventilation system includes the control building chilled water system. The chilled water system consists of two redundant, closed-loop chilled water trains with each train capable of meeting the total chilled water needs of the control building. Each train contains two 50% capacity electric-motor-driven centrifugal liquid chillers with both trains (all four chillers) powered from the essential service buses so that emergency power is available from the diesel generators if offsite power is lost. By FSAR Amendment 20, the applicant proposed to automatically initiate one of the two water chillers on each train and to automatically start the second chiller upon failure of the lead chiller in the respective ventilation train in order to reduce the electrical loading on the Division I and Division II diesel generators.

In a letter dated May 16, 1985, the applicant has provided the results of an analysis of the control building heat loads assuming the loss of a Division I or Division II diesel generator as the single active failure, for all design-basis events. This analysis indicates that the heat load will be significantly reduced because of the reduction in equipment and instrumentation being powered as a result of the loss of a Division I or Division II diesel generator. (The loss of the Division III diesel generator will have no effect in that it powers no safety-related equipment in the control building.) With both Division I and II diesel generators operating, one 50%-capacity water chiller would be automatically initiated in each train, for a total of 100% capacity, and thereby meet all of the chilled water requirements for the control building. With the single failure of one of the automatically initiated water chillers, the second chiller in the train with the failed chiller would automatically start. If the single failure is a ventilation train, there is sufficient time for the operator to manually initiate the second chiller in the operating ventilation train.

Having one automatically initiated water chiller in each of the two redundant chilled water trains and having the second chiller in each train automatically initiated upon failure of the lead chiller in the respective ventilation train is acceptable. This does not change the staff's conclusions as previously stated in the SER.

9.4.6 Miscellaneous Building Heating, Ventilation, and Air Conditioning (HVAC) Systems

In its SER, the staff stated that there were six miscellaneous building HVAC systems. By FSAR Amendment 20, the applicant added eight more miscellaneous building HVAC systems, as follows:

(7) motor generator building (heating and ventilation system)

(8) demineralized water pumphouse (heating and ventilation system)

(9) circulating water pumphouse and switchgear room (heating and ventilation system)

(10) cooling tower switchgear house (heating and ventilation system)

(11) clarifier area switchgear house (heating and ventilation system)

(12) hypochlorite area switchgear house (heating and ventilation system)

(13) blowdown pit (heating and ventilation system)

(14) auxiliary control building (heating, ventilation, and air conditioning system)

These additional miscellaneous building HVAC systems are located in non-safety-related buildings and are designed to provide a suitable environment for personnel and equipment operation. None of these systems has any safety-related function, nor does failure of any system comprise any safety-related system or components. Failure of any system will not prevent safe shutdown of the reactor. Therefore, no system is designed to seismic Category I standards or to Quality Group A, B, or C standards. Thus, the guidelines of RG 1.29, "Seismic Design Classification," Position C.2, are satisfied and the requirements of GDC 2, "Design Basis for Protection Against Natural Phenomena," are satisfied. These systems are not designed to control release of radioactive material; therefore, GDC 60, "Control Releases of Radioactive Materials to the Environment," is not acceptable.

These additional miscellaneous building HVAC systems meet the requirements of GDC 2 and the guidelines of RG 1.29, Position C.2, and are, therefore, acceptable. These additional systems meet the acceptance criteria of SRP Section 9.4.3.

SSER 3

~~Attachment 1~~

9.5.1

Chemical Engineering Branch/Fire Protection Section
Supplemental Safety Evaluation Report
River Bend Station Unit No. 1
Docket No. 50-458

II. Fire Protection Program Requirements

A. Fire Protection Program

In our SER we stated that the fire protection program is described in the applicant's Fire Protection Evaluation Report (FPER). In fact, the fire protection program is described in Section 9.5-1 and Appendices 9A and 9B of the applicant's Final Safety Analysis Report (FSAR), as opposed to a separate FPER. The SER should be so corrected. This correction does not affect our safety evaluation.

V. General Plant Guidelines

A. Building Design

In our SER we stated that 3-hour fire rated penetration seals are provided for penetrations of fire rated walls and floor/ceiling assemblies in accordance with BTP CMEB 9.5-1, Section C.5.a (3). By letter dated June 28, 1985, the applicant requested deviation from this position to the extent that it requires sealing inside conduits larger than 4 inches in diameter at the fire barrier penetration and sealing inside conduits 4 inches or less in diameter at the barrier unless the conduit extends at least 5 feet on either side of the barrier and is sealed either at the barrier or at both ends. The applicant proposes to seal conduits at the fire barrier or at the first opening on both sides of the barrier regardless of conduit size or distance from the barrier.

By letter dated July 26, 1985, the applicant submitted the results of fire tests on conduits sealed in accordance with the proposal that were exposed to the ASTM E-119 Standard Time Temperature Curve in accordance with the ANI/MAERP test method. The test report also documented the test assembly's performance against the requirements of IEEE 634-78, NFPA 803, and ASTM E814-81.

The fire test demonstrated that conduits sealed in accordance with the applicant's proposal prevent smoke and hot gas propagation through the conduits throughout the 3-hour test period. Moreover, none of the unexposed side thermocouples exceeded the acceptance criteria temperature specified by either ANI/MAERP, IEEE 634-78, or ASTM E814-81.

Following the fire exposure, the test assembly was subjected to 3 hose stream tests. None of the seals were penetrated by water during these tests.

Based on our evaluation, we conclude that the applicant's proposal to seal conduits at the fire barrier or at the first opening on both sides of the barrier regardless of conduit size or distance from the barrier will provide an equivalent level of protection to that

achieved by compliance with Section C.5.a.(3) of BTP CMEB 9.5.-1. The applicant's conduit sealing proposal is, therefore, an acceptable deviation from BTP CMEB 9.5-1, Section C.5.a.(3).

In our SER we stated that radiation shielding materials are non-combustible and met Section C.5.a.(9) of our guidelines. However, in FSAR Amendment 20 the applicant identified eight areas where a combustible material is used for radiation shielding. In all cases, the combustible radiation shielding material is enclosed by steel plates with thicknesses between 1/2 and 3 inches and is, therefore, isolated from ignition sources. Moreover, the material does not expose any safety related or safe shutdown components. Therefore, we have reasonable assurance that the combustible radiation shielding does not present a threat to safe shutdown.

Based on the above evaluation, we conclude that the use of combustible radiation shielding in the eight areas listed in FSAR Amendment 20 is an acceptable deviation from BTP CMEB 9.5-1, Section C.5.a.(9).

By letters dated June 13, 1985 and July 26, 1985 the applicant requested deviations for not completing the fire wrap for cables in the control building before 5 percent power is exceeded, and in the fuel building until the full power operation milestone:

a. In the control building, the fire wrap is for the standby service water. In the event that pumps 1SWP*2B, C and D are not available due to a fire, pump 1SWP*2A is capable of providing all cooling water required for safe shutdown from 5 percent power. Fire zones C2A, B and C have fire detection and suppression. A fire watch will be established until the fire wrapping is completed in accordance with Technical Specifications. We will condition the license to assure that the fire wrap will be installed prior to exceeding 5 percent of rated power. We find this deviation acceptable.

b. In the final building, the fire wrap is for the spent fuel cooling system. The completion of fire wrapping for the Division I and II cabling for the spent fuel pool cooling system is currently scheduled to be completed prior to full power operations. This is well in advance of any anticipated off-loading of spent fuel from the reactor. Therefore the fire protection requirements for wrapping will be completed in advance of the need for the spent fuel pool cooling system. Should there be some unforeseen reason to off-load irradiated fuel prior to achieving full power operation (and prior to completing the installation of the wrap), then a fire watch will be implemented in accordance with the Technical Specifications until the wrapping is complete. No justification has been given for not completing this item before 5 percent rated power is exceeded. We will condition the license to assure that this fire wrap is installed prior to exceeding 5 percent of rated power. We find this deviation acceptable.

B. Fire Protection of Safe Shutdown Capability

In our SER we stated that the applicant was assuming no repairs in order to go to cold shutdown within 72 hours. However, in FSAR Amendment 20, the applicant identified two components that could require repairs. For a fire in the main control room, air compressor 1LSV*C3A may have to be started by use of jumpers at standby motor control center 1EHS*MCC2L if additional air is required for cycling the ADS/SRVs. Since these valves have a qualified air accumulator to provide for cyclic operation, it is anticipated that the air compressor will not need to be jump started until well into the 72 hours, if at all. The second repair is required to maintain cold shutdown. This repair entails either manually opening valve 1E12*F009 or to jumper the valve open at the standby motor control center 1EHS*MCC26, in order to permit operation of the RHR in the shutdown cooling mode. This operation does not need to be performed until near the end of the 72 hour period. The applicant has committed to maintain the materials for these repairs onsite and in a separate fire area and to have procedures in effect to implement these repairs.

Based on the applicant's commitments, the limited number of repairs, and the anticipated amount of time available to make the repairs, we conclude that the repairs to achieve and maintain cold shutdown are acceptable.

During the site audit, we observed that area-wide automatic fire suppression was not provided in the following areas:

ET-1 - Electrical Tunnel
PT-1 - Pipe Tunnel
AB-7 - Auxiliary Building Piping and Electrical Tunnel
C-2A - Control Building Cable Chases
C-2B - Control Building Cable Chases
C-2C - Control Building Cable Chases
C-6 - Control Building, Elev. 70

Each of these areas is equipped with an area-wide fire detection system; a cable-tray fire suppression system; portable fire extinguishers; manual hose stations; and a 1-hour fire rated barrier around one shutdown division. If a fire were to occur in any of the areas, it would be detected in its early stages by the fire detection system. The fire brigade would then extinguish the fire. If room temperatures rose significantly, the cable-tray sprinkler system would activate. Water from this system would protect vulnerable cables and would limit fire spread. During the time delay between the advent of a fire and its eventual control, damage would be confined to this area by the fire-rated perimeter construction. Also, because one shutdown division is protected by a fire barrier, there is reasonable assurance that safe shutdown could still be achieved and maintained. Therefore, area-wide automatic fire suppression is not necessary. Based on our evaluation, we conclude that the absence of area wide fire suppression in the above areas is an acceptable deviation from Section C.5.b of BTP CMEB 9.5-1.

C. Alternate Shutdown Capability

The lighting for the control room and the remote shutdown panel area are Class IE, however, there are operator actions which are required in the event of a control room fire that are neither in the control room nor in the remote shutdown panel area. The applicant has provided eight hour battery powered lights for other areas. In a submittal dated June 11, 1985, the applicant has committed to perform all operator actions which are not performed in the main control room or at the remote shutdown panel area within eight hours. The only exception is the operation or repair of valve 1E12*F009 an RHR isolation valve. The operation of this valve is not necessary until approaching cold shutdown. The guidelines identified the need to be able to be in cold shutdown in 72 hours, thus this valve need not be operated for approximately 68 hours after the fire. This is sufficient time for the operators to use portable lights, as necessary, to locate and operate the valve. Therefore, we conclude that operation of valve 1E12*F009 after the eight hours of emergency lighting is acceptable.

In a submittal dated July 19, 1985, the applicant stated that all circuits necessary for alternate shutdown from outside of the control room are in compliance with the guidelines of I & E Bulletin 85-09. Compliance with the guidelines of the bulletin is based on having fuses in the circuits which are separately fused and isolated from the control room circuits in order to safely shutdown the plant in the event of a main control room fire.

Based on meeting the guidelines of I & E Bulletin 85-09 and on the applicant's commitment to complete the necessary operator actions within eight hours, we conclude that the alternate shutdown capability is acceptable and complies with the guidelines of Section 9.5.1 of the Standard Review Plan.

By letter dated May 28, 1985, the applicant requested deviations for not completing the alternate shutdown system for the control room until the 5 percent power milestone. In this letter, the applicant stated that the modifications necessary for alternate shutdown in the event of a control room fire would not be completed before receiving a license because of the time required to procure, install, and test the modifications. These modifications include installing 22 transfer and control switches, revising plant procedures, and re-training operators. By letter dated June 13, 1985, the applicant stated that the plant will be in compliance with the guidelines of the BTP CMFB 9.5.1 Section C.5.6 with respect to alternate shutdown prior to exceeding 5 percent power. Based on the alternate shutdown not being available in the event of a fire in the main control room, we require that a condition be placed on the license, as follows:

The applicant shall complete all modifications to provide a means to safely shutdown the plant, in the event of a fire in the main control room, from outside of the control room, including revision of the plant procedures and re-training of the operators, prior to exceeding 5 percent of rated power.

The applicant has committed to station a continuous fire watch in the control room at core load until the alternate shutdown system is fully completed and operational.

Operation of the plant up to 5 percent or rated power will not involve significant fission product inventory; therefore, the risk to the health and safety of the public is not increased. Moreover, because the applicant has committed to station a continuous fire watch in the control room, we find that adequate interim fire protection measures have been provided. Therefore, the applicant's request for deviation from our guidelines should be granted. The alternate shutdown system for the control room should be completed prior to exceeding the 5 percent power milestone.

VI. Fire Detection and Suppression

A Fire Detection

In our SER we stated that the fire detection system is designed in accordance with NFPA 72D, "Standard for the Installation, Maintenance, and Use of Proprietary Protective Signaling Systems." Information was not available during one site visit to verify this requirement. By letter dated June 28, 1985, the applicant verified that the system had been tested and found acceptable for listing by Underwriters Laboratories, Inc. We find this acceptable.

B. Fire Protection Water Supply System

In our SER we stated that the fire pump installation was designed and installed in accordance with NFPA 20, "Standard for the Installation of Centrifugal Fire Pumps." During our site audit, we observed that butterfly valves were installed in the suction lines to the fire pumps. The use of butterfly valves in fire pump suction lines is not in accordance with NFPA 20. The applicant verbally committed to replace the butterfly valves with approved OS&Y valves. By letter dated June 28, 1985, the applicant informed us that all of the butterfly valves installed in the fire pump suction lines were replaced with OS&Y valves in accordance with NFPA 20. We now consider this item closed.

In our SER we also stated that in addition to a fire service jockey pump, the fire protection water supply system has a hydro-pneumatic tank to maintain system pressure. In fact, the system does not have such a tank. We find that the fire service jockey pump along is adequate to maintain pressure in the fire protection water supply system and meet the guidelines. Therefore, we find that the use of a fire service jockey pump without a hydro-pneumatic tank is acceptable.

In our SER we also stated that the water supply for fire protection is taken from two 265,000-gallon water storage tanks and found the size of these tanks to be an acceptable deviation from the guidelines of Section C.6.b(11) of BTP CMEB 9.5-1 which requires a minimum capacity of 300,000 gallons per tank. In fact, each tank has a working capacity of 241,000 gallons. This capacity is sufficient to supply the greatest sprinkler or deluge system demand of 1400 gpm plus 500 gpm for hose streams for two hours with a margin of 13,000 gallons. In addition, the tanks are filled automatically by the shallow well makeup pump at a rate of 800 gpm when the water level falls 2 feet below the overflow level. Based on the available water capacity and the automatic makeup, we find the existing tanks to be an acceptable deviation from the guidelines of Section C.6.b(11) of BTP CMEB 9.5.1.

C. Sprinkler and Stand Pipe Systems

In our SER we stated that manual hose stations are located throughout the plant in accordance with NFPA 14, "Standard for the Installation of Standpipe and Hose Systems," and that, with the exception of the electrical tunnel, all areas of the plant can be reached with an effective hose stream with a maximum of 75 feet of hose. In the electrical tunnel, we concluded that the applicant demonstrated that adequate flow and pressure is available from the water supply system if 150 feet of hose is used. By letters dated May 17, 1985, and July 26, 1985, the applicant identified seven additional areas where 150 feet of hose is used.

The plant water distribution system is capable of supplying hose streams in these areas with adequate quantity of water and pressure through 150 feet of hose. In addition, sufficient space is available in each of the areas for accessibility and to ensure that the fire hose can be used in close proximity to the hose station.

Based on the above evaluation, we conclude that the use of 150 feet of fire hose in the electrical tunnel and the seven areas identified in the applicant's May 17, 1985 letter is an acceptable deviation from Section C.6.c of BTP CMEB 9.5-1.

VII. Fire Protection for Specific Plant Areas

D. Switchgear Rooms

During our site audit we observed that curbs were not installed to prevent water from flowing between the Division 1 and Division 2 switchgear rooms. By letter dated June 28, 1985, the applicant informed us that curbs have been installed between Fire Areas C-14 and C-15 to prevent water flow between the Control Building switchgear rooms. We find this acceptable.

XIII. Summary of Deviations from BTP CMEB 9.5-1

The following deviations from the guidelines of BTP CMEB 9.5-1 have been identified and are as follows:

1. Sealing Inside Conduits (Section V.A)
2. Steel Plate Enclosed Combustible Radiation Shielding (Section V.A)
3. Non-labeled Fire Doors (Section V.A)
4. Lack of Area-wide Fire Suppression Systems (Section V.B)
5. Use of Water Curtains to Separate Fire Areas (Section V.B)
6. Fire Water Supply Tank Size (Section VI.B)
7. Fire Hose Stations With 150 Feet of Hose (Section VI.C)
8. Carpet in the Control Room (Section VII.E)

Based on our evaluation, we find that the applicant's fire protection program with approved deviations is in conformance with the guidelines of BTP CMEB 9.5-1, Sections III.G, III.J and III.O of Appendix R to 10 CFR 50, and GDC 3 and is, therefore, acceptable.

Attachment 2

River Bend Station Unit 1
Fire Protection License Condition

1. The licensee shall implement and maintain in effort all provisions of the approved fire protection program as described in the Final Safety Analysis Report for the facility (or as described in submittals dated ----------) and as approved in the SER dated ---------(and Supplements dated ----------) subject to provisions 2, 3, 4, 5, and 6 below.

2. The licensee may make no change to the approved fire protection program which would significantly decrease the level of fire protection in the plant without prior approval of the Commission. To make such a change the licensee must submit an application for license amendment pursuant to 10 CFR 50.90.

3. The licensee may make changes to features of the approved fire protection program which do not significantly decrease the level of fire protection without prior Commission approval provided (a) such changes do not otherwise involve a change in a license condition or technical specification or result in an unreviewed safety question (see 10 CFR 50.59), and (b) such changes do not result in failure to complete the fire protection program approved by the Commission prior to license issuance. The licensee shall maintain, in an auditable form, a current record of all such changes, including an analysis of the effects of the change on the fire protection program, and shall make such records available to NRC inspectors upon request. All changes to the approved program shall be reported annually to the Director of the Office of Nuclear Reactor Regulation, along with the FSAR revisions required by 10 CFR 50.71(e).

4. Prior to exceeding five percent of rated power. Gulf States Utilities Company shall complete the fire wrapping of electrical raceways in the Control Building.

5. Prior to exceeding five percent of rated power, Gulf States Utilities Company shall complete the fire wrapping of electrical raceways in the Fuel Building.

6. Prior to exceeding five percent of rated power, Gulf States Utilities Company shall complete all modifications required to provide a means to safely shutdown the plant, in the event of a fire in the main control room, from outside of the control room, including revision of the plant procedures and re-training of the operators.

13 CONDUCT OF OPERATIONS

13.5 Station Administrative Procedures

13.5.2 Operating, Maintenance, and Other Procedures

13.5.2.2 Operating and Maintenance Procedures Program

In Section 13.5.2.2 of SER, the staff described the review and approval of the applicant's operating and maintenance procedures program through FSAR Amendment 11. The applicant transmitted FSAR Amendments 16 and 20, which included the applicant's changes to FSAR Section 13.5, "Procedures." The staff reviewed these changes and determined that the applicant's operating and maintenance procedures program continues to meet the relevant requirements of 10 CFR 50.34, and remains consistent with Regulatory Guide (RG) 1.33, ANSI N18.7-1976/ANS 3.2, and SRP Section 13.5.2, "Operating and Maintenance Procedures."

13.5.2.3 Reanalysis of Transients and Accidents; Development of Emergency Operating Procedures

Section 13.5.2.3 of the SER described the staff's review of the Procedures Generation Package (PGP) and identified one item (indicated as Confirmatory Item 60 in Table 1.4 the SER) that had to be completed before the applicant's program for developing procedures could be approved. This item was the identification and justification of safety-significant differences between the River Bend plant-specific technical guidelines and the NRC-approved BWR Owners Group technical guidelines. These differences and justifications were provided in a letter from the applicant, dated January 15, 1985. Supplemental information was provided to the staff on February 11, 1985.

The staff's review consisted of evaluating the justification for each deviation from the generic technical guidelines using plant-specific procedures, supplemented with several telephone discussions with the applicant.

The procedures submitted by the applicant have several plant-specific setpoints, operator action levels, and procedure references which are to be determined. During the routine prelicensing inspection program and before fuel load, the staff will confirm that the information required to complete each procedure is incorporated into the procedure.

