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December 9, 1983
RBG- 16535
File No. G9.5, G9.8.6.1

Mr. Harold R. Denton, Director
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commisson
Washington, D. C. 20555

Dear Mr. Denton:

River Bend Station Units 1 and 2
Docket Nos. 50-458/50-459

Enclosed are Gulf States Utilities Company's responses to Request for Additional Information identified by the Nuclear Regulatory Commission's Instrumentation and Control Systems Branch (ICSB) and endorsement of the Licensing Review Group-II issues 1-ICSB through 7-ICSB. Attachment 1 of this letter summarizes the Staff requests identified in a letter dated July 28, 1982. The following enclosures contain the actual written changes to the FSAR including all inserts, tables, and figures. These changes will be incorporated into the FSAR in the next amendment.

Sincerely,

J E Booker

J. E. Booker
Manager-Engineering
Nuclear Fuels & Licensing
River Bend Nuclear Group

JEB/~~WJR~~/ERG/JEP/kt

Enclosures

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<u>ATTACHMENT 1</u>

FSAR QUESTION	SUBJECT	FSAR REVISIONS
421.01	Remote Shutdown System	Enclosure 1
421.02	ESF Reset Controls (IEB 80-06)	Enclosure 2
421.03	Loss of I&C Power Bus (IEB 79-27)	Enclosure 3
421.04	Control System Failures from HELB	Enclosure 4
421.05	Control Systems Failures from Common Sensors	Enclosure 5
421.06	Branch Technical Positions	Enclosure 6
421.07	Bypass/Inoperative Indication (RG 1.47)	Enclosure 7
421.08	General Design Criteria	Amendment 9
421.09	Startup Monitoring System	Enclosure 8
421.10	Isolation Devices	Enclosure 9
421.11	NUREG 0737 Items	Amendment 9
421.12	Physical Separation (RG 1.75)	Enclosure 10
421.13	Common Instrument Taps	Amendment 9
421.14	Temperature Effects on Level Measurements (TMI Item II.F.2)	Enclosure 11
421.15	Mode Switch/Multiple Setpoints	Amendment 9
421.16	Electrical Protection Assemblies	Enclosure 12
421.17	Setpoint Methodology	Enclosure 13
421.18	Safety Signals Routed from Non-Seismic Areas	Enclosure 14
421.19	ATWS RPT	Amendment 9
421.20	Response Time Testing	Amendment 9
421.21	SDV Instrumentation	Enclosure 15
421.22	Interlocks Affecting Manual and Automatic Actuation of Safety Systems	Enclosure 16
421.23	Sensors Common to Both Automatic and Manual Start Circuitry	Enclosure 17
421.24	Non-Testable Components at Power	Enclosure 18
421.25	MS-PLCS	Amendment 9
421.26	HPCS High Pressure Interlock	Enclosure 19
421.27	Shared Systems	Amendment 9
421.28	Table 3.10A-1	Amendment 9
421.29	SLCS Heat Tracing	Amendment 9
421.30	Low-Low Set	Enclosure 20
421.31	High Pressure/Low Pressure Interlocks	Enclosure 21
421.32	SRV Relief Function	Amendment 9
421.33	Process Computer	Amendment 9
421.34	Design Completion	Amendment 9
421.35	Microprocessors, Multiplexers, and Computers	Enclosure 22
421.36	Separation Criteria (RG 1.97 Rev 2)	Amendment 9
421.37	Separation within Instrument Cabinets	Enclosure 23

The endorsement to LRG-II positions 1-ICSB through 7-ICSB is provided below. This table and the discussions provided in Enclosures 2, 3, 4, 5, 20, and 21 will be incorporated into the FSAR in a future amendment.

ITEM	TITLE	ENDORSED	FSAR DISCUSSION
1-ICSB	Failures in Vessel Level Sensing Lines Common to Control and Protective Systems	Yes	Q421.13
2-ICSB	Redundancy and Diversity of High/Low Pressure System Interlocks	Yes	Q421.31
3-ICSB	Potential for Two Low-Low Setpoint Valves to Open Due to a Single Failure	Yes	Q421.30
4-ICSB	Loss of Safety Function After Reset	Yes	Q421.02
5-ICSB	Control Systems Failures	Yes	Q421.05
6-ICSB	Procedures Following Bus Failure	Yes	Q421.03
7-ICSB	Harsh Environment for Electric Equipment Following High Energy Line Break	Yes	Q421.04

ENCLOSURE 1

QUESTION 421.001 (7.4)

Describe how the remote shutdown station design at River Bend complies with GDC 19 as interpreted in Section 7.4 of the SRP. Clarification of these requirements was provided in the "ICSB Position for Remote Shutdown Capability for River Bend" issued to W. Cahill, Jr. (GSU) from A. Schwencer (NRC) by letter dated May 17, 1982.