Justifications for several deviations included commitments by the applicant to change plant procedures based on, in most cases, improvements identified during the plant's procedure verification and validation effort. These procedure changes were identified in deviations discussed on pages 7, 10, 16, 17, 19, 20, 27, 35, 39, and 52 of Attachment 1 to the applicant's January 15, 1985 letter. In letters dated April 17, May 15, and July 15, 1985, the applicant satisfactorily identified and justified these changes to its plant procedures. The applicant is expected to incorporate the technical content of these letters in

its emergency operating procedures (EOPs) and background documents in accordance with its EOP program. In addition, the applicant committed in its April 17, 1985, letter to change or clarify the deviations on pages 18, 34, and 50. The staff has confirmed the acceptability of these revised deviations.

The staff identified three errors associated with the deviations reviewed. First, although the justification on page 1 of Attachment 1 stated that generic emergency procedures guidelines (EPG) Cautions 1-8 were addressed in training and not contained in the procedures, two cautions which the operators would be expected to have difficulty remembering (6 and 8) are, in fact, included in the procedures. The applicant acknowledged this error and the staff found the exclusion of cautions 1-5 and 7 acceptable. Second, there is an inconsistency in the value used for the "maximum subcritical banked withdrawal position." The applicant stated that it had identified this inconsistency and had corrected it. The staff found this acceptable. Third, an apparent typographical error was identified in the justification for EOP-0002, step 3.4.4 (page 33 of Attachment 1) referencing 2 psig instead of 12 psig. An applicant representative stated that this error will be corrected. The staff found this acceptable.

Finally, the River Bend EOPs provide direction to the plant operators to vent the primary containment when containment pressure exceeds the "primary containment pressure limit" as defined by a curve of primary containment water level vs. suppression chamber pressure. The River Bend proposed limit is based on an ultimate capacity of 56 psia which is in excess of the design pressure by a factor of about 4. The NRC staff's Safety Evaluation Report on Revision 2 of the generic Emergency Procedure Guidelines (issued February 1983) has approved the use of twice design pressure as an interim limit, provided containment integrity can be demonstrated. The staff is aware of a proposed revision to the generic EPGs which will result in a redefinition of the venting criteria. In this regard, it is the staff's intent to continue the review of the proposed venting criterion (both generically and for each plant) which emphasis on the following areas:

(1) purge valve operability at the proposed venting pressure

(2) consideration of depressurization rate during venting to limit suppression pool flashing

(3) safety/relief valve actuation at high containment pressures

(4) structural analyses and tests

(5) limitation of offsite radioactive releases by selective use of vent paths

The staff must complete its review of this item before the plant can operate above 5% of rated power.

The staff concludes that Confirmatory Item 60 has been adequately addressed and, therefore, the applicant's program for developing EOPs is acceptable for fuel load and operation up to 5% of rated power.

During the staff's review of the applicant's EOP program, it was determined that the applicant is considering changing its method of presenting EOPs currently described in the PGP from narrative to flowchart. It is the staff's

position that a change in EOP presentation method from narrative to flowchart is quite a significant change and currently there are no acceptance criteria in SRP Section 13.5.2, "Operating and Maintenance Procedures" which address the development of flowchart procedures. Furthermore, the applicant has not submitted a plan for developing flowchart EOPs. The staff should review the applicant's method for developing, verifying/validating and implementing flowchart EOPs before their implementation.

14 INITIAL TEST PROGRAM

The Initial Plant Test Program of the River Bend Station Unit 1 was reviewed and approved through FSAR Amendment 10 and documented in the SER. Recently, the staff has completed its review of FSAR amendments through Amendment 18. Changes and modifications had been made to a previously approved test program which required additional information from the applicant before the staff could complete its review. The applicant responded with the necessary information in a letter dated May 15, 1985. The staff has reviewed the revised Initial Plant Test Program and finds it acceptable.

In the May 15, 1985, letter, the applicant took exception to the provision for 2-hour testing at 110% of rated load in Position C.2.a(3) of RG 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants." The acceptability for this exception and the applicant's proposed test program for the Transamerica Delaval diesel generators at River Bend is addressed separately in Section 8 of this supplement.

15 TRANSIENT AND ACCIDENT ANALYSIS

15.4 Reactivity and Power Distribution Anomalies

15.4.2 Rod Withdrawal Error at Power

In the SER, the staff stated that the statistical analysis of the rod withdrawal event at power may not be applied to cases with a control cell core loading or those loaded to accommodate a high-energy/high-discharge exposure cycle unless a compliance check is performed to demonstrate its applicability. Since the River Bend first-cycle loading is a control-cell core, the applicant has provided assurance that such a compliance check has been done (see letter from applicant dated June 19, 1985). Therefore, the staff concludes that the withdrawal limits resulting from the generic analysis are acceptable for River Bend.

15.4.7 Operation of a Fuel Assembly in an Improper Position--Fuel Misloading Event

In the SER, the staff reviewed the applicant's analysis of a three-bundle configuration. The applicant has modified the initial core with a control cell core containing five different enrichments.

For the revised core, the limiting fuel bundle loading error is that of interchanging a 2.78% enrichment bundle with a 0.94% enrichment bundle in the center of the core and away from a low-power-range-monitor (LPRM) string. When the mirror-image location (assumed to be instrumented) is placed on thermal limits, the misloaded bundle will exceed operating limits.

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Author's Name:
Stern/Sanders

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18 HUMAN FACTORS ENGINEERING

In the discussion that follows, the staff closed out the open licensing issues of the detailed control room design review (DCRDR) required by Supplement 1 to NUREG-0737. The Lawrence Livermore National Laboratory (LLNL) Technical Evaluation Report (TER) dated January 29, 1985 (see Appendix J of Supplement 2 to SER), and the LLNL Supplemental Technical Evaluation Report (STER) dated June 28, 1985 (see Appendix N of this supplement), provide the evaluation of the River Bend Station Unit 1 DCRDR up to and including the applicant's Supplemental Summary Report (SSR) No. 1 dated May 14, 1985. The staff reviewed the SSR No. 2 dated June 12, 1985, which resolved the concerns expressed in Appendix B of the enclosed LLNL STER, and discussed the resolutions with the LLNL staff. The NRC staff concurs in the technical evaluations and conclusions contained in the STER, which is appended to this supplement.

The DCRDR open issues which are identified in the conclusions section of SSER 2 are closed out based on the following acceptable responses provided by the applicant:

(1) confirmed the continued participation of human factors specialists in the remaining DCRDR activities

(2) submitted additional task analysis documentation results discussed in SSER 2 under "Function and Task Analyses"

(3) confirmed that the remaining control room survey items have been completed and the submittal of acceptable resolutions and implementation schedules for human engineering discrepancies (HEDs) have been identified

(4) provided acceptable responses to the specific concerns regarding resolution of the HEDs identified in Appendices A and B to the Technical Evaluation Report (January 29, 1985) appended to SSER 2 as Appendix J

(5) confirmed that all control room modifications resulting from the DCRDR have been verified to assure they have provided the expected corrections and do not introduce new HEDs

Although the applicant committed to implementing corrective actions for a number of HEDs before licensing, the staff does not plan to confirm that all of these actions have been completed before issuing the low-power license. However, the staff will confirm that all actions proposed to correct HEDs before licensing and before exceeding 5% of rated power have been completed before a full-power license is issued. All but 11 of approximately 325 HEDs will be corrected before exceeding 5% of rated power. The 11 HEDs will be corrected during the first refueling outage. The staff has determined that the confirmation of actions required to correct certain HEDs before licensing could be deferred until before issuance of a full-power license without affecting safe operation of the plant. The identification of all HEDs requiring corrective action and the applicant's accepted proposed schedules for implementing the

actions are contained in the River Bend DCRDR Summary Report dated October 31, 1984, in supplements dated May 14 and June 12, 1985, and in the applicant's letter of July 30, 1985.

On the basis of the staff's review of the River Bend Program Plan, DCRDR Summary Report, and supplements, and an onsite, in-progress audit, the staff has concluded that except for completing the implementation of corrective actions for certain HEDs, the applicant has satisfactorily completed its DCRDR for River Bend Station Unit 1 in accordance with the requirements of Supplement 1 to NUREG-0737. The staff will verify implementation of actions to correct certain HEDs before exceeding 5% of rated power and before startup after the first refueling outage, in accordance with commitments made in the Summary Report, in supplements dated October 31, 1984; May 14, 1985; and June 12, 1985; and in the applicant's letter of July 30, 1985.

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APPENDIX L

PRESERVICE INSPECTION RELIEF REQUEST EVALUATION

I. INTRODUCTION

This section was prepared with the technical assistance of Department of Energy (DOE) contractors from the Idaho National Engineering Laboratory.

For nuclear power facilities whose construction permit was issued on or after July 1, 1974, 10 CFR 50.55a(g)(3) specifies that components shall meet the preservice inspection (PSI) requirements set forth in editions and addenda of Section XI of the ASME Boiler and Pressure Vessel Code applied to the construction of the particular component. The provisions of 10 CFR 50.55a(g)(3) also state that components (including supports) may meet the requirements set forth in subsequent editions and addenda of this Code which are incorporated by reference in 10 CFR 50.55a(b) subject to the limitations and modifications listed therein.

In the River Bend Station PSI Program, Revision 3, submitted on May 15, 1985 and in letters dated June 10 and June 24, 1985, the applicant requested relief from ASME Section XI Code requirements which the applicant has determined to be not practical and provided a technical justification. Therefore, the staff evaluation consisted of comparing the applicant's submittals to the requirements of the applicable Code edition and addenda and determining if relief from the Code requirements was justified.

II. TECHNICAL REVIEW CONSIDERATIONS

A. The construction permit for River Bend Station was issued on March 25, 1977 and components (including supports), which are classified as ASME Code Class 1 and 2, have been designed and provided with access to enable the performance of required preservice examinations set forth in the 1977 Edition of the ASME Boiler and Pressure Vessel Code, Section XI, including the Addenda through Summer 1978.

B. Verification of as-built structural integrity of the primary pressure boundary is not dependent on the Section XI preservice examination. The applicable construction codes to which the primary pressure boundary was fabricated contain examination and testing requirements which by themselves provide the necessary assurance that the pressure boundary components are capable of performing safely under all operating conditions reviewed in the FSAR and described in the plant design specification. As a part of these examinations, all of the primary pressure boundary, full-penetration welds were volumetrically examined (radiographed) and the system was subjected to hydrostatic pressure tests.

C. The intent of a preservice examination is to establish a reference or baseline prior to the initial operation of the facility. The results of

subsequent inservice examination can then be compared with the original condition to determine whether changes have occurred. If the inservice inspection results show no change from the original condition, no action is required. In the case where baseline data are not available, all flaws must be treated as new flaws and evaluated accordingly. Section XI of the ASME Code contains acceptance standards which may be used as the basis for evaluating the acceptability of such flaws.

D. Other benefits of the preservice examination include providing redundant or alternative volumetric examination of the primary pressure boundary using a test method different from that employed during the component fabrication. Successful performance of preservice examination also demonstrates that the welds so examined are capable of subsequent inservice examination using a similar test method.

In the case of River Bend Station, a large portion of the preservice examination required by the ASME Code was performed. Failure to perform a 100% preservice examination of the welds identified below will not significantly affect the assurance of the initial structural integrity.

E. In some instances where the required preservice examinations were not performed to the full extent specified by the applicable ASME Code, the staff may require that these examinations or supplemental examinations be conducted as a part of the inservice inspection program. Requiring supplemental examinations to be performed at this time would result in hardships or unusual difficulties without a compensating increase in the level of quality or safety. The performance of supplemental examinations, such as surface examinations in areas where volumetric examination is difficult, will be more meaningful after a period of operation. Acceptable preoperational integrity has already been established by similar ASME Code Section III fabrication examinations.

In cases where parts of the required examination areas cannot be effectively examined because of a combination of component design or current examination technique limitations, the development of new or improved examination techniques will continue to be evaluated. As improvements in these areas are achieved, the staff will require that these new techniques be made a part of the inservice examination requirements for the components or welds which received a limited preservice examination. Several of the preservice inspection relief requests involve limitations to the examination of the required volume of a specific weld. The inservice inspection (ISI) program is based on the examination of a representative sample of welds to detect generic degradation. In the event that the welds identified in the PSI relief requests are required to be examined again, the possibility of augmented inservice inspection will be evaluated during review of the Applicant's initial 10-year ISI program. An augmented program may include increasing the extent and/or frequency of examination of accessible welds.

III. EVALUATION OF RELIEF REQUESTS

The applicant requested relief from specific preservice inspection requirements in Revision 3 of the River Bend Station PSI Program submitted May 15, 1985, and submitted revisions to these relief requests in letters dated June 10 and June 24,

1985. Based on the information submitted by the applicant and the staff's review of the design, geometry, and materials of construction of the components, certain preservice requirements of the ASME Boiler and Pressure Vessel Code, Section XI have been determined to be impractical to perform. The applicant has demonstrated that either (i) the proposed alternatives would provide an acceptable level of quality and safety or (ii) compliance with the specified requirements of this section would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, pursuant to 10 CFR 50.55a(a)(3), conclusions that these preservice requirements are impractical are justified as follows. Unless otherwise stated, references to the Code refer to the ASME Code, Section XI, 1977 Edition, including addenda through Summer 1978.

A. Relief Request R0001, Examination Category B-J, Pressure-Retaining Piping Welds (21 Welds)

Code Requirement: ASME Code Class 1, pressure-retaining piping welds are required to receive a 100% surface and volumetric examination for PSI in accordance with IWB-2500-1, Examination Category B-J, Item B9.10.

Code Relief Request: Relief is requested from performing the Code-required volumetric examination on the pressure-retaining welds listed below:

System & Weld Number	Type of Weld
ICS-006-057-1	
057BFW004	Pipe to flange
MSS-024-600-1	
600A2SW05E	Sweep-o-let to flange
600A2SW05D	Sweep-o-let to flange
MSS-024-700-1	
700A2SW08M	Sweep-o-let to flange
700A2SW08L	Sweep-o-let to flange
700A1SW08K	Sweep-o-let to flange
700A2SW08J	Sweep-o-let to flange
700A2SW08H	Sweep-o-let to flange
MSS-024-800-1	
800A2SW07K	Sweep-o-let to flange
800A2SW07J	Sweep-o-let to flange
800A2SW07M	Sweep-o-let to flange
800A2SW07L	Sweep-o-let to flange
800A2SW07N	Sweep-o-let to flange
800A2SW07P	Sweep-o-let to flange
MSS-024-900-1	
900A2SW06F	Sweep-o-let to flange
900A2SW06G	Sweep-o-let to flange
900A2SW06H	Sweep-o-let to flange
1B13*D020	
1-ICS-014A-SW001	Tee to flange
1-ICS-014A-SW002	Tee to flange
1-ICS-014A-SW003	Tee to flange
1-ICS-014A-SW004	Tee to flange

Reason for Request: Because of the configuration (pipe to flange, sweep-o-let to flange, or tee to flange), there is not sufficient area to perform a meaningful ultrasonic examination. Sketches showing the typical configuration of each weld were provided in the PSI Program.

Staff Evaluation: The staff has reviewed the geometric configuration of the subject welds and determined that the required preservice volumetric inspection, using ultrasonic techniques, is not practical because of the design of the component. This relief request is acceptable for PSI based on the following considerations:

(1) Other welds in the same piping runs received full Code examinations. The overall integrity of the pressure boundary thus was verified by sampling.

(2) These welds have been subject to a system hydrostatic test and found acceptable in accordance with ASME Code Section III, Class 1, requirements.

(3) These welds have been volumetrically examined by radiography, and found acceptable in accordance with ASME Code Section III, Class 1, requirements.

(4) These welds have also been surface examined by magnetic particle, and found acceptable in accordance with ASME Code Section XI, Class 1, requirements.

The above examinations and tests are an acceptable alternative for PSI and provide reasonable assurance of the preservice structural integrity of the subject welds. The staff has determined that compliance with the specified requirements would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety because the components would have to be removed and redesigned to provide an inspectable weld surface for ultrasonic inspection.

B. Relief Request R0002, Examination Category B-J, Pressure-Retaining Piping Welds (6 welds)

Code Requirement: ASME Code Class 1, pressure-retaining piping welds are required to receive a 100% surface and volumetric examination for PSI in accordance with IWB-2500-1, Examination Category B-J, Item B9.10.

Code Relief Request: Relief is requested from performing 100% of the Code-required volumetric examination on the pressure-retaining welds listed below:

Standby Liquid Control Welds	Approximate % Examined
1-SLS-042B-FW016	70
1-SLS-042B-FW009	60
1-SLS-037C-FW004	65

Reactor Core Isolation Cooling System Welds	Approximate % Examined
1-ICS-001B-SW010	75

Main Steam Piping Sweep-O-Let Welds	Approximate % Examined
1-MSS-600A2-SW05D	75
1-MSS-900A2-SW06E	75

Reason for Request: Because of the location and configuration of adjacent component supports or welded pads located on weld metal repair, the required volumetric examination cannot be performed on 100% of the required weld volume. Sketches showing typical restrictions from adjacent structures were provided in the PSI Program. The staff has reviewed the design configuration of the adjacent structures and determined that the preservice inspection, to the extent required by the Code, is impractical.

Staff Evaluation: This relief request is acceptable for PSI based on the following considerations:

(1) Other similar welds in the same piping runs received full Code examinations. Thus, the overall integrity of the pressure boundary was verified by sampling.

(2) These welds were volumetrically examined by radiography and found acceptable in accordance with ASME Code Section III, Class 1, requirements.

(3) These welds were subject to a system hydrostatic test and found acceptable in accordance with ASME Code Section III requirements.

(4) The above welds have received the Code-required surface examination and the accessible portions of the above welds have received a preservice volumetric examination in accordance with ASME Code Section XI.

Therefore, the staff concludes that the limited Section XI volumetric examination, the required Section XI surface examination, and the Section III fabrication examinations performed during construction are an acceptable alternative for PSI and provide reasonable assurance of the preservice structural integrity of the subject welds.

C. Relief Request R003, Examination Category C-G, Pressure-Retaining Welds in Pumps

Code Requirement: ASME Code Class 2, pressure-retaining welds in pumps are required to receive a surface examination for PSI in accordance with ASME Code Section XI, IWC-2500-1, Examination Category C-G, Item C6.10.

Code Relief Request: Relief is requested from performing a preservice surface examination on those portions of welds located within the concrete pump support encasement on the following pumps.

Pump	Pump No.
Low Pressure Core Spray	IE21 PC001
High Pressure Core Spray	1E22 PC001
RHS "B"	IE12 PC002-A

Reason for Request: These welds are located in the pump housing and are encased in concrete. Examination of required welds would require complete disassembly of the pumps. Examination of the accessible pump casing welds were performed. If a pump is disassembled for normal maintenance, examination of the welds will be considered at that time. Sketches showing the installed configuration of the pumps were provided in the PSI Program.

Staff Evaluation: The staff has determined that disassembly of the pumps would be necessary to perform the required examination in the installed configuration. This relief request is acceptable based on the following considerations:

(1) These welds have been volumetrically examined by radiography, and found acceptable in accordance with the ASME Code Section III, Class 2, requirements.

(2) These pumps were subject to a system hydrostatic test and found acceptable in accordance with ASME Code Section III, Class 2, requirements.

(3) The failure of these welds, thus leading to failure of the pump, would have no adverse affect on plant safety because redundant emergency core cooling systems are provided.

The staff concludes that requiring a surface examination of the welds encased in concrete would result in hardships or unusual difficulties without a significant increase in the level of quality and safety because the radiography performed during fabrication and the hydrostatic test are equivalent or superior to the required preservice inspection. In the event that these pumps are disassembled for inservice repair or maintenance, so that the subject welds are accessible, the staff will require that the preservice inspection be performed at that time.

D. Relief Request R004, Examination Category B-O, Peripheral Control Rod Drive Housing Welds, and Examination Category B-G-2, Bolting Located on CRD Housings and Incore Housings

Code Requirement:

(1) Peripheral control rod drive housing welds are required to be surface examined (liquid penetrant) for PSI in accordance with ASME Code Section XI, IWB-2500-1, Examination Category B-O.

(2) Pressure-retaining bolting for the flange-to-flange joints, located on the control rod drive (CRD) and incore housings, are required to receive a visual examination (VT-1) for PSI in accordance with ASME Code Section XI, IWB-2500-1, Examination Category B-G-2.

Code Relief Request: Relief is requested from performing the liquid penetrant examinations on the peripheral CRD housing welds and the visual (VT-1) examinations on the subject bolting.

Reason for Request: The weld area and bolting is not accessible for examination unless the CRD support structure is removed. A total 360° surface examination cannot be accomplished because of interference from adjacent CRD housings. Examination of the weld from the inside of the CRD housing would require that the CRD mechanisms be removed, which could result in damage to the drive.

Staff Evaluation: This relief request is acceptable for preservice inspection for the following considerations:

(1) The peripheral CRD housing welds have been volumetrically and surface examined by radiographic and liquid penetrant methods, and have been hydrostatic tested in accordance with the requirements of ASME Code Section III.

(2) All incore and CRD housing bolting has been examined in accordance with the requirements of ASME Code Section III.

(3) The welds and bolting were subject to hydrostatic testing and found acceptable in accordance with the requirements of ASME Code Section III.

The staff concludes that requiring the removal of the installed CRD support structure to perform the required surface and visual examinations would result in hardships and unusual difficulties without a compensating increase in the level of quality and safety because the radiography performed during fabrication and the hydrostatic test are equivalent or superior to the required perservice inspection. In the event that the CRD housings are disassembled for inservice repair or maintenance, so that the subject welds and bolting are accessible, the staff will require that the perservice inspection be performed at that time.

E. Relief Request R005, Examination Category B-K-1, Integral Welded Attachments for Class 1 Piping, Pumps, and Valves, and Examination Category C-C, Integral Welded Attachments for Class 2 Piping, Pumps, and Valves

(Relief Request R005 has been withdrawn by the applicant.)

F. Relief Request R006, Examination Category B-J, Pressure-Retaining Dissimilar Metal Piping Welds

Code Requirement: ASME Code Class 1, pressure-retaining dissimilar metal welds are required to receive a 100% surface and volumetric examination for PSI in accordance with ASME Code Section XI, IWB-2500-1, Examination Category B-J, Note (1)(c), Item B9.11.

Code Relief Request: Relief is requested from performing 100% of the Code-required volumetric examination on the following welds:

Line Number	Weld Number
1-RCS-020-900-A	900A-FWB25
1-RCS-020-800-A	800A-FWA24
1-RHS-018-900-A	900A-FWB22

Reason for Request: Because of the configuration of these welds (fitting to pipe), a meaningful ultrasonic examination can only be performed from one side of the weld. Sketches showing the typical configuration of each weld were provided in the PSI Program.

Staff Evaluation: The staff has reviewed the design configuration of the subject welds and determined that the preservice inspection to the extent required by the Code is impractical. This relief request is acceptable for preservice inspection based on the following considerations:

(1) These welds have been volumetrically examined by radiography and found acceptable in accordance with ASME Code Section III, Class 1, requirements.

(2) These welds were subject to a system hydrostatic pressure test and found acceptable in accordance with ASME Code Section III, Class 1, requirements.

(3) These welds have been surface examined by liquid penetrant and found acceptable in accordance with ASME Code Section XI, Class 1, requirements.

The staff has therefore concluded the limited Section XI volumetric examination, the required Section XI surface examination, and the fabrication examinations performed during construction are acceptable alternatives for PSI and provide reasonable assurance of the preservice structural integrity of the subject welds.

G. Relief Request R007, Examination Category B-J, Pressure-Retaining Piping Longitudinal Welds

Code Requirement: ASME Code Class 1, longitudinal welds on 4-inch and greater NPS piping are required to receive a 100% surface and volumetric examination for PSI in accordance with ASME Code Section XI, IWB-2500-1, Examination Category B-J, Item B9.12 and Paragraph IWB-2200(a).

Code Relief Request: Relief is requested from performing 100% of the Code-required examination on the following welds:

System & Line	Weld Number
1-MSS-024-600-1	600A2SW05BL1
	600A2SW05BL2
1-MSS-024-900-1	900A2SW06BL1
	900A2SW06BL2
1-MSS-024-700-1	700A2SW08BL1
	700A2SW08BL2
1-MSS-024-800-1	800A2SW07BL1
	800A2SW07BL2
1-RCS-010-80G-1	800C-FWA16L
1-RCS-010-80D-1	800C-FWA13L
1-RCS-010-80E-1	800C-FWA14L
1-RCS-010-90D-1	900C-FWB13L
1-RCS-020-900-1	900A-SW004BCL
1-RCS-020-900-1	900A-SW004BBL2
1-RCS-020-80A-1	800B-FWA06L
1-RCS-020-800-1	800A-SW002ABL
1-RCS-020-900-1	900A-SW002BBL
1-RCS-010-80F-1	800C-FWA15L
1-RCS-010-90E-1	900C-FWB14L
1-RCS-010-90C-1	900C-FWB12L
1-RCS-010-90F-1	900C-FWB15L
1-RCS-010-90G-1	900C-FWB16L
1-RCS-010-80C-1	800C-FWA12L
1-RCS-020-80A-1	800B-SW007ABL
1-RCS-020-800-1	800A-FWA04L

Reason for Request: The required area of examination cannot be examined because of the location of integral attachments, branch connections, and Code identification plates. The location of the specific obstruction for each weld was identified. The accessible portion of these longitudinal welds will be examined in accordance with Section XI requirements.

Staff Evaluation: This relief request is acceptable for preservice inspection based on the following considerations:

(1) The accessible portions of the above-listed welds received a preservice volumetric and surface examination in accordance with the ASME Code Section XI.

(2) Adjacent weld lengths in the same piping runs received full Code examination. The overall integrity of the pressure boundary thus was verified by sampling.

(3) These welds have been volumetrically examined by radiography and found acceptable in accordance with ASME Code Section III requirements.

(4) The subject piping welds received a system hydrostatic test and were found acceptable in accordance with ASME Code Section III requirements.

The staff has determined that the Code preservice examination was essentially completed on the majority of welds. The staff concludes that the limited Section XI volumetric examinations, the required surface examinations, and the fabrication examinations performed during construction are acceptable alternatives for PSI and provide reasonable assurance of the preservice structural integrity of the subject welds.

H. Relief Request R0008, Examination Category B-J, Pressure-Retaining Welds in Piping

Code Requirement: ASME Code Class 1, pressure-retaining piping welds are required to receive a 100% surface and volumetric examination for PSI in accordance with IWB-2500-1, Examination Category B-J, Item B9.10.

Code Relief Request: Relief is requested from performing 100% of the Code-required volumetric examination on the fitting side of the following pipe to fitting or component welds:

System & Line	Weld	Weld Configurations
1-RCS-010-80C-1	800C-FWA12	Pipe to sweep-o-let
80D-1	800C-FWA13	Pipe to sweep-o-let
80F-1	800C-FWA15	Pipe to sweep-o-let
80G-1	800C-FWA16	Pipe to sweep-o-let
1-RCS-020-80A-1	800C-FWA11	Pipe to tee
80A-1	800B-FWA10	Pipe to valve
90A-1	900CX-SW014CA	Reducer to tee
90A-1	900C-FWB11	Pipe to tee

System & Line	Weld	Weld Configurations
1-RCS-010-90F-1	900C-FWB15	Pipe to sweep-o-let
90G-1	900C-FWB16	Pipe to sweep-o-let
90D-1	900C-FWB13	Pipe to sweep-o-let
90C-1	900C-FWB12	Pipe to sweep-o-let
1-RCS-020-900-1	900A-SW004BA	Pipe to tee
900-1	900A-SW004BC	Pipe to tee
900-1	900A-FWB03	Pipe to pump
800-1	800A-FWA05	Pipe to pump
800-1	800A-FWA03	Pipe to valve
900-1	900A-SW005BA	Pipe to elbow
900-1	900A-FWB04	Pipe to valve
800-1	800A-SW005AA	Pipe to elbow
800-1	800A-FWA04	Pipe to valve
1-RCS-010-90G-1	900C-FWB21	Pipe to nozzle
90F-1	900C-FWB20	Pipe to nozzle
90E-1	900C-FWB19	Pipe to nozzle
90D-1	900C-FWB18	Pipe to nozzle
90C-1	900C-FWB17	Pipe to nozzle
80C-1	800C-FWA17	Pipe to nozzle
80D-1	800C-FWA18	Pipe to nozzle
80E-1	800C-FWA19	Pipe to nozzle
80F-1	800C-FWA20	Pipe to nozzle
80G-1	800C-FWA21	Pipe to nozzle

Reason for Request: Because of the configuration of these welds, the ultrasonic examination can only be performed from one side of the weld using a 1-1/2 V technique. Sketches showing the typical configuration of each weld were provided in the PSI Program.

Staff Evaluation: The staff has reviewed the geometric configuration of the subject welds and determined that the required preservice volumetric inspection, using ultrasonic techniques, is not practical from the fitting side because of the design of the component. This relief request is acceptable for preservice inspection based on the following considerations:

(1) These welds have been volumetrically examined by radiography, and found acceptable in accordance with ASME Code Section III, Class 1, requirements.

(2) These welds have also received a liquid penetrant surface examination and were found acceptable in accordance with ASME Code Section XI, Class 1, requirements.

(3) These welds were subject to a system hydrostatic test and found acceptable in accordance with ASME Code Section III requirements.

(4) The staff will continue to evaluate the development of new or improved procedures and will require that these improved procedures be made part of the inservice examination requirements.

The staff has determined that the limited Section XI examinations from the pipe side of the weld, the required surface examinations, and the fabrication examinations performed during construction are acceptable alternatives for PSI as they provide reasonable assurance of the preservice structural integrity of the subject welds.

I. Relief Request R0009, Examination Categories B-L-2 and B-M-2, Pump Casings and Valve Bodies

Code Requirement: Class 1 pump casing internals and valve body internal surfaces are required to receive a visual examination (VT-1) for PSI in accordance with ASME Code Section XI, IWB-2500-1, B-L-2 Item B12.20 and B-M-2 Item B12.40.

Code Relief Request: Relief is requested from performing the required examination for PSI.

Reason for Request: Visual examination of the internals of the pumps and valves at this time would require disassembly, which would impose an undue hardship on the plant and may increase the probability of pump failure.

Staff Evaluation: This relief request is acceptable for PSI based on the following:

The subject pump casings and valve bodies were volumetrically examined by radiography and hydrostatically tested in accordance with ASME Code Section III requirements. Disassembly of pumps and valves at this time, for the sole purpose of performing preservice visual examination, would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. The staff has concluded that these construction code examinations and tests exceed the requirements for visual examination and therefore, are an acceptable alternative to the Section XI preservice visual examination.

J. Relief Request R0010, Examination Category B-J, Pressure-Retaining Piping Weld (1 weld)

(Relief Request R0010 has been withdrawn by the applicant.)

K. Relief Request R0011, Examination Category C-B, Pressure-Retaining Nozzle Welds in Vessels

Code Requirement: Table IWC-2500-1, Examination Category C-B, Item C2.20, requires surface and volumetric examination of the regions described in Figure IWC-2500-4 for nozzles in vessels over 1/2-inch nominal thickness. Figure IWC-2500-4 requires volumetric examination of the inner radii on nozzles over 12-inch nominal pipe size.

Code Relief Request: Relief is requested from performing the Code-required volumetric examination on the nozzle inner radii for the following residual heat removal (RHR) heat exchanger nozzles:

Component Description	Nozzle Number
1-RHS-1-E12*EB 001-A	N3
1-RHS-1-E12*EB 001-A	N4

Reason for Request: The nozzles contain inherent geometric constraints which limit the ability to perform meaningful ultrasonic examination of the nozzles' inner radii. To perform an alternate surface examination, the tube bundle would have to be removed from the heat exchanger. However, a surface examination will be performed if the heat exchanger is disassembled. Sketches of the nozzle configuration are provided in the PSI Program.

Staff Evaluation: The staff review of the design configuration of the nozzle inner radius has concluded that the Code-required volumetric examination is impractical and would require redesign of the nozzle. This relief request is acceptable for PSI based on the following considerations:

(1) The subject weld area received radiographic examination and a hydrostatic test during fabrication in accordance with ASME Code Section III requirements.

(2) An ultrasonic examination has been performed on the nozzle-to-vessel welds per ASME Code Section XI requirements.

(3) The staff will continue to evaluate the development of new or improved procedures and will require that the procedures be made part of the ISI examination requirements.

(4) If the heat exchanger is disassembled, the applicant has committed to perform an alternative surface examination.

The staff concludes that compliance with the Code requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety and the Section III hydrostatic test provides a reasonable assurance of an acceptable level of structural integrity of the nozzle inner radii region.

IV. CONCLUSIONS

Based on the foregoing, pursuant to 10 CFR 50.55a(a)(3), the staff has determined that certain Section XI required preservice examinations are impractical. The applicant has demonstrated that either (i) the proposed alternatives would provide an acceptable level of quality and safety or (ii) compliance with the requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety.

The staff technical evaluation has not identified any practical method by which the existing River Bend Station can meet all the specific preservice inspection requirements of Section XI of the ASME Code. Requiring compliance with all the exact Section XI-required examinations would delay the startup of the plant in order to redesign a significant number of plant systems, obtain sufficient replacement components, install the new components, and repeat the preservice examination of these components. Examples of components that would require redesign to meet the specific preservice examination provisions are the core spray pumps and a significant number of the piping and component support systems. Even after the redesign efforts, complete compliance with the preservice examination requirements probably could not be achieved. However, the as-built structural integrity of the existing primary pressure boundary has already been established by the construction code fabrication examinations.

Based on the staff's review and evaluation, it is concluded that the public interest is not served by imposing certain provisions of Section XI of the ASME Code that have been determined to be impractical. Pursuant to 10 CFR 50.55a(a)(3), relief is allowed from these requirements which are impractical to implement.

The applicant has provided information addressing compliance with this requirement of 10 CFR 50.49.

The applicant stated that equipment requiring qualification under 10 CFR 50.49(b)(1) includes all safety-related equipment required to perform its safety function in a harsh environment. Also included is equipment in any directly mechanically connected auxiliary systems with electrical components (e.g., cooling water or lubricating systems) which support the safety function of other safety-related equipment.

The systems identified by the applicant for the environmental qualification program as being required to function to mitigate the consequences of loss-of-coolant accidents (LOCAs) or high-energy line breaks (HELBs) that have components located in a harsh environment were compared to FSAR Table 3.2-1, "Equipment and Structure Classification." The omission of systems from the harsh environment program was adequately justified by the applicant. Table 3.11.1 lists the systems identified.

To demonstrate compliance with 10 CFR 50.49(b)(2), the applicant stated that equipment requiring qualification under 10 CFR 50.49(b)(2) includes all equipment electrically connected directly into the control or power circuitry of the safety-related equipment whose failure under postulated environmental conditions could adversely affect the safety function of other equipment. The identification of this equipment utilized, among other measures, review of applicable elementary wiring diagrams.

The staff referred to the information provided by the applicant to meet the requirements of Regulatory Guide 1.75, "Physical Independence of Electric Systems," wherein the applicant provided alternate methods of meeting those requirements. The alternate methods have been reviewed and found acceptable by the staff. Refer to NUREG 0989 Sections 8.4.5 and 8.4.6 dated May 5, 1984 and to Sections 8.4.5 and 8.4.6 of this report for details. In addition, the staff reviewed and found acceptable, the applicant's response to concerns identified in IE information notice 79-22 "Qualification of Control Systems." Accordingly, the staff concludes that the applicant's conformance to 10 CFR 50.49(b)(2) is acceptable.

Steve needs to verify

10 CFR 50.49(b)(3) requires that all installed RG 1.97, Category 1 and 2 instrumentation located in a harsh environment be included in the equipment qualification program unless adequate justification is provided. The applicant has indicated a commitment to comply with the requirements of 10 CFR 50.49(b)(3); however, in addressing conformance with RG 1.97, the applicant has identified a number of exceptions. The staff will determine the acceptability of these exceptions as part of its review for conformance with RG 1.97. ~~This review may result in the addition of equipment to the environmental qualification program.~~

3.11.3.2 Qualification Methods

3.11.3.2.1 Electrical Equipment in a Harsh Environment

Detailed procedures for qualifying safety-related electrical equipment in a harsh environment are defined in NUREG-0588. The criteria in this NUREG are also applicable to the other equipment important to safety defined in 10 CFR 50.49.

The General Electric (GE) Environmental Qualification Program presented in GE Topical Report NEDE-24326-1-P outlines the methodology used by GE to qualify nuclear steam supply system (NSSS) safety-related electrical equipment subject to a harsh environment. The applicant, in RBS environmental qualification document (EQD), dated May 1984, adopted this GE program for River Bend Station. Based on the results of its review of the GE program, the staff found that the GE position on time margin, as presented in Topical Report NEDE-24326-1-P, did not address the requirement of NUREG-0588, which requires that time margin be a minimum of one hour. The staff identified this as an issue to be addressed by each applicant, and requires that time margin be approached in accordance with NUREG-0588, or as amplified in Regulatory Guide 1.89. The applicant has approached time margin in essentially the same manner as that specified in Regulatory Guide 1.89. The staff has reviewed the applicant's qualification methodology and finds it acceptable to meet the requirements of NUREG-0588 Category 1.

3.11.3.2.2 Safety-Related Mechanical Equipment in a Harsh Environment

Although there are no detailed requirements for mechanical equipment, GDC 1, "Quality Standards and Records," and 4, "Environmental and Missile Design Bases," and Appendix B to 10 CFR 50, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants" (Section III, "Design Control," and XVII, "Quality Assurance Records"), contain the following requirements related to equipment qualifications:

- Components shall be designed to be compatible with the postulated environmental conditions, including those associated with LOCAs.

- Measures shall be established for the selection and review for suitability of application of materials, parts, and equipment that are essential to safety-related functions.

- Design control measures shall be established for verifying the adequacy of design.

- Equipment qualification records shall be maintained and shall include the results of tests and materials analyses.

The results of the safety-related mechanical equipment qualification program have been submitted to the staff for review. In addition, qualification documentation for three items of safety-related mechanical equipment has been submitted by the applicant and has been reviewed by the staff. The staff review has verified that the requirements for environmental qualification of safety-related mechanical equipment have been adequately addressed.

3.11.3.3 Service Conditions

NUREG-0588 defines the methods to be utilized for determining the environmental conditions associated with LOCAs or HELBs, inside or outside of containment. The review and evaluation of the adequacy of these environmental conditions are described below. The staff has reviewed the qualification documentation to

RPY — HELB - High Energy Line Break

ensure that the qualification conditions enveloped the environmental conditions established by the applicant.

3.11.3.3.1 Temperature, Pressure, and Humidity Conditions Inside the Drywell

The applicant provided the LOCA/main steamline break (MSLB) profiles used for equipment qualification program submittals. The peak values in the drywell shown on these profiles are as follows:

	Maximum temperature, °F	Maximum pressure, psig	Humidity, %
LOCA/MSLB	330	25	100

The staff has reviewed these profiles and finds them acceptable for use in equipment qualification; that is, there is reasonable assurance that the actual pressures and temperatures will not exceed these profiles anywhere within the specified environmental zone (except in the break zone).

3.11.3.3.2 Temperature, Pressure, and Humidity Conditions Outside the Drywell

The applicant has provided the temperature, pressure, and humidity conditions associated with HELBs outside the drywell. The criteria used to define the location of HELBs are described in FSAR Section 3.6.

The staff has used a screening criterion of saturation temperature at the calculated pressure to verify that the peak temperatures identified by the applicant are acceptable.

3.11.3.3.3 Submergence

Flood levels for various areas have been calculated, with the flood level in the drywell being 109' following a LOCA. The effects of flooding on equipment have been evaluated to ensure that safe shutdown can be achieved. The applicant has taken appropriate corrective action to relocate or qualify all affected equipment.

3.11.3.3.4 Demineralized Water Spray

The applicant stated that RBS does not have a spray system. Therefore, it is not necessary to evaluate the effects of spray on equipment important to safety.

3.11.3.3.5 Aging

The aging program requirements for RBS electrical equipment are defined in Category I of NUREG-0588. All degrading influences must be considered and included in the aging program. Justification for excluding pre-aging of equipment in type testing must be established based on equipment design and application, or on state-of-the-art aging techniques. A qualified life is to be established for each equipment item.

In addition to the above, a maintenance/surveillance program must be implemented to identify and prevent significant age-related degradation of electrical and mechanical equipment. The applicant committed to follow the recommendations in RG 1.33, Revision 2, "Quality Assurance Program Requirements (Operation)," which endorses American National Standard ANS-3.2/ANSI N18.1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants." This standard defines the scope and content of a maintenance/surveillance program for safety-related equipment. Provisions for preventing or detecting age-related degradation in safety-grade equipment are specified and include (1) utilizing experience with similar equipment, (2) revising and updating the program as experience is gained with the equipment during the life of the plant, (3) reviewing and evaluating malfunctioning equipment and obtaining adequate replacement components, and (4) establishing surveillance tests and inspections based on reliability analyses, frequency and type of service, or age of the items, as appropriate.

The applicant has described a program that incorporates the above guidelines and has stated that the maintenance/surveillance program is in effect at River Bend.

3.11.3.3.6 Radiation (Inside and Outside Containment)

The applicant has provided values of the radiation levels postulated to exist following a LOCA. The accident radiation environments in primary containment have been defined according to NUREG-0588. For this review, the staff has assumed that the values provided have been determined in accordance with the prescribed criteria. The staff review determined that the values to which the equipment is qualified enveloped the requirements identified by the applicant.