RESPONSE

~~The response to this request will be provided by September 1983.~~

The River Bend Station design has been revised to implement redundant Class 1E shutdown panels. See revised Section 7.4.1.4 for further description of the system.

before leaving the main control room. The capability of opening the output breakers of the RPS logic from outside the main control room can be used as a backup means to achieve initial reactor reactivity shutdown.

3. The main turbine pressure regulators may be controlling reactor pressure via the bypass valves. It is assumed that this turbine generator control panel function is also lost. Therefore, main steam isolation is assumed to occur at a specified low turbine inlet pressure and reactor pressure is relieved through the relief valves to the suppression pool.

4. The reactor feedwater system which is normally available is also assumed to be inoperable. Reactor vessel water inventory is provided by the RCIC system,1

The RSS is required only during times of main control room inaccessibility when normal plant operating conditions exist, i.e., no transients or accidents are occurring. For this reason, ~~the RSS function is not single failure-proof and~~ only the equipment which interfaces directly with safety-related equipment (RHR, RCIC, etc) is required to be of safety-related quality. INSERT

2. Remote Shutdown System Operation

Instrument location drawings and elementary diagrams are identified in Section 1.7.

Some of the existing systems used for normal reactor shutdown operation are also utilized in the remote shutdown capability to shut down the reactor from outside the main control room. The 2 remote shutdown ~~capability~~ panel is designed to control the required shutdown systems from outside the main control room irrespective of shorts, opens, or grounds in the control circuit in the main control room that may have resulted from an event causing an evacuation. The functions needed for remote shutdown control are provided with manual transfer switches which override controls from the main control room and transfer the controls to the remote shutdown panel. Remote shutdown control is not possible without actuation of the transfer ~~devices~~ 3. All necessary power supplies and control logic are also transferred. Operation of the transfer 3 ~~devices~~ causes an alarm in the main control room. Access to the remote shutdown panel is administratively and procedurally controlled. Controls and

1 or by the automatic initiation of the HPCS system.
2 Division I
3 switches

INSERT (for Pg. 7.4-7)

Transfer and control switches at the RSS panels are provided for equipment which is controlled during remote shutdown. The controls and indications at these panels are listed in the following sections. Functional redundancy is provided by the Division I and Division II panels which are located in different fire areas in the control building (El 98).

instrumentation for all system equipment (i.e., valves and pumps) necessary for proper system lineup and complete system control are located on the remote shutdown ~~panel~~ panels.

Manual activation of SRVs, along with ~~and~~ the initiation of RCIC system ① maintain reactor water inventory and bring the reactor to a hot shutdown condition after scram. During this phase of shutdown, the suppression pool is cooled by operating the RHR system in the suppression pool cooling mode. Reactor pressure is controlled and core decay and sensible heat are rejected to the suppression pool by relieving steam pressure through the relief valves.

Manual operation of the relief valves cools the reactor and reduces its pressure at a controlled rate until ② ~~reactor pressure becomes so low that the RCIC system is unable to sustain operation~~. The RHR system is ~~then~~ operated in the shutdown cooling mode using the RHR system heat exchanger to cool reactor water and bring the reactor to the cold ~~low pressure~~ shutdown condition.

a. Reactor Core Isolation Cooling (RCIC) System

The following RCIC system equipment/functions have transfer and control switches located on the Division I remote shutdown panel.

~~E51-F010~~ 1E51*MOVF010 - Motor-operated valve (pump suction from condensate storage)

~~E51-F013~~ 1E51*MOVF013 - Motor-operated valve (RCIC injection shutoff)

~~E51-F019~~ 1E51*MOVF019 - Motor-operated valve (minimum flow to suppression pool)

~~E51-F022~~ 1E51*MOVF022 - Motor-operated valve (test bypass to condensate storage)

~~E51-C004~~ 1E51*PC002C - Gland seal system air compressor

~~E51-F031~~ 1E51*MOVF031 - Motor-operated valve (pump suction from suppression pool)

~~E51-F045~~ 1E51*MOVF045 - Motor-operated valve (steam to turbine)

~~E51-F046~~ 1E51*MOVF046 - Motor-operated valve (lube oil cooling)

~~E51-F059~~ 1E51*MOVF059 - Motor-operated valve (test bypass to condensate storage)

① and/or the automatic initiation of the HPCS system,

② the cold shutdown condition is reached or alternative methods of heat removal are restored.