The maximum total radiation dose specified by the applicant for primary containment is 1.7×10^8 rads gamma. In the secondary containment, values of up to 1.8×10^8 rads gamma were used in the evaluation of equipment in areas exposed to recirculating fluid lines. These values are acceptable for use in the qualification of equipment.

3.11.3.4 Outstanding Equipment

For safety-related items not having complete qualification documentation, the applicant has provided commitments for corrective action and schedules for completion. For items identified to date that will not have full qualification before an operating license is issued, analyses have been performed in accordance with 10 CFR 50.49(i) to ensure that the plant can be operated safely pending completion of environmental qualification. These analyses have been submitted for consideration. The staff has reviewed the justifications for interim operation and has concluded that reasonable assurance has been provided that the River Bend plants can be operated safely pending completion of environmental qualification.

3.11.4 Qualification of Equipment

The following subsections presents the staff's assessment based on the applicant's submittal, audit of documentation contained in the applicant's qualification files, and previous staff evaluations of equipment in other plants.

3.11.4.1 Electrical Equipment Important to Safety

The staff has separated the electrical equipment in a harsh environment into two categories: (1) equipment requiring additional information and/or corrective action, (2) equipment considered acceptable, based on the staff's review. Tables 3.11.2 and 3.11.3 list equipment in each of these categories, respectively.

3.11.4.1.1 Equipment Requiring Additional Information and/or Corrective Action

Table 3.11.2 identifies equipment in this category. Corrective action or deficiencies are noted ~~by a letter according to the following legend~~: in the table.

Move to Table

Legend

QD - qualification information being developed, justification for interim operation provided.

The deficiencies have been determined on the basis of all the information available to the staff at the time of review and do not necessarily mean that the equipment is unqualified. However, the deficiencies are cause for concern and require further case-by-case evaluation. The applicant has indicated that all of the concerns identified have been reviewed and all deficiencies identified have been adequately resolved and are auditable. In accordance with 10 CFR 50.49(i) acceptable justifications for interim operation have been submitted for equipment items not having complete qualification.

3.11.4.1.2 Equipment Considered Acceptable

On the basis of the staff review, the items identified in Table 3.11.3 have been determined to be acceptable.

3.11.4.2 Environmental Qualification Audit

On January 26, 27, and 28, 1985, the staff, with assistance from EG&G Idaho, Inc., conducted an audit of the applicant's qualification documentation and equipment installed at the plant. Twelve equipment items were reviewed to

determine if the documents in the qualification files supported the qualification status determined by the applicant.

The equipment items selected for audit were

1. Conax Electrical Penetration (SRN-241211-1)
2. Limitorque Valve Actuators, inside containment (SRN-228212-1)
3. Limitorque Valve Actuators, outside containment with paramount motors (SRN-228212-2)
4. Asco Solenoid Valve (SRN-228218-3)
5. Rosemount Transmitters (SRN-247481-1)
6. Mercury/Buchanan Terminal Boards (SRN-247411-2)
7. Endevco Primary Position Element (SRN-247529-2)
8. Okonite 600V Control Cable (SRN-241240-1)
9. Westinghouse Pump Motor (SRN-237160-1)
10. Hydrogen Igniter Assembly, by Power Systems Division (SRN-211161-1)
11. Namco Limit Switch (SRN-S05B)
12. Sheffer MSIV Actuator (SRN-S05A)

These files were reviewed to determine if qualification has been demonstrated based on the documents contained in the files. Several deficiencies were noted and discussed with the applicant at the time of the audit. These deficiencies were also provided to the applicant in June 1985 and transmitted to the applicant by letter dated July 17, 1985. The applicant responded by letters dated June 19 and July 19, 1985. The staff reviewed the responses and concluded that the deficiencies have been adequately resolved.

As part of the audit, the equipment as actually installed was inspected during a plant walkdown. The purpose of the walkdown was to verify that the manufacturer, model number, location and installation are consistant with qualification documents.

3.11.5 Conclusion

The staff has reviewed the River Bend program for the environmental qualification of electrical equipment important to safety and safety-related mechanical

equipment. The purpose of the review was to determine the adequacy and scope of the qualification program and to verify that the methods used to demonstrate qualification is in compliance with applicable regulations and standards.

Our review has determined that the following license condition should be included in the RBS license:

1. All electrical equipment within the scope of 10 CFR 50.49 must be environmentally qualified by November 30, 1985.

Based on the results of our review, we conclude that the applicant's environmental qualification program is acceptable and that adequate justification for interim operation has been provided for equipment not having complete qualification. We further conclude that the applicant has demonstrated conformance with the requirements for environmental qualification as detailed in 10 CFR 50.49, and relevant parts of GDC 1 and 4, and Sections II, XI, and XVII of Appendix B to 10 CFR 50, and with the criteria specified in NUREG-0588.

Table 3.11.1

Safety-Related Systems River Bend Station

Environmental Qualification Program

Reactor System
Nuclear Boiler System
Recirculation System
CRD Hydraulic System
Standby Liquid Control System
Reactor Protection System
Process Radiation Monitors
RHR System
Low Pressure Core Spray
High Pressure Core Spray
RCIC System
Reactor Water Cleanup System
Fuel Pool Cooling and Cleanup System
Main Control Room Panels
Local Panels and Racks
Standby Service Water System
Normal Service Water System
Instrument and Service Air Systems
Combustible Gas Control System
Standby Gas Treatment System
Containment Ventilation System
Auxiliary Building Ventilation System
Power Conversion System
Condensate Makeup and Drawoff System
Auxiliary AC Power System (Class 1E)
Reactor Plant Component Cooling Water
Equipment and Floor Drainage Systems
Fuel Building Ventilation System
Area Radiation Monitoring System
Leak Detection System

Table 3.11.1

Safety-Related Systems River Bend Station

Environmental Qualification Program

(cont'd)

Main Steam-Position Leakage Control System (MS-PLCS) and Penetration Valve Leakage Control System (PVLCS)

Drywell Ventilation System

Annulus Mixing System

Annulus Pressure Control System

Containment and Drywell Purge System

Post-Accident Sampling System

Table 3.11.2 Equipment requiring corrective action

Component description	Manufacturer	Model number	Deficiency/ corrective action *
1. Cable Repair Kit	Okonite	Okoguard	QD
2. Raychem Heat-Shrink	Raychem	WCFS-N, NMCK, NCBK, NESK, NPK, NMCK8, NHVBC, S1119-6-1500, GCA, EPPA-109N	QD
3. Heat Tracing	Thermon	-	QD
4. Heater	Nuthern	A-1057	QD
5. Motor (Pump)	Reliance	184HP	QD
6. Cable	Rockbestos	-	QD
7. 480V Load Center	Powell Electrical	AKDG	QD
8. 480 Motor Control Center	Gould Inc.	Series 5600	QD
9. Radioactivity Element (Pump)	GA Tech	RD-52, RD-72	QD
10. Control Switches	General Electric	CR 2940	QD
11. Thermal Flow Detecting Element	Fluid Components Inc.	FR72-1R, FR72-4R	QD
12. Electrohydraulic Actuator	Borg Warner	EC	QD
13. Pressure Transmitter	Rosemount	1152 Series	QD
14. NOV-AC/B Insulated Outside Containment	Limitorque/ Paramount	SMC-D4-2, 3	QD

* QD -

ED NOTE: See page 3-10 for info to be added here.

Table 3.11.3 Equipment considered acceptable

Component description	Manufacturer	Model number	Deficiency/ corrective action
Hydrogen Igniter Assemby	Power Systems Division	--	
Resistance Temperature Detector	PYCO	122-3046-04	
Unit Cooler Motor	Westinghouse	445TCZ	
Unit Cooler Motor	Westinghouse	326TCZ	
Unit Cooler Motor	Westinghouse	324TCZ	
Unit Cooler Motor	Westinghouse	256TCZ	
Unit Cooler Motor	Westinghouse	215TCZ	
Unit Cooler Motor	Westinghouse	213TCZ	
Hydrogen Mixing Fan Motor	Westinghouse	TBFC 145T	
Fan, Ventilation and Filter	Westinghouse	OOP 365TZ	
Fan, Ventilation and Filter	Westinghouse	FBFC 143T	
Fan, Ventilation and Filter	Westinghouse	OOP 326TZ	
Fan, Ventilation and Filter	Westinghouse	TEFC	
Fan, Ventilation and Filter	Westinghouse	TBDP449TS	
Limit Switch	NAMCO	EA180	
Solenoid Valve	ASCO	NP8321A5E	
Electrical Penetration	CONAX	--	
Solenoid Valve	TRCP	82B-002	
Solenoid Valve	TRCP	202683-1	
H_2 Recombiner Power Supply	Westinghouse	B	
H_2 Recombiner	Westinghouse	B	
Heater	Nuthern	A-1057	
Flow Switch	CEMCO	RH-15	
Temperature Switch	Fenwal	54-301	
Temperature Switch	Fenwal	54-302	
MOV-AC/RH Insulated Inside and Outside Containment	Limitorque	SB and SMB Series	
MOV-AC/B Insulated Outside Containment	Limitorque	SB, SMB and SMC Series	
MOV-DC/RH Insulated Outside Containment	Limitorque	SMB Series	
Limit Switch	NAMCO	EA-180, EA-740	

Table 3.11.3 Equipment considered acceptable (cont'd)

Component description	Manufacturer	Model number	Deficiency/ corrective action
Solenoid Operated Valve	ASCO	HV-206-832-6F	
Pump Motor	Westinghouse	184T-TEFC, 213T-TEFC	
5KV Power Cables	Anaconda	--	
600V Power Cable	Okonite	--	
600V Control Cable	Okonite		
300V Instrument Cable	Rockbestos	Firewall III	
300V Coax. and Twinax Instrument Cable	Rockbestos	RSS-6	
300V Instrument Cable	Rockbestos	XLPE/Neoprene	
Extension Wire (Thermocouple)	Rockbestos	XLPE/Neoprene	
Instrument Cable	Bran-Rex Co.	--	
Terminal Cabinet Terminal Boards	GE	EB-25	
Splice (Terminal Cabinet)	Raychem	Splice	
Transformer for 480V Load Center	Southern Transformer	1500 KVA	
Terminal Racks-Wire Racks	Mercury/Eaton	Instrument Rack	
Hydrogen Analyzer-Remote Cabinet	Comsip Inc.	Part of KMS* PNL 10A	
Hydrogen Analyzer-Local Cabinet	Comsip Inc.	KIII	
RTD	PYCO	122-3046-12	
RTD	PYCO	122-4030-04	
Solenoid Valve	ASCO	NP8320	
Solenoid Valve	Target Rock	77KK-002, 77KK-003, 77KK-008, 77KK-001, 77KK-004, 77KK-005, 77KK-010, 77KK-011, 77KK-015, 77KK-009, 77KK-012, 77KK-013, 77KK-014	
Position Transmitter Rack	TEC	--	
Primary Position Element	Endevco	E2273AM1	
Position Transmitter	TEC	504A	
Level Transmitter	Gould Inc.	PD3218	
Temperature Element	PYCO	102-9039-11	

Table 3.11.3 Equipment considered acceptable (cont'd)

Component description	Manufacturer	Model number	Deficiency/ corrective action
Insulated Detector	GE	NA-05	
Pressure Switch	Barksdale	TC 9622-3	
Level Switch	Magnetrol	5.0-751	
Limit Switch	NAMCO	EA170-51101	
Pump Motor	GE	5K6336XC322A, 5K6339XC185A, 5K6348XC98A	
MSIV Actuator	Sheffer Corp.	SA-A070	
MSIV Limit Switch	NAMCO	EA740, REV.N	
RCIC Turbine	Terry Corp.	GS-2	
Pump Motor	GE	5K324AN2960	
Solenoid Valve, 3-way	ASCO	HVA-176-816-1	
Pilot Solenoid Valve	VALCOR	V70900-45	
Backup Scram Solenoid Valve	VALCOR	V70900-43	
Explosive Valve	CONAX	7048-17000-01	
Motor (Compressor)	Reliance	326TS	
Motor (Pump)	Reliance	--	
Transformer	Southern	SN-4475-1, 2	
	Transformer Co.	3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13	
120V Distribution Panel	Square D	NQOB	
5KV Switchgear	Brown Boveria	5HK250	
Transmitter	Rosemount	1153B Series	
Electrical Penetration	CONAX	7437-10000,10001, 10002, 10003, 10004, 10005	
MOV-AC/RH Insulated Inside Containment	Limitorque/ Reliance	SMB and SB Series	
Main Steam Safety/Relief Valve	Crosby	HB-65-DF	
Terminal Boards	Mercury/Buchanan	NQB-112	

Appendix —

Lab report from EG&G Idaho, Inc.

(see 3.10.2.6)

SAFETY EVALUATION REPORT
TMI ACTION--NUREG-0737 (II.D.1)
RELIEF AND SAFETY VALVE TESTING
FOR
RIVER BEND STATION
UNIT 1
DOCKET NO. 50-458

1. INTRODUCTION

1.1 Background

Light water reactor experience has included a number of instances of improper performance of relief and safety valves installed in the primary coolant systems. There have been instances of valves opening below set pressure, valves opening above set pressure and valves failing to open or reseat. From these past instances of improper valve performance, it is not known whether they occurred because of a limited qualification of the valve or because of a basic unreliability of the valve design. It is known that the failure of a power-operated relief valve to reseat was a significant contributor to the TMI-2 sequence of events; however, such an event in a Boiling Water Reactor (BWR) would not have the same severe consequences. Nevertheless, these facts led the task force which prepared NUREG-0578[1] to recommend that programs be developed and executed which would reexamine the performance capabilities of BWR safety and relief valves for unusual but credible events. These programs were deemed necessary to reconfirm that the General Design Criteria 14, 15 and 30 of Appendix A to Part 50 of the Code of Federal Regulations, 10 CFR are indeed satisfied.

1.2 General Design Criteria and NUREG Requirements

General Design Criteria 14, 15, and 30 require that (1) the reactor primary coolant pressure boundary be designed, fabricated and tested so as to have an extremely low probability of abnormal leakage, (2) the reactor coolant system and associated auxiliary, control and protection systems be designed with sufficient margin to assure that the design conditions are not exceeded during normal operation or anticipated transient events and (3) the components which are part of the reactor coolant pressure boundary shall be constructed to the highest quality standards practical.

To reconfirm the integrity of relief and safety valve systems and thereby assure that the General Design Criteria are met, the NUREG-0578 position was issued as a requirement in a letter dated September 13, 1979 by the Division of Licensing (DL), Office of Nuclear Reactor Regulation (NRR) to ALL OPERATING NUCLEAR POWER PLANTS. This requirement has since been incorporated as Item II.D.1 of NUREG-0737[2] (Clarification of TMI Action Plan Requirements) which was issued for implementation on October 31, 1980. As stated in the NUREG reports, each boiling water reactor Licensee or Applicant shall:

1. Conduct testing to qualify reactor coolant system relief and safety valves under expected operating conditions for design basis transients and accidents.

2. Determine valve expected operating conditions through the use of analyses of accidents and anticipated operational occurrences referenced in Regulatory Guide 1.70, Rev. 2.

3. Choose the single failures such that the dynamic forces on the safety relief valves are maximized.

4. Use the highest test pressures predicted by conventional safety analysis procedures.

5. Include in the relief and safety valve qualification program the qualification of the associated control circuitry, piping and supports.

6. Test data including criteria for success or failure of valves tested must be provided for Nuclear Regulatory Commission (NRC) staff review and evaluation. These test data should include data that would permit plant-specific evaluation of discharge piping and supports that are not directly tested.

7. Each Licensee or Applicant must submit a correlation or other evidence to substantiate that the valves tested in a generic test program demonstrate the functionability of as-installed primary relief and safety valves. This correlation must show that the test conditions used are equivalent to expected operating and accident conditions as prescribed in the Final Safety Analysis Report (FSAR). The effect of as-built relief and safety valve discharge piping on valve operability must be accounted for if it is different from the generic test loop piping.

2. BWR OWNERS' GROUP RELIEF AND SAFETY VALVE PROGRAM

To respond to the NUREG requirements listed above, the BWR Owners' Group contracted the General Electric Company (GE) to design and conduct a Safety/Relief Valve Test Program.[3] The program describes the safety/relief valves to be tested, the test facility requirements, the test sequence, the valve acceptance criteria and the procedure for obtaining, analyzing and reporting the test data. Prior to its acceptance, the test program received extensive NRC review and comment followed by responses from the GE/BWR Owners' Group. Six NRC questions and Owners' Group responses dealing with justification of the applicability of test results to the in-plant safety/relief valves are contained in the enclosure to Reference 4. The NRC review of the response to these questions is contained in Reference 5. Based on this review, the concerns expressed in the questions were appropriately resolved.

The early BWRs contain a combination of dual function safety/relief valves (SRV), power actuated relief valves (PARV) and single function safety valves (SV). At the River Bend Station, Unit 1, there are 16 dual function SRV's. There are no PARV's or SV's at the River Bend Station.

The qualification of the SRVs for steam discharge under expected operating and accident conditions has been demonstrated by vendor production tests and is confirmed routinely by in-plant startup and operability tests. Based on this, it was agreed that the valves should be tested for those events that result in liquid or two-phase flow at the SRV.

The test sequence and conditions established in the test program were based on an evaluation of expected operating conditions determined through the use of analyses of accident and anticipated operational occurrences referenced in Regulatory Guide 1.70, Rev. 2. Enclosure 2 to Reference 3 provides this evaluation which indicated that there is one event which is significantly likely to occur and can lead to the discharge of liquid or

two-phase flow from the SRVs. This event combined with the single failure requirement of NUREG 0737 results in the conclusion that a test should be performed simulating the alternate shutdown cooling mode which utilizes the SRVs as a return flow path for low pressure liquid to the suppression pool.

At a meeting on March 10, 1981,[6] the BWR Owners' Group presented results of a study by Science Applications, Inc. (SAI) which showed that the probability of getting liquid to the steamline, and hence to the SRV's, is approximately 10^{-2} per reactor year. However, even if the water level increases to the mid-plane of the steam line nozzle on the vessel, which is not likely,[a] the fluid quality at the valve was calculated by GE to be greater than 20%.[3] Because the steam lines typically drop about 45 feet vertically from the vessel nozzles to the horizontal runs on which the SRVs are mounted, much of the liquid which gets to the steam lines would be entrained as droplets. Therefore, the two-phase mixture upstream of the SRVs, should liquid reach the level of the steam lines, would exist as a froth, droplet, annular or stratified flow regime, and slug flow or subcooled liquid flow would be unlikely.

Even if two-phase discharge through a SRV should result in a stuck open valve, the results of the blowdown are not severe. As discussed in Reference 7, historically there have been a total of 53 inadvertent blowdown events due to pressure relief system valve malfunctions from 1969 through April 1978. These events varied in consequences from a short duration pressure transient to a rapid depressurization and cooldown of the primary coolant system from approximately 1100 psig to a few hundred psig. No fuel failures due to these transients have been reported.

In Reference 8, the BWR Owners' Group discusses the consequences of the worst case transient for maintaining the core covered (loss of feedwater) combined with the worst single failure (failure of the high

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a. Feedwater pumps would be tripped prior to the water level reaching the mid-plane by the L8 high level trip, turbine vibration trip, or by operator action.

pressure injection system) and one stuck open relief valve. Reference plant analyses for a BWR/4 and BWR/5 show that the Reactor Core Isolation Cooling (RCIC) system can automatically provide sufficient inventory to keep the core covered. The capability is not a design basis for the RCIC system and not all plants have been analyzed to demonstrate this capability. If a plant should not have this capability, manual depressurization to low pressure core cooling systems will avoid core uncovery for the case of loss of feedwater plus worst single failure plus a stuck open relief valve. Therefore, even for the loss of feedwater transient with the worst single failure, a stuck open relief valve does not uncover fuel.

At the March 10, 1981 meeting,[6] the BWR Owners' Group presented an analysis that showed that even if a slug of subcooled water exists upstream of the SRVs, the probability of rupturing the discharge line is 7×10^{-4} per event. The Staff has not reviewed the supporting analysis for this value; however, even if the failure probability is as high as 10^{-2} per event, the combined probability is no greater than for a steam line break inside containment. GE states that the steam line break, which has been analyzed and found to be acceptable, would be more severe (effects on the core and containment) than a break in a SRV discharge line with a stuck open SRV because the assumed break area is larger.

In summary, based on the BWR operating history of inadvertent SRV blowdowns, the low likelihood of severe consequences, and the bounding design basis steam line break, the staff decided not to require high pressure testing with saturated liquid or subcooled water.

Based on the above, the Applicant has complied with NUREG Requirements 1-4 (Paragraph 1.2 above). That is, an acceptable test program was established which adhered to the Staff guidelines on the selection of test conditions and the maximization of system loads. That portion of Item 5 dealing with the qualification of the associated control circuitry is considered to be satisfied as a result of the anticipated licensing action for compliance with 10 CFR, Part 50.49.

3. BWR OWNERS' GROUP TEST RESULT AND ANALYSIS

In October 1981, the BWR Owners' Group published a technical report[9] documenting the results of the prototypical safety/relief valve tests conducted in accordance with the accepted Test Program.[3] The tests were performed by the General Electric Company for the BWR Owners' Group at the Wyle Laboratory in Huntsville, Alabama. The test report, which was reviewed by the Staff, describes the test facility, the basis for the test conditions and valve selection, the instrumentation and its accuracy, and analyzes the results with respect to valve operability, piping and support loads and the applicability of the test results to the in-plant safety and relief valves.

With the completion of the testing and the submittal of the test report, the Applicant complied with NUREG Requirement No. 6 listed in 1.2 above. However, the subsequent Staff review of the test results generated four plant specific questions stated in Reference 10 which required resolution. Reference 11, representing the River Bend Station response to the four plant specific questions, was submitted for review on May 15, 1985.

4. REVIEW AND EVALUATION

4.1 Review of Test Results and Analysis

An extensive review[12,13] of the test results[9] was conducted by NRC consultants (EG&G Idaho, Inc.) at the Idaho National Engineering Laboratory. The review addressed not only the test results but also the applicability of the test results and equipment to the River Bend Station safety-relief valve systems. The four plant specific questions generated by the review and the Applicant's responses to those questions are discussed in Paragraph 4.4 below.

4.2 Valves Tested

The generic test program required the testing of six different safety/relief valves. Included was a Crosby (8 x R x 10) Safety Relief Valve, Style HB-65-BP. This valve is a direct acting, dual function, spring loaded SRV with no material, dimensional or operational differences compared to the in-plant valves. Thus, the test results are directly applicable to the in-plant valves at the River Bend Station.

4.3 Test Conditions

As discussed in Section 2.0 herein, test conditions to envelop the expected BWR Safety/Relief Valve events were developed in accordance with NRC guidelines. They were accepted and are presented in Reference 3. The review of the test results indicates that the actual test conditions were in accordance with the established test program.

4.4 Evaluation of Responses to Plant Specific Questions

The response to Question No. 1 indicates that there are valve discharge line differences between the test configuration and the in-plant configuration. However, it is pointed out that these differences result in bounding loads on the SRV's. The first segment of test piping downstream of the test valve is comparable in length to in-plant segment (12 ft.),

which would result in an equivalent moment at the test valve. Discharge from the tee quencher at the end of the River Bend SRV discharge line cannot transmit loads to the valve as the test system could because the in-plant line is anchored between the quencher and the valve. Thus, this portion of the response is considered to be acceptable. The second part of the response addressed the back pressure (dynamic, hydraulic) loads on the test and in-plant valves. The Applicant addressed both transient and steady state back-pressure loads. The steady state back pressure for the test valve was forced to be greater than that expected in-plant by installing a predetermined orifice plate in the discharge line before the ram's head and above the water line. The response also indicated that the high pressure steam test preceding the low pressure water test would produce the greater transient back pressures between the two tests. This would be true due to the higher pressure upstream of the SRV and the shorter valve opening time. Based on the above discussion, the response to the first question is considered by the Staff to be acceptable.

The response to the second question described the support system components in the River Bend discharge lines indicating that spring hangers do exist at the River Bend Station whereas the test facility piping did not include spring hangers. The basic argument defending the adequacy of the spring hangers (in fact, all supports) is that they were designed for the much larger, high steam pressure relief valve opening loads. In this case, therefore, sufficient margin is available in the in-plant spring hangers to account for the additional load due to the dead weight in the water-filled, low pressure event. The test results indicated significantly lower dynamic loads during the water discharge event than during the high pressure steam discharge case and the point made in this response (as well as in the response to Question No.1) is that the test program was designed primarily to demonstrate valve and system adequacy under the prototypical water discharge events (i.e., the alternate shutdown cooling mode).

Thus, with the in-plant safety/relief valve discharge piping and support system designed for the high pressure steam discharge event and with the satisfactory response of the test valves, the discharge piping and support

system to the low pressure water blowdown, the reply to the second question is considered by the Staff to be acceptable.

Question No. 3 asked the Applicant to describe and compare expected events at River Bend Station with the test conditions of the generic test program. The Applicant summarizes the analysis procedure[3] using Regulatory Guide 1.70 which arrived at 13 events that would result in liquid or two-phase flow through the SRV's and maximize the dynamic forces on the valve. As indicated in Section 2.0 herein, this analysis concluded that the alternate shutdown cooling mode is the only expected event which will result in liquid at the valve inlet. To simulate this event the test program[3] used a 15-50°F subcooled liquid at 20-250 psig at the SRV inlet prior to valve opening. The Applicant indicates that the fluid/flow conditions tested conservatively bound the River Bend Station conditions expected for the alternate shutdown cooling mode of operation. The Applicant's response to the third question is acceptable to the Staff.

The response to the fourth question addresses the determination and future use of the valve flow coefficient, C_v. The response indicates that the value of the liquid flow coefficient, in itself, is not of direct interest. The flow capacity of the valves as measured during the tests is the data of interest. The flow capacity of the system SRV's is larger than the capacity of the coolant source pump of the residual heat removal (RHR) system and therefore sufficient to remove decay heat. The answer to this question is considered to be acceptable to the Staff.

Considering the above evaluations, the Staff finds that the Applicant for the River Bend Station, Unit 1 has provided an acceptable response to NUREG Item 7 and to the piping and support concerns of NUREG Item 5 (Paragraph 1.2 herein).

4.5 Supporting Information

4.5.1 Additional Questions

Two other questions generated by the staff concerning (1) valve functional deficiencies encountered during invalidated test runs and (2) the

effect of steam cycling on valve performance have been addressed previously by other Licensees using the Crosby (8 x R x 10) SRV. The staff accepted those responses based on the following:

1. Previous submittals by other Licensees have stated, "All the valves subjected to test runs, valid or invalid, opened and closed without loss of pressure integrity or damage." This statement was supported by the Wyle Laboratory test log sheet for the Crosby valve.

2. Although the test program did not subject the valves to steam cycling, the valve vendor has subjected his valves to high pressure steam flow cycling and no loss of valve performance has been noted.

Because of this prior acceptance, the Applicant for the River Bend Station, Unit 1, was not requested to respond to these concerns.

4.5.2 High Pressure Steam Flow/Discharge Piping Response

The applicability of the response of the safety-relief valve discharge piping system to the response of the in-plant piping system has been accepted above. In the test report,[9] it is indicated that, (1) the analytically predicted response of the test piping and supports was comparable to the measured values, and (2) the maximum test piping response to liquid flow was generally less than 30% of that due to test steam flow conditions. Further, as part of the initial review, the loads on the in-plant piping and supports due to steam discharge were found to be acceptable by the Staff. It should also be mentioned that the adequacy of the River Bend SRV discharge piping under high pressure steam loads, is investigated as part of the Staff's normal licensing review.

5. EVALUATION SUMMARY

The Applicant for the River Bend Station, Unit 1 has provided an acceptable response to the requirements of NUREG-0737, and thereby, reconfirmed that the General Design Criteria 14, 15 and 30 of Appendix A to 10 CFR-50 have been met. The rationale for this conclusion is given below.

The Applicant with concurrence by the Staff developed an acceptable Relief and Safety Valve Test Program designed to qualify the operability of the prototypical valves and to demonstrate that their operation would not invalidate the integrity of the associated equipment and piping. The subsequent tests were successfully completed under operating conditions which by analysis bounded the most probable maximum forces expected from anticipated design basis events. The generic test results showed that the valves tested functioned correctly and safely for all steam and water discharge events specified in the test program and that the pressure boundary component design criteria were not exceeded. Analysis and review of the test results and the Applicant justifications indicated the direct applicability of prototypical valve and valve system performances to the in-plant valves and systems intended to be covered by the generic test program.

Thus, the requirements of Item II.D.1 of NUREG 0737 have been met (Items 1-7 in Paragraph 1.2) and, thereby, assure that the reactor primary coolant pressure boundary will have, by testing, a low probability of abnormal leakage (General Design Criterion No. 14) and that the reactor primary coolant pressure boundary and its associated components (piping, valves and supports) have been designed with sufficient margin such that design conditions are not exceeded during relief/safety valve events (General Design Criterion No. 15).

Further, the prototypical tests and the successful performance of the valves and associated components demonstrated that this equipment has been constructed in accordance with high quality standards (General Design Criterion 30).

REFERENCES

1. TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations, NUREG-0578, July 1979.

2. Clarification of TMI Action Plan Requirements, NUREG-0737, November 1980.

3. Letter, D. B. Waters (BWR Owners' Group), to Richard H. Vollmer (NRC) "NUREG-0578 Requirement 2.1.2 - Performance Testing of BWR and PWR Relief and Safety Valves," September 17, 1980.

4. Letter, D. B. Waters, Chairman BWR Owners' Group to D. G. Eisenhut, Director, Division of Licensing, NRR, USNRC, "Responses to NRC Questions on the BWR S/RV Test Program," BWR06-8135, March 31, 1981.

5. Letter, B. F. Saffell to R. E. Tiller, Comments on BWR Owners' Group Responses to NRC Questions on Safety/Relief Valve Low Pressure Program - Saff-95-81, April 23, 1981.

6. Memorandum to Themis P. Speis from Wayne Hodges, "Summary of March 10 Meeting with General Electric to Discuss BWR Liquid Overfill Events," May 1981.

7. Technical Report on Operating Experience with BWR Pressure Relief Systems, NUREG-0462, July 1978.

8. Letter to Darrell G. Eisenhut (NRC) from David B. Waters (BWR Owners' Group), BWROG-80-12, "BWR Owners' Group Evaluation of NUREG-0737 Requirements," December 29, 1980.

9. Analysis of Generic BWR Safety Relief Valve Operability Test Results, General Electric NEDE-2 4988-P, October 1981.

10. Letter from A. Schewencer, USNRC to W. J. Cahill Jr., Gulf States Utilities Company, TMI Action Plan, Item II.D-1, Performance Testing of BWR Relief and Safety Valves, November 9, 1984.

11. Letter, J. E. Booker (Gulf States Utilities Company) to H. R. Denton (NRR-USNRC), "River Bend Station Unit 1, Docket No. 50-458," May 15, 1985.

12. Letter, B. F. Saffell to R. E. Tiller, "Review of BWR/GE Safety Relief Valve Test Report (A6356)" Saff-14-82, January 13, 1982.

13. Letter, B. F. Saffell to D. E. Solecki, "Open Questions-BWR/GE Safety/Relief Valve Test Report, BWR Owners' Safety/Relief Submittals (A6356)"-Saff-178-82, May 4, 1982.

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2 SITE CHARACTERISTICS

2.1 Geography and Demography

2.1.1 Site Location and Description

The nearest rail route, the Illinois Central Gulf Railroad, is at a minimum distance of 2400 feet from the center of the River Bend Unit 1 reactor. Explosive materials are not shipped along this route. The applicant has purchased from the Illinois Central Gulf Railroad 1.2 miles of railroad south of the connection to the River Bend Station's plant access railroad. From this junction northward, past the applicant's property boundary, the Illinois Central Gulf Railroad is abandoning the track which traverses the site in a northwest-southeast direction.

3 DESIGN CRITERIA FOR STRUCTURES, SYSTEMS, AND COMPONENTS

3.6 Protection Against Dynamic Effects Associated With the Postulated Rupture of Piping

3.6.1 Plant Design for Protection Against ~~Dynamic Effects Associated With the~~ Postulated Rupture of Piping (Outside Containment)

In its SER, the staff stated that the applicant's analysis indicated that the main steam isolation valve (MSIV) closure would be expected to terminate the blowdown from a main steamline break within 5.5 seconds. Furthermore, the applicant was to provide detailed information from this analysis for staff review. The applicant has changed the time until MSIV closure to 10.5 seconds. In a submittal dated May 14, 1985, the applicant justified the 10.5-second time as follows. A high flow instrument sensing time of 0.1 second and an instrument delay time of 0.3 second were assumed. The MSIVs are designed to close between 3.0 and 5.0 seconds. This leaves an overall conservatism of 5.1 seconds in the applicant's analysis. This is acceptable.

The staff also stated in the SER that the applicant had not provided sufficient information for the staff to perform an independent calculation to verify the applicant's analysis of the environmental conditions in a compartment after a high-energy-line break (HELB). By letter dated June , 1985, the applicant has subsequently provided the additional information. The staff reviewed the information and performed an independent analysis of the subcompartment environmental conditions following a HELB. Staff analysis indicates that the applicant has appropriately determined the subcompartment conditions by predicting more conservative conditions than those predicted by the staff's independent analysis. This is acceptable.

In its SER, the staff stated that the applicant had not completed its analysis of the rupture of high-energy piping systems and their analysis of compartment flooding resulting from moderate-energy-line cracks. The applicant has now completed its analyses and has provided the results in FSAR Amendment 21. The applicant further has provided the results of an analysis of the effects of the jet impingement from longitudinal cracks in the main steam or feedwater piping in the break exclusion area of the main steam tunnel. The potential jet impingement targets in this area were identified and were assumed to fail to function because of the jet forces. The applicant's analysis indicates that the failed components would not prevent a safe shutdown. A structural evaluation was performed which verified that the structure will retain its integrity considering the effects of the jet impingement, pressure, and flooding. In a submittal dated May 14, 1985, the applicant stated that the main feedwater piping in the steam tunnel had been analyzed and is supported in accordance with seismic Category I criteria. Therefore, the failure of the non-seismic Category I main feedwater piping in the steam tunnel will not adversely affect the safety-related main steamlines or other safety-related components. The staff reviewed these analyses and concludes that the applicant has appropriately used the guidance in Standard Review Plan (SRP) Section 3.6.1 and Branch Technical Position (BTP)

ASB 3-1 in evaluating the effects of high- and moderate-energy pipe failures and the guidance of Regulatory Guide (RG) 1.29 (Rev. 3), Position C.2, as related to protecting safety-related components from failure of non-safety-related components. The applicant has adequately designed and protected areas and systems required for safe shutdown.

On the basis of the above evaluation, the staff concludes that the design of the facility meets the requirements of General Design Criterion (GDC) 4, with regard to protection against environmental conditions and missiles and the guidelines of RG 1.29, Position C.2, concerning protection of safety-related components from the failure of non-safety-related components, and is, therefore, acceptable. The design of the facility meets the acceptance criteria of SRP Section 3.6.1.

3.6.2 Determination of Rupture Location and Dynamic Effects Associated With the Postulated Rupture of Piping

In Section 3.6.2 of the River Bend SER (NUREG-0989 dated May 1984), the staff identified a confirmatory issue regarding the dynamic analysis of the feedwater isolation check valves for the effects of a postulated pipe break in the feedwater piping outside containment. In letters dated December 17, 1984, July 8, 1985, and July 25, 1985, the applicant provided its results for the analyses of the feedwater check valves. The results of the applicant's evaluation were subsequently provided in Appendix 3C.2.2 of FSAR Amendment 17.

In the event of a pipe break in the feedwater piping outside containment, containment isolation is provided by two Atwood & Morrill check valves. Breaks are not postulated in the region between the two check valves because that region is classified as a break exclusion area. The applicant performed dynamic analyses to demonstrate that the feedwater isolation check valves can perform their intended function following a postulated pipe break of the feedwater piping outside containment.

A flow transient analysis was performed using the computer program WATHAM to determine the forcing functions associated with the reverse flow condition during a postulated pipe break. The hydrodynamic torque exerted on the valve disk by the reverse flow was applied to determine the valve closing time and the impact speed of the disk onto its seat.

A stress analysis was performed to determine the ability of the feedwater isolation check valves to withstand the dynamic impact of the valve disk on the seat. An inelastic analysis was performed in accordance with the ASME Code Section III Appendix F (1977) for Class 1 components using the ANSYS computer program. The acceptance criterion was based on the ability of the valves to preclude gross leakage from disk rupture, fracture of the seat/disk interface, or misalignment of the disk. The analysis verified that the structural integrity of the feedwater check valves is maintained.

On the basis of the results of the applicant's analysis confirming the ability of the feedwater isolation check valves to perform their intended function following a feedwater line break outside containment, the staff concludes that the applicant has provided a reasonable basis to conclude that the safety concerns raised in the SER confirmatory issue have been acceptably resolved. Thus, the staff considers the confirmatory issue to be resolved.

3.10 Seismic and Dynamic Qualification of Seismic Category I Mechanical and Electrical Equipment

3.10.1 Seismic and Dynamic Qualification

INPUT TO BE PROVIDED BY THE SEISMIC QUALIFICATION REVIEW TEAM (SQRT)

3.10.1.1 Introduction

As part of the review of the applicant's Final Safety Analysis Report (FSAR) Sections 3.7.3A, 3.7.3B, 3.9.2A, 3.9.2B, 3.10A, and 3.10B, an evaluation is made of the applicant's program for seismic and dynamic qualification of safety-related electrical and mechanical equipment. The evaluation consists of: (1) a determination of the acceptability of the procedures used, standards followed, and the completeness of the program in general and (2) an audit of selected equipment to develop a basis for the judgment of the completeness and adequacy of the seismic and dynamic qualification program.

Guidance for the evaluation is provided by the Standard Review Plan (SRP) Section 3.10, and its ancillary documents, Regulatory Guides (RGs) 1.100, 1.61, 1.89, and 1.92; NUREG-0484; and Institute of Electrical and Electronics Engineers (IEEE) Standards 344-1975 and 323-1974. These documents define acceptable methodologies for the seismic qualification of equipment. Conformance with these criteria is required to satisfy the applicable portions of the General Design Criteria (GDC) 1, 2, 4, 14, and 30 of Appendix A to 10 CFR 50, as well as Appendix B to 10 CFR 50 and Appendix A to 10 CFR 100. Evaluation of the program is performed by a Seismic Qualification Review Team (SQRT) which consists of staff engineers and consultants from the Brookhaven National Laboratory (BNL, Long Island).

3.10.1.2 Discussion

The SQRT reviewed the equipment seismic and dynamic qualification information contained in FSAR Sections 3.7.3A, 3.7.3B, 3.9.2A, 3.9.2B, 3.10A, and 3.10B and visited the plant site from October 29 through November 2, 1984. The purpose of the review and visit was to determine the extent to which the qualification of equipment, as installed at River Bend meets the criteria described above. A representative sample of safety-related electrical and mechanical equipment, as well as instrumentation, included in both nuclear steam supply system (NSSS) and balance of plant (BOP) areas, was selected for the audit. Table 3.1 (revised from SSER 2) identifies the equipment audited. The plant-site visit consisted of field observation of the actual, final equipment configuration and its installation. This was followed by a review of the corresponding qualification documents. The field installation of the equipment was inspected in order to verify and validate equipment modeling employed in the qualification program. During the audit, the applicant presented details of the qualification and in-service inspection program.

3.10.1.3 Summary

Audit Findings

On the basis of the observation of the field installation, review of the qualification documents, responses provided by the applicant to SQRT's questions

during the audit, and correspondence and meetings with the applicant following the audit, the applicant's seismic and dynamic qualification program has been found to be defined and largely implemented. The equipment-specific findings and resolutions as a result of the SQRT audit are identified in Table 3.1. The generic issues are identified in Section 3.10.1.4. The resolution, status, and remarks for each generic issue is provided in Table 3.1A. The license conditions are identified in Section 3.10.1.5. On the basis of the review of the applicant's FSAR and the resolution of issues identified during the SQRT audit, the staff concludes that the seismic and dynamic qualification of safety-related equipment at the River Bend Station, Unit 1, does meet the applicable portions of GDC 1, 2, 4, 14, and 30: Appendix B to 10 CFR 50; and Appendix A to 10 CFR 100.

3.10.1.4 Confirmatory Items

As a result of the plant-site visit, the following generic issues were identified. The staff considers these issues to be of a confirmatory nature. For each of the following issues, the corresponding status, resolution, and remarks are provided in Table 3.2.

(1) Each equipment qualification document package contained summary statements and overall conclusions. The conclusion for each package was that the equipment was fully qualified. However, in many instances, it was observed that evidence necessary to reach the state of complete qualification was unavailable. More recent documentation packages were incomplete and appeared to be put together without adequate checking after the selection of equipment was transmitted to the applicant. Therefore, the applicant was to develop a more systematic program to perform the acceptance review of all safety-related equipment.

(2) Where the qualification document package identifies a need for equipment modification, the applicant was to develop a systematic program to include in the qualification package either a statement indicating implementation of the modification or justification for not implementing the modification.

(3) In many cases, it was observed that the equipment qualification report identified parts with a limited life. Such equipment could be located in either a mild or a harsh environment. The applicant was to develop a systematic procedure for identifying limited-life parts and to ensure their replacement at appropriate intervals during the acceptance review of equipment.

(4) Some equipment had been incorrectly or improperly installed. The applicant was to develop a procedure to check proper mounting of all safety-related equipment consistent with the qualification mounting configuration.

(5) It was observed that the enclosure panel for many pieces of equipment was partially removed or screws had been left loose reportedly in order to facilitate preoperational testing. The applicant was to develop a procedure to ensure that such equipment is returned to the qualified status.

(6) Upon completion of as-built piping analysis for all pipe-mounted safety-related equipment, the applicant must confirm that the g values used for

qualification of this equipment were not lower than the g values obtained from the as-built piping analysis.

(7) The qualification of those pieces of equipment which were originally qualified to meet IEEE Std. 344-1971, should be identified and upgraded to meet the requirements of IEEE Std. 344-1975 as applicable.

(8) Upon completion of the ongoing qualification process, the applicant must confirm that all items of safety-related equipment have been qualified.

3.10.1.5 License Conditions

The River Bend fuel-load, low-power, and full-power licenses are subject to the following conditions:

(1) The full-power license is conditioned upon the applicant modifying all hydraulic control units during the third refueling outage. The modification consists of installing the additional brace used during the qualification test of the equipment. The applicant's letter dated May 15, 1985, indicated that the nitrogen cylinder hangar on the hydraulic control units (1C11*ACTD001) are qualified to a limited life based on safety/relief valve (SRV) fatigue test data.

(2) The low-power license is conditioned upon the applicant performing an independent internal audit of seismic qualification documentation and reporting results to the staff before exceeding 5% of rated power. Issues identified by the audit must be resolved to the staff's satisfaction before exceeding 5% of rated power.

(3) The low-power license is conditioned upon the completion of the seismic qualification of panel board IENB*PNL04A before exceeding 5% of rated power operation. Low-power operation before completion of qualification is justified on the basis of similarity of the unqualified panel board to other panel boards which have been qualified for River Bend requirements.

(4) The low-power license is conditioned upon the completion of the seismic qualification of the HPCS diesel generator before exceeding 5% of rated power. Low-power operation before completion of seismic qualification of the high-pressure core spray (HPCS) diesel generator is justified because the automatic depressurization system (ADS) is redundant to the HPCS system. The ADS is fully qualified.

(5) The low-power license is conditioned upon the completion of seismic qualification of Borg Warner globe valves purchased under GSU Specification No. 247.97 before exceeding 5% of rated power. Low-power operation before completion of seismic qualification is justified because of the similarity between the valve actuators of the unqualified valves and the actuators of valves which have been qualified for River Bend requirements. The qualification of the valve body has been demonstrated by static analysis and static deflection tests.

(6) The low-power and full-power licenses are conditioned upon the completion of the seismic qualification of the in-vessel rack (MPL No. F16-E006) before use during the first refueling outage. The in-vessel rack shall be stored in the plant warehouse before completion of seismic qualification.

3.10.2 Pump and Valve Operability

3.10.2.1 Introduction

To ensure that an applicant has developed and implemented a program regarding the operability qualification of safety-related pumps and valves, the staff performs a two-step audit. The first step is to review FSAR Section 3.9.3.2 for the description of the applicant's pump and valve operability assurance program. The information provided in the FSAR, however, is general in nature and not sufficient by itself to provide confidence in the adequacy of the applicant's overall program for pump and valve operability qualification. To provide this confidence, the Pump and Valve Review Team (PVORT), consisting of staff from Brookhaven National Laboratory (BNL) and the NRC, conducted an on-site audit of a small representative sample of safety-related pumps and valves and supporting documentation.

The criteria by which the audit is performed are described in Section 3.10 entitled "Seismic and Dynamic Qualification of Mechanical and Electrical Equipment" of the Standard Review Plan. SRP Section 3.10 provides detailed guidelines on how to satisfy the requirements of applicable portions of General Design Criteria (GDC) 1, 2, 4, 14, and 30 of Appendix A to 10 CFR 50 as well as Appendix B to 10 CFR 50.

3.10.2.2 Discussion

In performing the first step of the audit, the staff reviewed FSAR Section 3.9.3.2. The onsite audit, or second step, was performed by the PVORT during the week of October 29, 1984. The purpose of this two-step review process is to determine the extent that Gulf States Utilities Company (GSU), the applicant) meets the criteria of SRP Section 3.10. A sample of three nuclear steam supply system (NSSS) and seven balance-of-plant (BOP) components was selected to be audited.

The onsite audit includes a plant inspection of the as-built configuration and installation of the equipment; a review of the normal, accident, and post-accident conditions under which the equipment and systems must operate; the fluid dynamic loads; and a review of the qualification documentation (status reports, test reports, analysis specifications, surveillance programs, and long-term operability program(s), etc.).

A postaudit meeting with the staff and the applicant (GSU) and Stone & Webster (S&W) and General Electric (GE) was held at the NRC offices in Bethesda, Maryland, on May 10, 1985, for the purpose of discussing the confirmatory issues resulting from the NRC site audit and transmitted to GSU in the NRC's February 6, 1985 letter.

Table 3.2 (revised from SSER 2) identifies the equipment audited, the audit findings, and the resolution of equipment-specific items resulting from the audit. In addition to the equipment-specific items, the NRC audit also revealed several items related to the broad program for pump and valve operability assurance. These items are perceived by the staff to be systematic in nature and they cut across specific equipment items. These items are discussed below in Section 3.10.2.3.

3.10.2.3 Generic Items

The generic items determined during the site audit are listed below. Their resolution and status are discussed.

(1) In many instances, it was observed that evidence of complete qualification was unavailable. More recent documentation packages were incomplete and appeared to be put together without checking. The PVORT long forms contained numerous inconsistencies including inconsistent serial numbers, capability, and qualification information of the actual equipment. The applicant is to develop a more systematic program to perform the acceptance review of safety-related pumps and valves.

The applicant has demonstrated during the meetings at Bethesda on May 10 and June 10, 1985, that the qualification documentation and review program has been improved. Additionally, details of the GE and S&W review and approval procedures were presented to the staff during the May 10, 1985, audit in Bethesda. This issue is closed.

(2) During the acceptance review of equipment, a procedure should be developed to identify limited life parts and ensure their replacement at appropriate intervals.

In the applicant's letter of March 29, 1985, reference is made to a November 8, 1985, letter directing S&W to perform a review of all qualification documents submitted by equipment vendors for both BOP and NSSS and to extract the preventive maintenance requirements necessary to maintain qualification. GSU also directed S&W to develop a procedure to address the ongoing review of qualification documents for maintenance and surveillance requirements. This issue is closed.

(3) Procedures should be established to return tested equipment to its qualified status.

The applicant, in the March 29, 1985, letter and the May 10, 1985, meeting in Bethesda, provided additional information and documentation demonstrating the adequacy of the existing procedures. This issue is closed.

(4) Components were found to be incorrectly or improperly installed. Procedures should be established verifying equipment installation requirements and qualification.

The applicant's response in the March 29, 1985, letter and the subsequent audit at Bethesda on May 10, 1985, have satisfied the staff that the discrepancies noted during the site audit are isolated cases and do not require programmatic changes to preclude recurrence. This issue is closed.

(5) All pumps and valves important to safety have had their required preoperational tests completed before fuel load.

The applicant's letter of July 25, 1985, indicates that all preoperational tests are complete. This issue is closed.

(6) All pumps and valves important to safety are qualified before fuel load.

The applicant's letter of July 22, 1985, indicates that of all the safety-related pumps and valves, only the Borg Warner globe valve actuator will be seismically qualified after the fuel load. All other pumps and valves are scheduled to be qualified before fuel loading. The seismic qualification of the Borg Warner globe valve is addressed in Section 3.10.1 of this supplement. In the letter of July 26, 1985, the applicant confirmed that all pumps and valves important to safety have been qualified. This issue is closed.

(7) The applicant shall confirm that new loads resulting from loss-of-coolant accident (LOCA) or analysis of as-built conditions applicable to pumps and valves important to safety do not exceed those loads originally used to qualify the equipment.

In the July 26, 1985, letter, the applicant stated that as-built piping analysis to reconcile the differences between the actual loads and the loads originally used to qualify the pumps and valves is complete. This issue is closed.

3.10.2.4 Evaluation Summary

On the basis of the review of the pump and valve qualification program, observation of the field installation, and the responses provided by the applicant to the PVORT's questions, it is evident that the applicant's pump and valve operability assurance program is properly defined and substantially implemented. The equipment-specific findings resulting from the PVORT site audit have been resolved and are discussed in the Table 3.2. In a letter dated July 22, 1985, the applicant has stated that there are only four items of equipment that will not be qualified before fuel loading. With respect to pump and valve operability qualification, only one of the four items to be qualified after fuel load falls within the pump and valve area of review. That is the Borg Warner globe valve for which the seismic qualification of the valve actuator remains to be completed.

The Borg Warner globe valves are covered by a license condition (see Section 3.10.1 of this supplement). Thus, there are no outstanding open issues with respect to pump and valve operability qualification.

The operability qualification program for safety-related pumps and valves at the River Bend Station, Unit 1, meets the applicable portions of GDC 1, 2, 4, 14, and 30 of Appendix A to 10 CFR 50, Appendix B to 10 CFR 50, and Appendix A to 10 CFR 100.

3.10.2.5

Long-Term Operability Deep Draft Pumps, IE Bulletin 79-15

In response to IE Bulletin 79-15, the applicant identified the deep draft pumps in letters dated September 11, 1979 and October 22, 1979. The resolution of the concern identified in the subject bulletin is addressed by the applicant in FSAR Section 9.2.7.4. The applicant has used the guidelines endorsed by the staff and has completed the performance/endurance testing as indicated in the FSAR. The tests included verification of performance at normal flow for 100 hours.

Where in 3.10.2 is this gt to be placed? How does this relate to SER or SSERs?

The staff concludes, on the basis of the discussion above, that the concerns identified in IE Bulletin 79-15 are satisfactorily resolved and this issue is closed.

Table 3.1 SQRT findings on seismic and dynamic qualification (revised from SSER 2)

SQRT ID No.	Applicant ID No.	Equipment name and description	Safety function	Findings	Resolution	Status	Remarks
NSSS-1	1C11*ACTD001	Hydraulic control unit: Assembly consists of N_2 cylinder, water accumulator and various valves.	Translates scram signal into hydraulic energy to insert the control rod drive and allow its return flow to discharge through the exhaust valve.	The additional brace used during qualification test of the equipment was missing from the installed unit.	Qualified to a limited life based on SRV fatigue test data prior to failure of the hanger and subsequent addition of the second brace.	Closed	See GSU letter RBG-20996 dated 5/15/85. This is a license condition on full-power operation.
NSSS-2	H13-P680	Plant control console: A U-shaped monitoring benchboard.	Supports instruments which are used to monitor and control the safe operation and shutdown of the plant.	The dynamic similarity between the tested specimen and the River Bend console was not established. The test mounting was not documented in the test report. For components qualification, the capability g values were not defined and demonstrated to envelop the required response spectra over the entire frequency range.	Additional documents/ clarifications were provided to show similarity, test mounting, and capability g values.	Closed	See GSU letter RBG-20996 dated 5/15/85.
NSSS-3	C61-P001	Remote shutdown vertical board	Provides redundant means for safe shutdown of the plant.	The installation condition of being next to another cabinet and the wall was not addressed in the qualification.	The vertical board and the adjacent cabinet are being bolted together.	Closed	See GSU letter RBG-20996 dated 5/15/85.
NSSS-4	E1Z-C002A, C	RHR pump and motor	Assembly is required to pump water in the suppression pool during pool cooling modes and LPCI vessel injection modes.		Qualification was verified during audit.	Closed	

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Table 3.1 (Continued)

SQRT ID No.	Applicant ID No.	Equipment name and description	Safety function	Findings	Resolution	Status	Remarks
NSSS-5	H13-P601	Reactor core cooling bench board: Monitoring panel.	Contains instruments that are used for manual control for accident mitigation of the emergency core cooling system.	Dynamic similarity between the tested specimen and the River Bend unit was not established. Test mounting was not completely documented in the test report. For component qualification, the capability g values were not defined and demonstrated to envelop the required response spectra over the entire frequency range. Qualification of some devices below 5 Hz was missing. Controller and recorder units were sliding during tests. It could not be verified from documentation presented whether River Bend panel contains these devices. Site inspection revealed the following: One unistrut was loose. GE ERIS terminals were very flexible.	Additional documents/ clarification were provided to show similarity, test mounting, capability g values, device qualification below 5 Hz, controller and recorder information, and installation correction.	Closed	See GSU letter RBG-20996 dated 5/15/85.
NSSS-6	H13-P670	Neutron/process radiation monitoring system.	Provides information about power levels and power distribution in the reactor, and is tied to a trip system (reactor protection system).	The cabinet was installed with ½"-diameter bolts although the specimen was tested with 5/8"-diameter bolts.	Additional documents were provided to show ½"-diameter bolts adequate for River Bend.	Closed	See GSU letter RBG-20996 dated 5/15/85.

Table 3.1 (Continued)

SQRT ID No.	Applicant ID No.	Equipment name and description	Safety function	Findings	Resolution	Status	Remarks
NSSS-7	H22-P041, 42	Main steam flow local panel	Supports Class 1E devices.	Transmitters were not environmentally aged before seismic testing. Transmitter output variation was detected during testing apparently because incomplete instruction was provided by GE to testing engineers regarding calibration. GSU/GE is to confirm that River Bend installation engineers have received the complete instruction and the transmitters are properly calibrated.	Additional documents were provided to demonstrate qualification of aged transmitters and use or proper calibration.	Closed	See GSU letter RBG-20996 dated 5/15/85.
NSSS-8	B21-F028B	Main steam isolation valve	Isolates the steamline upon demand.	Adequacy of the valve body was not demonstrated. GSU is to confirm compliance with GE's recommendation regarding the following required for qualification: Bracket modification for limit switch. Elimination of junction box. The source of River Bend-specific RRS was not presented during the audit.	Additional documents were provided to indicate that the valve body was analyzed separately and to confirm field modifications.	Closed	See GSU letter RBG-20996 dated 5/15/85.

Table 3.1 (Continued)

SQRT ID No.	Applicant ID No.	Equipment name and description	Safety function	Findings	Resolution	Status	Remarks
BOP-1	1CCP*MOV138	10" motor-operated valve	Is required to isolate the containment and to intercept the water flow of the reactor plant component cooling water system (RPCCW) to the non-regenerative heat exchanger.		Qualification was verified during audit.	Closed	
BOP-2	1RCP*TCA03	Termination cabinets	Are required at penetrations to contain the wiring used in instrumentation monitoring and control of equipment used in various safety-related functions.		Qualification was verified during audit.	Closed	
BOP-3	1EHS*MCC	Motor control center: A two-bay rectangular cabinet containing starters, circuit breakers, switches, terminal, blocks, etc.	Required to provide Class 1E power distribution.	Qualification of devices apparently covered by Gould reports R-STS-10, 31 and analysis was not available for review. Testing of mounting was not documented. It is not clear from test report whether the MCC was tested for 5 OBE and 1 SSE for both the energized and deenergized conditions. Supplemental evaluation report for HE 4-3 circuit breakers was not part of the qualification documentation package.	Additional documents were provided to qualify devices; document test mounting; confirm testing of both energized and deenergized conditions; and circuit breaker qualification was included in the documentation package.	Closed	See GSU letter RBG-20996 dated 5/15/85.

Table 3.1 (Continued)

SQRT ID No.	Applicant ID No.	Equipment name and description	Safety function	Findings	Resolution	Status	Remarks
BOP-4	1E12*PC003	Centrifugal fill pump: A pump/motor assembly.	Maintains the RHR system piping filled and ready for main RHR pump startup.	The site inspection revealed the following deficiencies: The shim stack was loose. One nut in the seal housing was loose and another was missing. The motor nameplate was missing.	Installation deficiencies were corrected.	Closed	See GSU letter RBG-20996 dated 5/15/85.
BOP-5	1HVC*ACU1B	Control building air conditioning unit	Maintains the control building at design temperature and humidity.		Qualification was verified during audit.	Closed	
BOP-6	1HVR*AOD10A	Air-operated damper: It is duct mounted and supported from the ceiling	Operates only during LOCA when it bypasses the air to the standby gas treatment building.		Qualification was verified during audit.	Closed	
BOP-7	1LSV*C3A	Leakage air system compressor: A single rotary compressor with electric motor drive	Provides pressurized air to containment isolation valves to prevent release of fission products after LOCA.		Qualification was verified during audit	Closed	
BOP-8	1SCM*XRC14	Transformer	Furnishes power to various Class 1E instruments as part of the uninterrupted power supply system.	Dynamic similarity between the tested specimen and the River Bend transformer was not established. Test mounting was not completely documented in the test report. Test anomalies were mentioned, but neither described nor justified in the test report.	Additional documents were provided to justify similarity, test mounting, anomalies, and site installation.	Closed	See GSU letter RBG-20996 dated 5/15/85.

Table 3.1 (Continued)

SQRT ID No.	Applicant ID No.	Equipment name and description	Safety function	Findings	Resolution	Status	Remarks
BOP-8 (Cont'd)				Site inspection revealed the following: There was no contact between the baseplate and concrete in most places. Side panels were loose. Baseplate was not addressed in the qualification documents presented.			
BOP-9	1EJS*LDC1A	Load centers	Are required to furnish power distribution to HVAC systems in the control and diesel generator building and also to Class 1E motor control centers.	Only a summary of test report was available. The original Wyle Test Report is needed for review and documentation.	The original test report was made available after the audit.	Closed	See GSU letter RBG-20996 dated 5/15/85.
BOP-10	1SWP*P2B	Standby service water pump: An electrically driven vertical turbine pump.	Provides cooling water for safety-related equipment when normal service water is lost.	Torsional frequency of assembly needs to be computed and compared to motor's operational speed. Operability of pump under seismic load needs to be assured.	Additional documents were provided to justify torsional frequency and pump operability.	Closed	See GSU letter RBG-20996 dated 5/15/85

Table 3.1A Generic issues

Generic* Issue No.	Resolution	Status	Remarks
1, 2	During a meeting between staff and applicant in Bethesda on June 10, 1985, the applicant demonstrated improvement of its qualification documentation and review program. The applicant is committed to perform an independent internal audit and report the results to the NRC before exceeding 5% of rated power.	Confirmatory	See GSU letter RBG-21093, 5/24/85. This is the license condition for exceeding 5% of rated power.
3	The applicant has developed a procedure to perform a review of all qualification documents and extract the preventive maintenance requirements necessary for the qualification.	Confirmatory	See GSU letter RBS-19377, 11/8/84. Effectiveness is to be verified in a audit.
4, 5	During a meeting between staff and applicant in Bethesda on May 10, 1985, the applicant presented FQC inspection reports and startup manual to demonstrate improvement/effectiveness of the existing procedure to identify field installation deficiencies.	Closed	
6	The applicant has confirmed the completion of the as-built piping analysis, and concluded that g values obtained from the analysis are not higher than the g values used to qualify the equipment.	Closed	See GSU letter RBG-21575, 7/19/85.
7	During the May 10, 1985, meeting in Bethesda, the applicant showed that all BOP equipment procurement specifications were upgraded to the IEEE 344-1975 requirements.	Closed	
8	The applicant is committed to confirm completion of qualification of all safety-related equipment	Closed	See GSU letter RBG-20594, 3/29/85.

*See Section 3.10.1.4 of this supplement for statement of issues.

Table 3.2 PVORT findings on operability qualification of pumps and valves (revised from SSER 2)

Plant ID No.	Description	Safety function	Findings/resolution	Status
E22-F015	20" motor-operated gate valve (NSSS)	Opens in response to either a suppression pool high-level signal or a low-condensate tank level, containment isolation.	GSU resolved earlier concerns by providing documentation demonstrating qualification by similarity analysis extending test results from a similar 24" valve.	Closed
ISWP-P2A	Standby service water pump (BOP)	Provides cooling water for safety-related equipment if normal service water is lost	GSU provided additional documentation and analysis results at the May 10, 1985, Bethesda audit responding to staff concerns regarding vibration acceptance criteria and coupling runout values measured during installation alignment. Corrections were also provided clarifying errors noted during the site audit. "Long Term Operability of Deep Draft Pumps" (IE Bulletin 79-15) concerns for this pump are under staff review as noted in the February 6, 1985, letter to GSU from the NRC.	Closed
B33-F060A	20" flow control valve (NSSS)	Maintain pressure boundary integrity.	Satisfactory.	Closed
1E12-MOVF021	14" motor-operated globe valve (BOP)	Containment isolation.	Staff concerns regarding stem leakoff requirements, welding discrepancies, and document issue dates have been satisfactorily addressed in the applicant's letter of March 29, 1985, and during the Bethesda May 10, 1985, audit.	Closed
1HVC-MOV1B	24" motor-operated butterfly valve (BOP)	Isolate main control room during LOCA.	Serial no. discrepancy and staff concerns regarding serialization procedures have been satisfactorily addressed in GSU's March 29, 1985 letter.	Closed

Table 3.2 (Continued)

Plant ID No.	Description	Safety function	Findings/resolution	Status
1CCP-MOV138	10" motor-operated gate valve (BOP)	Outboard containment isolation valve.	Staff concerns regarding serialization discrepancy, stroke time, stem leakoff, space heaters, and checkout procedure revisions have been satisfactorily addressed by GSU in the March 29, 1985, letter and the May 10, 1985, Bethesda audit.	Closed
B21-AOVF32A	20" check valve (BOP)	Containment isolation and reactor coolant pressure boundary.	Satisfactory.	Closed
E33-SOV14	2" solenoid-operated globe valve (BOP)	Provides initial pressurization of main steam positive leak control system.	Staff concerns regarding an installation error noted during site audit, opening air pressure, spring closure forces, and air quality have been satisfactorily addressed in GSU's March 29, 1985, letter and the May 10, 1985, Bethesda audit.	Closed
E12-C002C	RHR pump (NSSS)	Supplies water to the core in the event of an accident. Suppression pool cooling.	Staff concerns regarding the use of manufacturer's acceptance criteria, reject and acceptance tags, serialization discrepancy, conformance to IEEE standards, and age-sensitive components have been satisfactorily addressed in GSU's March 29, 1985, letter and the May 10, 1985, Bethesda audit.	Closed
E12PC003	RHR subsystem fill pump (BOP)	Maintains RHR system piping filled and ready for RHR pump startup.	Staff concerns regarding effects of using suppression pool water and the capability of the pump/motor at reduced voltages have been satisfactorily addressed in GSU's March 19, 1985, letter and the May 10, 1985, Bethesda audit.	Closed

Section
3.10 & 3.11

Version 2

3.10 Seismic and Dynamic Qualification of Seismic Category I Mechanical and Electrical Equipment

3.10.1 Seismic and Dynamic Qualification

Input to be provided by the Seismic Qualification Review Team (SQRT).

3.10.2 Operability Qualification of Pumps and Valves

3.10.2.1 Introduction

To assure that an applicant has developed and implemented a program regarding the operability qualification of safety-related pumps and valves, the Equipment Qualification Branch (EQB) performs a two-step audit. The first step is a review of Section 3.9.3.2 of the FSAR for the description of the applicant's pump and valve operability assurance program. The information provided in the FSAR, however, is general in nature and not sufficient by itself to provide confidence in the adequacy of the licensee's overall program for pump and valve operability qualification. To provide this confidence, the Pump and Valve Review Team (PVORT), consisting of staff from Brookhaven National Laboratory (BNL) and the NRC, conducted an onsite audit of a small representative sample of safety-related pumps and valves and supporting documentation.

The criteria by which the audit is performed are described in Section 3.10 entitled "Seismic and Dynamic Qualification of Mechanical and Electrical Equipment" of the Standard Review Plan. The SRP Section 3.10 provides detailed guidelines on how to satisfy the requirements of applicable portions of General Design Criteria (GDC) 1, 2, 4, 14, and 30 of Appendix A to 10 CFR 50 as well as Appendix B to 10 CFR 50.

3.10.2.2 Discussion

In performing the first step of the audit, the EQB staff reviewed Section 3.9.3.2 of the River Bend Station Unit 1 FSAR. The onsite audit, or second step, was performed by the PVORT during the week of October 29, 1984. The purpose of this two-step review process is to determine the extent that Gulf States Utilities Company (GSU) meets the criteria of Section 3.10 of the SRP. A sample of three NSSS and seven BOP components was selected to be audited.

The onsite audit includes a plant inspection of the as-built configuration and installation of the equipment, a review of the normal, accident, and post-accident conditions under which the equipment and systems must operate, the fluid dynamic loads, and a review of the qualification documentation (status reports, test reports, analysis specifications, surveillance programs, and long-term operability program(s), etc.).

A post-audit meeting with the staff and the utility (GSU) and Stone & Webster and General Electric was held at the Nuclear Regulatory Commission offices in Bethesda, MD for the purpose of discussing the confirmatory issues resulting from the NRC site audit and transmitted to GSU in the NRC's February 6, 1985 letter.

Table 3.10.2.1 identifies the equipment audited, the audit findings, and the resolution of equipment specific items resulting from the audit. In addition to the equipment-specific items, the NRC audit also revealed several items related to the broad program for pump and valve operability assurance. These items are perceived by the staff to be systematic in nature and they cut across specific equipment items. These items are discussed below in Section 3.10.2.3.

3.10.2.3 Generic Items

The generic items determined during the site audit are listed below with their resolution and status.

1. In many instances, it was observed that evidence of complete qualification was unavailable. More recent documentation packages were incomplete and appeared to be put together without checking. The PVORT long forms contained numerous inconsistencies ranging from serial numbers, capability, and qualification information of the actual equipment. The applicant is to develop a more systematic program to perform the acceptance review of safety-related pumps and valves.

   Resolution: The applicant has demonstrated during ~~the post-audit~~ a meeting~~s~~ on June 10, 1985 and May 10, 1985 ~~at~~ in Bethesda that an improvement in the qualification documentation and review program has been achieved. Additionally, details of the GE and SWEC review and approval procedures were presented to the staff during the May 10, 1985 audit in Bethesda.

   Status: Closed.

2. During the acceptance review of equipment, a procedure should be developed to identify limited life parts and ensure their replacement at appropriate intervals.

   Resolution: In the applicant's letter of March 29, 1985, reference is made to a November 8, ~~1985~~ 1984 letter (RBS-19,377) directing SWEC to perform a review of all qualification documents submitted by equipment vendors for both BOP and NSSS and extract the preventive maintenance requirements necessary to maintain qualification. GSU also directed SWEC to develop a procedure to address the ongoing review of qualification documents for maintenance and surveillance requirements. Ref

   Status: Closed.

3. Procedures should be established to return tested equipment to its qualified status.

R

Resolution: The applicant in the March 29, 1985 letter and the May 10, 1985 audit at Bethesda provided additional information and documentation demonstrating the adequacy of the existing procedures.

Status: Closed.

4. Components were found to be incorrectly or improperly installed. Procedures should be established verifying equipment installation requirements and qualification.

Resolution: The applicant's response in the March 29, 1985 letter and the subsequent audit ~~at~~ in Bethesda on May 10, 1985 have satisfied the staff that the discrepancies noted during the site audit are isolated cases and do not require programmatic changes to preclude recurrence.

Status: Closed.

5. All pumps and valves important to safety have had their required preoperational tests completed prior to fuel loads.

R

Status: Applicant's letter of July 26, 1985 indicates that all preoperational tests are completed. This issue is closed.

6. All pumps and valves important to safety are qualified prior to fuel load.

R

Status: Applicant's letter of July 22, 1985 indicates that of all the safety-related pumps and valves, only the Borg Warner globe valve actuator will be seismically qualified after the fuel load. All other pumps and valves are scheduled to be qualified prior to fuel loading. The seismic qualification of the Borg Warner globe valve is addressed in Section 3.10.1 of this report. In their letter of July 26, 1985, the applicant confirmed that all pumps and valves important to safety have been qualified. This issue is closed.

7. The applicant shall confirm that new loads resulting from LOCA or analysis of as-built conditions applicable to pumps and valves important to safety do not exceed those loads originally used to qualify the equipment.

Status: In the July 26, 1985 letter, the applicant stated that as built piping analysis to reconcile the differences between the actual loads and the loads originally used to qualify the pumps and valves is complete. This issue is closed.

3.10.2.4 Evaluation Summary

On the basis of the review of the pump and valve qualification program, observation of the field installation and the responses provided by the applicant to the PVORT's questions, it is evident that the applicant's pump and valve operability assurance program is properly defined and substantially implemented. The equipment-specific findings resulting from the PVORT site audit have been resolved and are discussed in the Table 3.10.2.1. In a letter from Booker to Denton, dated July 22, 1985, the applicant has stated that there are only four of equipment items that will not be qualified prior to fuel loading. Only one of the four items to be qualified after fuel load is related to pump and valve operability qualification. That item, the Borg Warner globe valve, requires completion of seismic qualification of the valve actuator.

The Borg Warner globe valves are covered by a license condition under Section 3.10.1 of this report. Thus, there are no outstanding open issues with respect to pump and valve operability qualification.

The operability qualification program for safety-related pumps and valves at the River Bend Station, Unit 1, meets the applicable portions of GDC 1, 2, 4, 14, and 30 of Appendix A to 10 CFR Part 50, Appendix B to 10 CFR Part 50, and Appendix A to 10 CFR Part 100.

3.10.2.5

Long Term Operability Deep Draft Pumps - IE Bulletin 79-15

In response to the IE Bulletin 79-15, the applicant identified the deep draft pumps in letters dated September 11, 1979 and October 22, 1979. The resolution of the concern identified in the subject bulletin is addressed by the applicant in the FSAR Section 9.2.7.4. The applicant has used the guidelines endorsed by the staff and has completed the performance/endurance testing as indicated in the FSAR. The tests included verification of performance at normal flow for 100 hours.

The staff concludes, on the basis of the discussion above, that the concerns identified in IE Bulletin 79-15 are satisfactorily resolved and this issue is closed.

New?

Table 3.10.2.1 Audit Findings.

Plant ID No.	Description	Safety Function	Findings/Resolution	Status	Remarks
E22-F015	20-inch motor operated gate valve (NSSS).	Open in response to either a suppression pool high-level signal or a low condensate tank level - containment isolation.	Applicant resolved earlier concerns by providing documentation demonstrating qualification by similarity analysis extending test results from a similar 24-inch valve.	Closed	
ISWP-P2A	Standby service water pump (BOP).	Provide cooling water for safety-related equipment if normal service water is lost.	Applicant provided additional documentation and analysis results at the May 10, 1985 meeting. Bethesda ~~audit~~ STEP responding to staff concerns regarding vibration acceptance criteria and coupling run out values measured during installation alignment. Corrections were also provided clarifying errors noted during the site audit. Long Term Operability of Deep Draft Pumps (IE Bulletin 79-15) concerns for this pump ~~is~~ are under staff review as noted in the February 6, 1985 letter to GSU from the NRC.	Closed	

Table 3.10.2.1 Audit Findings.

Plant ID No.	Description	Safety Function	Findings/Resolution	Status	Remarks
B33-F060A	20-inch flow control valve (NSSS).	Maintain pressure boundary integrity.	Satisfactory.	Closed	
1E12-MOVF021	14-inch motor operated globe valve (BOP).	Containment isolation.	Staff concerns regarding stem leakoff requirements, welding discrepancies, and document issue dates have been satisfactorily addressed in the applicant's letter of March 29, 1985 and during the Bethesda May 10, 1985 audit.	Closed	
1HVC-MOV1B	24-inch MO butterfly valve (BOP).	Isolate main control room during LOCA.	Serial no. discrepancy and staff concerns regarding serialization procedures have been satisfactorily addressed in the applicant's March 29, 1985 letter.	Closed	
1CCP-MOV138	10-inch motor operated gate valve (BOP).	Outboard containment isolation valve.	Staff concerns regarding serialization discrepancy, stroke time, stem leakoff, space heaters, and Checkout Procedure revisions have been satisfactorily addressed by the applicant in the March 29, 1985 letter and	Closed	

Table 3.10.2.1 Audit Findings.

Plant ID No.	Description	Safety Function	Findings/Resolution	Status	Remarks
			the May 10, 1985 audit at Bethesda. STET		
B21-AOVF32A	20-inch check valve (BOP).	Containment isolation and reactor cool ent pressure boundary.	Satisfactory.	Closed	
E33-SOV14	2-inch solenoid operated globe valve (BOP).	Provide initial pressurization of main steam positive leak control system.	Staff concerns regarding an installation error noted during site audit, opening air pressure, spring closure forces, and air quality have been satisfactorily addressed in the applicants March 29, 1985 letter and the May 10, 1985 Bethesda audit.	Closed	
E12-C002C	RHR pump (NSSS).	Supply water to the core in the event of an accident. Suppression pool cooling.	Staff concerns regard ing the use of manufacturer's acceptance criteria, reject and acceptance tags, serialization discrepancy, conformance to IEEE, and age sensitive components have been satisfactorily addressed in the applicant's March 29, 1985 letter and the May 10, 1985 Bethesda audit.	Closed	

Table 3.10.2.1 Audit Findings.

Plant ID No.	Description	Safety Function	Findings/Resolution	Status	Remarks
E12PC003	RHR - sub system fill pump (BOP).	Maintain RHR system piping filled and ready for RHR pump startup.	Staff concerns regarding effects of using suppression pool water and the capability of the pump/motor at reduced voltages have been satisfactorily addressed in the applicant's March 29, 1985 letter and the May 10, 1985 Bethesda audit.	Closed.	

3.10 Seismic and Dynamic Qualification of Safety-Related Electrical and Mechanical Equipment

3.10.1 Seismic and Dynamic and Qualification

3.10.1.1 Introduction

As part of the review of the applicant's Final Safety Analysis Report (FSAR) Sections 3.7.3 A, 3.7.3 B, 3.9.2 A, 3.9.2 B, 3.10 A and 3.10 B, an evaluation is made of the applicant's program for seismic and dynamic qualification of safety-related electrical and mechanical equipment. The evaluation consists of: (1) a determination of the acceptability of the procedures used, standards followed, and the completeness of the program in general, and (2) an audit of selected equipment to develop a basis for the judgement of the completeness and adequacy of the seismic and dynamic qualification program.

Guidance for the evaluation is provided by the Standard Review Plan (SRP) Section 3.10, and its ancillary documents, Regulatory Guides (R.G.) 1.100, 1.61, 1.89, and 1.92, NUREG-0484, and Institute of Electrical and Electronics Engineers (IEEE) Standards 344-1975 and 323-1974. These documents define acceptable methodologies for the seismic qualification of equipment. Conformance with these criteria is required to satisfy the applicable portions of the General Design Criteria 1, 2, 4, 14, and 30 of Appendix A to 10 CFR Part 50, as well as Appendix B to 10 CFR Part 50 and Appendix A to 10 CFR Part 100. Evaluation of the program is performed by a Seismic Qualification Review Team (SQRT) which consists of staff engineers ~~from the Equipment Qualification Branch (NRC/EQB)~~ and consultants from the Brookhaven National Laboratory (BNL, Long Island).

3.10.1.2 Discussion

The SQRT has reviewed the equipment seismic and dynamic qualification information contained in the FSAR Sections 3.7.3 A, 3.7.3 B, 3.9.2 A, 3.9.2 B, 3.10 A and 3.10 B and made a plant site visit from October 29 through November 2, 1984. The purpose was to determine the extent to which the qualification of equipment, as installed at River Bend meets the criteria described above. A representative

sample of safety-related electrical and mechanical equipment, as well as instrumentation, included in both Nuclear Steam Supply System (NSSS) and Balance of Plant (BOP) areas ~~scopes~~, was selected for the audit. Table 3.10.1.1 identifies the equipment audited. The plant-site visit consisted of field observation of the actual, final equipment configuration and its installation. This was followed by a review of the corresponding qualification documents. The field installation of the equipment was inspected in order to verify and validate equipment modeling employed in the qualification program. During the audit the applicant presented details of the qualification and in-service inspection program.

3.10.1.3 Summary of Audit Findings

On the basis of the observation of the field installation, review of the qualification documents, responses provided by the applicant to SQRT's questions during the audit, and correspondence and meetings with the applicant following the audit, the applicant's seismic and dynamic qualification program has been found to be defined and largely implemented. The equipment-specific findings and resolutions as a result of the SQRT audit are identified in Table 3.10.1.1. The generic issues are identified in section 3.10.1.4. The resolution, status and remarks for each generic issue is provided in Table 3.10.1.2. The license conditions are identified in Section 3.10.1.5. Based upon review of the applicant's FSAR and the resolution of issues identified during the SQRT audit, the staff concludes that the seismic and dynamic qualification of safety-related equipment at the River Bend Station, Unit 1, does meet the applicable portions of GDC 1, 2, 4, 14 and 30 of Appendix A to 10 CFR Part 50, Appendix B to 10 CFR Part 50, and Appendix A to 10 CFR Part 100.

3.10.1.4 Confirmatory Issues

As a result of the plant site visit the following generic issues were identified. The staff considers these issues to be of a confirmatory nature. For each of the following issues the corresponding status, resolution, and remarks are provided in Table 3.10.1.2.

1. Each equipment qualification document package contained summary statements and overall conclusions. The conclusion for each package was that the equipment was fully qualified. However, in many instances it was observed

that evidence necessary to reach the state of complete qualification was unavailable. More recent documentation packages were incomplete and appeared to be put together without adequate checking after the selection of equipment was transmitted to the applicant. Therefore, the applicant was to develop a more systematic program to perform the acceptance review of all safety-related equipment.

2. Where the qualification document package identifies a need for equipment modification, the applicant was to develop a systematic program to include in the qualification package either a statement indicating implementation of the modification or justification for not implementing the modification.

3. In many cases, it was observed that the equipment qualification report identified parts with a limited-life. Such equipment could be located in either a mild or a harsh environment. The applicant was to develop a systematic procedure for identifying limited-life parts and to ensure their replacement at appropriate intervals during the acceptance review of equipment.

4. There ~~were~~ was equipment ~~pieces~~ found to be incorrectly or improperly installed. The applicant was to develop a procedure to check proper mounting of all safety-related equipment consistent with the qualification mounting configuration.

5. It was observed that for many pieces of equipment the enclosure panel was partially removed or screws were loose reportedly in order to facilitate preoperational testing. The applicant was to develop a procedure to insure that such equipment is returned to the qualified status.

6. Upon completion of as-built piping analysis for all pipe-mounted safety-related equipment, the applicant must confirm that the g-values used for qualification of these equipment were not lower than the g-values obtained from the as-built piping analysis.

7. The qualification of those pieces of equipment which were originally qualified to meet IEEE Std 344-1971, should be identified and upgraded to meet the requirements of IEEE Std 344-1975 as applicable.

8. Upon completion of the on-going qualification process, the applicant must confirm that all safety-related equipment have been qualified.

3.10.1.5 License Conditions

The following license conditions will be incorporated into the body of the operating license:

~~The River Bend Fuel Load, Low Power and Full Power Licenses are subject to the following conditions:~~

1. The applicant shall, prior to startup following the third refueling outage, complete modifications to the ~~Full Power License is conditioned upon the applicant modifying all~~ hydraulic control units. ~~during the third refueling outage~~. The modification consists of installing the additional brace used during the qualification test of the equipment. The applicant's letter RBG-20996 dated May 15, 1985 indicated that the Nitrogen Cylinder Hangar on the Hydraulic Control Units (ICII*ACTD001) are qualified to a limited life based on SRV fatigue test data.

2. The ~~Low Power License is conditioned upon~~ the applicant shall, prior to exceeding five percent rated power, perform ~~performing~~ an independent internal audit of seismic qualification documentation and ~~reporting~~ report the results to the staff, ~~prior to exceeding 5% power~~. Issues identified by the audit must be resolved to the staff's satisfaction prior to exceeding 5% power.

3. The applicant shall, prior to exceeding five percent rated power, complete ~~the qualification~~ ~~Low Power License is conditioned upon the completion of~~ the seismic qualification of panel board IENB*PNL04A, ~~prior to exceeding 5% power operation.~~ Low power operation prior to completion of qualification is justified based on similarity of the unqualified panel board to other panel boards which have been qualified for River Bend requirements.

4. The applicant shall, prior to exceeding five percent rated power, complete ~~Low Power License is conditioned upon the completion of~~ the seismic qualification of the HPCS Diesel Generator, ~~prior to exceeding 5% power.~~ Low power operation prior to completion of seismic qualification of the

HPCS Diesel Generator is justified because the Automatic Depressurization System (ADS) is redundant to the HPCS system. The ADS is fully qualified.

5. The applicant shall, prior to exceeding 5 percent rated power, complete the ~~Low Power License is conditioned upon the completion of~~ seismic qualification of Borg Warner globe valves purchased under GSU specification No. 247.97, ~~prior to exceeding 5% power~~. Low power operation prior to completion of seismic qualification is justified because of similarity between the valve actuators of the unqualified valves and the actuators of valves which have been qualified for River Bend requirements. The qualification of the valve body has been demonstrated by static analysis and static deflection tests.

6. The applicant shall complete ~~Low Power and Full Power Licenses are conditioned upon the completion of~~ the seismic qualification of the In-Vessel Rack (MPL No. F16-E006) prior to its use. ~~during the first refueling outage~~. ~~The In-Vessel Rack shall be stored in the plant warehouse prior to completion of seismic qualification.~~

Table 3.10.1.1

SQRT ID No.	Applicant ID No.	Equipment Name and Description	Safety Function	Findings	Resolution	Status	Remarks
NSSS-1	1C11*ACTD001	Hydraulic Control Unit. Assembly consists of N_2 cylinder, water accumulator and various valves.	Translates scram signal into hydraulic energy to insert the control rod drive and allow its return flow to discharge through the exhaust valve.	The additional brace used during qualification test of the equipment was missing from the installed unit.	Qualified to a limited life based on SRV fatigue test data prior to failure of the hanger and subsequent addition of the second brace.	Closed	See GSU letter RBG-20996 dated 5-15-85. This is a License Condition on Full Power Operation.
NSSS-2	H13-P680	Plant Control Console. A U-shaped monitoring benchboard.	The console supports instruments which are used to monitor and control the safe operation and shutdown of the plant.	1. The dynamic similarity between the tested specimen and the River Bend console was not established. 2. The test mounting was not documented in the test report. 3. For components qualification, the capability g-values were not defined and demonstrated to envelop the RRS over the entire frequency range.	Additional documents/ clarifications were provided to show similarity, test mounting, and capability g-values.	Closed	See GSU letter RBG-20996 dated 5-15-85.
NSSS-3	C61-P001	Remote Shutdown Vertical Board	It provides redundant means for safe shutdown of the plant.	The installation condition of being next to another cabinet and the wall was not addressed in the qualification.	The vertical board and the adjacent cabinet are being bolted together.	Closed	See GSU letter RBG-20996 dated 5-15-85.

Table 3.10.1.1 (Continued)

SQRT ID No.	Applicant ID No.	Equipment Name and Description	Safety Function	Findings	Resolution	Status	Remarks
NSSS-4	E1Z-C002A,C	RHR Pump and Motor	The assembly is required to pump water in the suppression pool during pool cooling modes and LPCI vessel injection modes.		Qualification verified during audit	~~Qualified~~ Closed	
NSSS-5	H13-P601	Reactor Core Cooling Bench Board. A monitoring panel.	It contains instruments that are used for manual control for accident mitigation of the emergency core cooling system.	1. Dynamic similarity between the tested specimen and the River Bend was not established. 2. Test mounting was not completely documented in the test report. 3. For component qualification, the capability g-values were not defined and demonstrated to envelop the RRS over the entire frequency range. 4. Qualification of some devices below 5 Hz was missing. 5. Controller and recorder units were sliding during tests. It could not be verified from documentation presented whether River Bend panel contains these devices.	Additional documents/ clarification were provided to show similarity, test mounting, capability g-values, device qualification below 5 Hz, controller and recorder information, and installation correction.	Closed	See GSU letter RBG-20996 dated 5-15-85.

Table 3.10.1.1 (Continued)

SQRT ID No.	Applicant ID No.	Equipment Name and Description	Safety Function	Findings	Resolution	Status	Remarks
NSSS-5 (Cont'd)				6. Site inspection revealed the following: a) One unistrut was loose. b) GE ERIS terminals were very flexible.			
NSSS-6	H13-P670	Neutron/Process Radiation Monitoring System.	Provides information about power levels and power distribution in the reactor, and is tied to a trip system (Reactor Protection System).	The cabinet was installed with 1/2" diameter bolts although the specimen was tested with 5/8" diameter bolts.	Additional documents provided to show ½ in. dia. bolts adequate for River Bend.	Closed	See GSU letter RBG-20996 dated 5-15-85.
NSSS-7	H22-P041,42	Main Steam Flow Local Panel	It supports Class 1E devices	1. Transmitters were not environmentally aged prior to seismic testing. 2. Transmitter output variation was detected during testing apparently due to incomplete instruction provided by GE to testing engineers regarding calibration. GSU/GE is to confirm that River Bend installation engineers have received the complete instruction and the transmitters are properly calibrated.	Additional documents provided to demonstrate qualification of aged transmitters and use or proper calibration.	Closed	See GSU letter RBG-20996 dated 5-15-85.

Table 3.10.1.1 (Continued)

SQRT ID No.	Applicant ID No.	Equipment Name and Description	Safety Function	Findings	Resolution	Status	Remarks
NSSS-8	B21-F028B	Main Steam Isolation Valve	It isolates the steam line upon demand.	1. Adequacy of the valve body was not demonstrated. 2. GSU is to confirm compliance with GE's recommendation regarding the following required for qualification: a) Bracket modification for Limit Switch. b) Elimination of junction box. 3. The source of River bend specific RRS was not presented during the audit.	Additional documents provided to indicate that the valve body was analyzed separately and to confirm field modifications.	Closed	See GSU letter RBG-20996 dated 5-15-85.
BOP-1	1CCP*MOV138	10" Motor Operated Valve	The valve is required to isolate the containment and to intercept the water flow of the reactor plant component cooling water system (RPCCW) to the non-regenerative heat exchanger.		Qualification verified during audit	~~Qualified~~ Closed	
BOP-2	1RCP*TCA03	Termination ~~Cables~~ Cabinet	The cabinets are required at penetrations to contain the wiring used in instrumentation monitoring and control of equipment used in various safety related functions.		Qualification verified during audit	~~Qualified~~ Closed	

Table 3.10.1.1 (Continued)

SQRT ID No.	Applicant ID No.	Equipment Name and Description	Safety Function	Findings	Resolution	Status	Remarks
BOP-3	1EHS*MCC	Motor Control Center. A two-bay rectangular cabinet containing starters, circuit breakers, switches, terminal, blocks, etc.	MCC is required to provide Class 1E power distribution.	1. Qualification of devices apparently covered by Gould reports R-STS-10,31 and analysis was not available for review. 2. Testing mounting was not documented. 3. It is not clear from test report whether the MCC was tested for 5 OBE and 1 SSE for both the energized and de-energized conditions. 4. Supplemental evaluation report for HE 4-3 circuit breakers was not part of the qualification documentation package.	Additional documents provided to qualify devices; document test mounting; confirm testing of both energized and de-energized conditions; and inclusion of circuit breaker qualification in the documentation package.	Closed	See GSU letter RBG-20996 dated 5-15-85.
BOP-4	1E12*PC003	Centrifugal fill pump. A pump/motor assembly.	It maintains the RHR system piping filled and ready for main RHR pump startup.	The site inspection revealed the following deficiencies: 1. The shim stack was loose. 2. One nut in the seal housing was loose and another was missing. 3. The motor name plate was missing.	Installation deficiencies were corrected.	Closed	See GSU letter RBG-20996 dated 5-15-85.

Table 3.10.1.1 (Continued)

SQRT ID No.	Applicant ID No.	Equipment Name and Description	Safety Function	Findings	Resolution	Status	Remarks
BOP-5	1HVC*ACU1B	Control building air conditioning unit.	It maintains the control building at design temperature and humidity.		Qualification Verified During Audit	~~Qualified~~ Closed	
BOP-6	1HVR*AOD10A	Air operated damper. It is duct mounted and supported from the ceiling.	It operates only during LOCA when it bypasses the air to the Standby Gas Treatment Building.		"	~~Qualified~~ Closed	
BOP-7	1LSV*C3A	Leakage Air system compressor. A single rotary compressor with electric motor drive	It provides pressurized air to containment isolation valves to prevent release of fission products after LOCA.		"	~~Qualified~~ Closed	
BOP-8	1SCM*XRC14	Transformer	It furnishes power to various Class 1E instruments as part of the Uninterrupted Power Supply System.	1. Dynamic similarity between the tested specimen and the River Bend transformer was not established. 2. Test mounting was not completely documented in the test report. 3. Test anomalies were mentioned, but neither described nor justified in the test report. 4. Site inspection revealed the following: a) There was no contact between the base plate and concrete in most places	Additional documents provided to justify similarity, test mounting, anomalies, and site installation.	Closed	See GSU letter RBG-20996 dated 5-15-85.

Table 3.10.1.1 (Continued)

SQRT ID No.	Applicant ID No.	Equipment Name and Description	Safety Function	Findings	Resolution	Status	Remarks
BOP-8 (Cont'd)				b) Side panels were loose c) Base plate was not addressed in the qualification documents presented.			
BOP-9	1EJS*LDC1A	Load Centers	They are required to furnish power distribution to HVAC systems in the Control and Diesel Generator Building and also to Class 1E Motor Control Centers.	Only a summary of test report was available. The original Wyle Test Report is needed for review and documentation.	The original test report was made available after the audit.	Closed	See GSU letter RBG-20996 dated 5-15-85.
BOP-10	1SWP*P2B	Standby Service water pump. An electrically driven vertical turbine pump.	It provides cooling water for safety related equipment when normal service water is lost.	1. Torsional frequency of assembly needs to be computed and compared to motor's operational speed. 2. Operability of pump under seismic load needs to be assured.	Additional documents provided to justify torsional frequency and pump operability.	Closed	See GSU letter RBG-20996 dated 5-15-85

Table 3.10.1.2

Generic Issues

Generic* Issue No.	Resolution	Status	Remarks
1, 2	During a meeting between staff and applicant in Bethesda on June 10, 1985, the applicant demonstrated improvement of their qualification documentation and review program. The applicant is committed to perform an independent internal audit and report the results to the NRC prior to exceeding 5% power.	Confirmatory	See GSU letter RBG-21093, 5-24-85. This is License Condition for exceeding 5% power.
3	The applicant has developed a procedure to perform a review of all qualification documents and extract the preventive maintenance requirements necessary for the qualification.	Confirmatory	See GSU letter RBS-19377, 11-8-84. Effectiveness to be verified in a future audit.
4, 5	During a meeting between staff and applicant in Bethesda on May 10, 1985, the applicant presented FQC inspection reports and start-up manual to demonstrate improvement/effectiveness of the existing procedure to identify field installation deficiencies.	Closed	
6	The applicant has confirmed the completion of the as-built piping analysis, and concluded that g-values obtained from the analysis are not higher than the g-values used to qualify the equipment.	Closed	See GSU letter RBG-21575, 7-19-85.
7	During the May 10 meeting in Bethesda, the applicant showed that all BOP equipment procurement specifications were upgraded to the IEEE 344-1975 requirements.	Closed	

*See section 3.10.1.4 of this SER for statement of issues.

Table 3.10.1.2 (Continued)

Generic* Issue No.	Resolution	Status	Remarks
8	The applicant is committed to confirm completion of qualification of all safety-related equipment.	Confirmatory	See GSU letter RBG-20594 3-29-85.

3.10.2.6

~~3.10.2.6~~ Safety and Relief Valve Testing (TMI item II.D.1)

The staff with the assistance of consultants from EG+G Idaho, Inc. has completed its review of information submitted by the applicant ~~&~~ concerning testing of safety and relief valves for River Bend 1. The staff finds the information submitted demonstrates the ability of the reactor coolant system relief and safety valves to function under expected operating conditions for design-basis transients and accidents as defined under TMI item II.D.1. The details of this review are included in Appendix ___.

3.10.2.7 Verification of ~~Quali~~ the Qualification of ADS Accumulators (TMI item II.K.3.28)

SAFETY EVALUATION
TMI ACTION PLAN II.K.3.28 VERIFY QUALIFICATION
OF ACCUMULATORS ON ADS VALVES
RIVER BEND STATION UNIT 1
DOCKET NO. 50-458

3.10.2.7.1

~~I.~~ BACKGROUND

Safety Analysis Reports (SARs) claim that air ~~(~~or nitrogen~~)~~ accumulators for the automatic depressurization system (ADS) valves are provided with sufficient capacity to cycle the valves open five times at design pressures. General Electric (GE) has also stated that the Emergency Core Cooling Systems (ECCS) are designed to withstand a hostile environment and still perform their function for 100 days following an accident. Licensees and applicants must demonstrate that the ADS valves, accumulators, and associated equipment and instrumentation meet the requirements specified in the plant's FSAR and are capable of performing their functions during and following exposure to hostile environments, taking no credit for non-safety-related equipment or instrumentation. Additionally, air (or nitrogen) leakage through valves must be accounted for in order to assure that enough inventory of compressed air is available to cycle the ADS valves. If this cannot be demonstrated, it must be shown that the accumulator design is still acceptable.

3.10.2.7.2

~~4.~~ DISCUSSION

The commitment to satisfy the requirement of TMI Action Item II.K.3.28 for the River Bend Station, Unit 1 is discussed in the following submittals.

A. Gulf States Utilities Company letter from J.E. Booker to H.R. Denton, NRC, dated April 9, 1984, response to a request for additional information.

B. Gulf States Utilities Company letter from J.E. Booker to H.R. Denton, NRC, dated May 13, 1985.

3.10.2.7.3

~~3.~~ DEMONSTRATION OF OPERABILITY

The design of the River Bend Station is such that the ADS will be available for 100 days following an accident. Each ADS valve is equipped with a 60 gallon accumulator designed for two (2) actuations at 70 percent of drywell design pressure which is equivalent to 4 to 5 actuations at atmospheric pressure. During normal plant operation, air is supplied from the non-nuclear safety (NNS) main steam system air compressors. Post-LOCA air requirements are supplied from the Penetration Valve Leakage Control System (PVLCS), a nuclear safety related Seismic Category I system.

The realignment from the main steam system air compressors to the PVLCS is performed by the plant operators from the main control room.

The PVLCS is manually actuated approximately 20 minutes after a LOCA. Prior to the manual actuation, the system is in an automatic mode and maintains the accumulators at a preset pressure. Following a loss of off-site power, the PVLCS initiation is delayed to avoid overloading due to starting currents. The ADS accumulators are designed and maintained with sufficient inventory to permit the required actuations during this period, assuming a leakage of 1 SCFH.

FSAR Section 9.3.6.3.1 indicates that the PVLCS accumulators are maintained with enough air to meet all short-term requirements of the PVLCS, the MS-PLCS, and the main steam safety/relief valve system.

~~Technical Specification~~ Surveillance requirements should be incorporated in the RBS-1 technical specifications associated with the ADS accumulator system and backup system ~~verifies~~ that the PVLCS accumulator pressure is greater than 101 psig. ~~at least once per 24 hours.~~ to verify at least once every 24 hours

The allowable leakage rate of 1 SCFH for the ADS air accumulator sub-system is compatible with the Emergency Core Cooling System (ECCS) performance evaluations and assumptions, and the calculations for sizing the ADS air supply system. Additionally, no credit was taken for non-safety related equipment or instrumentation when establishing the allowable leakage criteria.

The air accumulator sub-system is designed to withstand Seismic Category I loads and post-accident environments.

The ADS air accumulator sub-system is defined as all the components between (and including) the check valve located on the inlet side of the accumulator and the associated main steam safety relief valve.

3.10.2.7.4

~~4.~~ EVALUATION

~~4.1~~ The primary source of air for the ADS accumulators is from the non-nuclear safety related main steam system air compressors. Backup to this system is the nuclear safety related PVLCS. The applicant states that the PVLCS is placed in service approximately 20 minutes after it has been ascertained that a LOCA has occurred. This realignment is accomplished in the main control room. The 20-minute period is approximately equal to the time required for the PVLCS air compressors to be loaded onto the standby power supplies. The applicant has ~~provided a statement verifying~~ stated that the ADS accumulators have sufficient inventory to assure operability of the ADS valves during this 20-minute interval.

The accumulator on each ADS valve has a 60-gallon capacity which is designed for two actuations at 70 percent of drywell design pressure. This capability is equivalent to 4 to 5 actuations at atmospheric pressure.

The staff concludes that the applicant has demonstrated the long and short term capability of the automatic depressurization system and is therefore acceptable.

4.2 The applicant states that the allowable leakage rate of 1 SCFH is compatible with the ECCS performance evaluations and assumptions, and the calculations for sizing the ADS air supply. Therefore, accounting for (a) the capacity of the accumulators, (b) that the ECCS is a NSSS (GE) designed system, and (c) that previous submittals have discussed in detail the basis for the allowable leakage criteria, the staff concludes that the allowable leakage criteria of 1 SCFH address the concerns in this area and is acceptable.

4.3 The applicant has provided information acceptable to the staff indicative of the development of surveillance, maintenance, and leak testing programs for the ADS accumulator system and associated alarms and instrumentation.

4.4 The applicant has provided information confirming that:

- the backup air supply system, PVLCS, is seismically and environmentally qualified, and

- the accumulators and associated equipment are capable of performing their functions during and following an accident, while taking no credit for non-safety related equipment and instrumentation.

5. CONCLUSION

Based on the information provided by the applicant summarized in Section 3 and the evaluation performed highlighted in Section 4, the staff concludes that the Gulf States Utilities Company has verified accumulators on ADS valves for River Bend Station Unit 1, thereby satisfying the requirements of TMI Action Item II.K.3.28.

Safety Evaluation Report
Office of Nuclear Reactor Regulation
Equipment Qualification Branch
Docket No. 50-458

3.11 Environmental Qualification of Electrical Equipment Important to Safety and Safety-Related Mechanical Equipment

3.11.1 Introduction

Equipment that is used to perform a necessary safety function must be demonstrated to be capable of maintaining functional operability under all service conditions postulated to occur during its installed life for the time it is required to operate. This requirement--which is embodied in General Design Criteria (GDC) 1 and 4 of Appendix A and Sections III, XI, and XVII of Appendix B to 10 CFR 50--is applicable to equipment located inside as well as outside containment. More detailed requirements and guidance relating to the methods and procedures for demonstrating this capability for electrical equipment have been set forth in 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants"; NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment, "which supplements the Institute of Electrical and Electronics Engineers (IEEE) Standard 323; and various NRC Regulatory Guides (RGs) and industry standards.

3.11.2 Background

NUREG-0588 was issued in December 1979 to promote a more orderly and systematic implementation of equipment qualification programs by industry and to provide guidance to the NRC staff for its use in ongoing licensing reviews.

The positions contained in that report provide guidance on (1) how to establish environmental service conditions, (2) how to select methods that are considered

appropriate for qualifying equipment in different areas of the plant, and (3) other areas such as margin, aging, and documentation. In February 1980, the NRC asked certain near-term OL applicants to review and evaluate the environmental qualification documentation for each item of safety-related electrical equipment and to identify the degree to which their qualification programs were in compliance with the staff positions discussed in NUREG-0588.

IE Bulletin 79-01B, "Environmental Qualification of Class 1E Equipment," issued by the NRC Office of Inspection and Enforcement (IE) on January 14, 1980, and its supplements dated February 29, September 30, and October 24, 1980, established environmental qualification requirements for operating reactors. This bulletin and its supplements were provided to operating license (OL) applicants for consideration in their reviews.

A final rule on environmental qualification of electrical equipment important to safety for nuclear power plants became effective on February 22, 1983. This rule, Section 50.49 of 10 CFR 50, specifies the requirements to be met for demonstrating the environmental qualification of electrical equipment important to safety located in a harsh environment. In conformance with 10 CFR 50.49, electrical equipment for River Bend Station (RBS), Unit 1 may be qualified according to the criteria specified in Category 1 of NUREG-0588.

The qualification requirements for mechanical equipment are principally contained in Appendices A and B of 10 CFR 50. The qualification methods defined in NUREG-0588 can also be applied to mechanical equipment.

To document the degree to which the environmental qualification program complies with the NRC environmental qualification requirements and criteria, the applicant provided equipment qualification information by letters dated March 1, October 19, and December 14, 1984, February 15, March 12 and 15, April 26, May 13, June 19, and July 19, 1985, to supplement the information in the FSAR Section 3.11.

The staff has reviewed the adequacy of the RBS environmental qualification program for electrical equipment important to safety as defined in 10 CFR 50.49 and the program for safety-related mechanical equipment. The scope of this

report includes an evaluation of (1) the completeness of the list of systems and equipment to be qualified, (2) the criteria they must meet, (3) the environments in which they must function, and (4) the qualification documentation for the equipment. It is limited to electrical equipment important to safety within the scope of 10 CFR 50.49 and safety-related mechanical equipment.

3.11.3 Staff Evaluation

The staff evaluation included an onsite examination of equipment, an audit of qualification documentation, and a review of the applicant's submittals for completeness and acceptability of systems and components, qualification methods, and accident environments. The criteria described in Section 3.11 of the NRC Standard Review Plan (NUREG-0800), Revision 2, in NUREG-0588 Category 1, and the requirements in 10 CFR 50.49 form the bases for the staff evaluation.

The staff performed an audit of the applicant's qualification documentation and installed electrical equipment on January 26, 27, and 28, 1985. The audit consisted of a review of 12 files containing information regarding equipment qualification. The staff's findings from the audit are discussed in Section 3.11.4.2 of this report.

3.11.3.1 Completeness of Equipment Important to Safety

10 CFR 50.49 identifies three categories of electrical equipment that must be qualified in accordance with the provisions of the rule.

(1) safety-related electrical equipment (equipment relied on to remain functional during and following design-basis events).

(2) nonsafety-related electrical equipment whose failure under the postulated environmental conditions could prevent satisfactory accomplishment of the safety functions by the safety-related equipment.

(3) certain post-accident monitoring equipment (R.G. 1.97, Category 1 and 2 post-accident monitoring equipment).