INSERT (for Pg. 7.4-7)

Transfer and control switches at the RSS panels are provided for equipment which is controlled during remote shutdown. The controls and indications at these panels are listed in the following sections. Functional redundancy is provided by the Division I and Division II panels which are located in different fire areas in the control building (El 98).

~~E12-F004A~~ - Motor-operated valve (RHR pump suction)
1E12*MOVF004A

~~E12-F006A~~ - Motor-operated valve (shutdown cooling)
1E12*MOVF006A

~~E12-F006B~~ - Motor-operated valve (shutdown cooling)
1E12*MOVF006B

~~E12-F008~~ - Motor-operated valve (outboard shutdown isolation)
1E12*MOVF008

~~E12-F009~~ - Motor-operated valve (inboard suction isolation)
1E12*MOVF009

~~E12-F011A~~ - Motor-operated valve (RHR heat exchanger flow to suppression pool)
1E12*MOVF011A

~~E12-F023~~ - Motor-operated valve (reactor head spray)
1E12*MOVF023

~~E12-F024A~~ - Motor-operated valve (RHR test line)
1E12*MOVF024A

~~E12-F026A~~ - Motor-operated valve (RHR heat exchanger flow to RCIC)
1E12*MOVF026A

~~E12-F027A~~ - Motor-operated valve (injection shutoff)
1E12*MOVF027A

~~E12-F037A~~ - Motor-operated valve (shutoff upper pool cooling)
1E12*MOVF037A

~~E12-F042A~~ - Motor-operated valve (RHR injection)
1E12*MOVF042A

~~E12-F047A~~ - Motor-operated valve (heat exchanger shell side inlet)
1E12*MOVF047A

~~E12-F048A~~ - Motor-operated valve (heat exchanger shell side bypass)
1E12*MOVF048A

~~E12-F040~~ - Motor-operated valve (discharge to radwaste)
1E12*MOVF040

~~E12-F052A~~ - Motor-operated valve (steam isolation)
1E12*MOVF052A

~~E12-F053A~~ - Motor-operated valve (RHR injection)
1E12*MOVF053A

~~E12-F064A~~ - Motor-operated valve (RHR pump minimum flow)
1E12*MOVF064A

~~E12-F068A~~ - Motor-operated valve (heat exchanger water discharge valve).
1E12*MOVF068A

INSERT A

See Fig. 5.4-12.

The following RHR instrumentation is located on the Division I remote shutdown panel:

INSERT (for Pg. 7.4-10)

The following RHR system equipment/functions have transfer and control switches located at the Division II remote shutdown panel:

1E12*PC002B - RHR Pump

1E12*MOVFR04B - Motor-operated valve (CRHR pump suction - suppression pools)

1E12*MOVF064B - Motor-operated valve (RHR pump minimum flow bypass)

1E12*MOVF047B - Motor-operated valve (heat exchanger inlet)

1E12*MOVF003B - Motor-operated valve (heat exchanger outlet)

1E12*MOVF027B - Motor-operated valve (RHR B outboard isolation)

1E12*MOVF042B - Motor-operated valve (RHR B injection)

1E12*MOVF024B - Motor-operated valve (RHR test return)

1E12*MOVF053B - Motor-operated valve (shutdown cooling injection)

1E12*MOVF048B - Motor-operated valve (heat exchanger bypass)

1E12*MOVF011B - Motor-operated valve (RHR heat exchanger flow to suppression pool)

1E12*MOVF052B - Motor-operated valve (steam line isolation)

1E12*MOVF037B - Motor-operated valve (shutdown upper pool cooling)

1E12*PC002C - RHR pump

1E12*MOVF105 - Motor-operated valve (CRHR pump suction - suppression pool)

1E12*MOVF064C - Motor-operated valve (RHR pump minimum flow bypass)

1E12*MOVF042C - Motor-operated valve (RHR C injection)

~~C61-R005~~ - RHR flow indicator for loop A
1C61*FIR005

Valve position status indication and pump status indication.

INSERT A

c. Nuclear Boiler System

The following functions have transfer and control switches located at the ② remote shutdown ~~panel:~~ panels

~~B21-F051C~~ - Air-operated SRV (non-ADS)
1B21*RVF051C

~~B21-F051G~~ - Air-operated SRV (non-ADS)
1B21*RVF051G

~~B21-F051D~~ - Air-operated SRV (non-ADS)
1B21*RVF051D

The following nuclear boiler instrumentation is provided on the ① remote shutdown panel:

~~C61-R010~~ - Reactor level indicator
1C61*LIR010

~~C61-R011~~ - Reactor pressure indicator
1C61*PIR911

Valve position status indicators.

INSERT B

See Fig. 7.3-2.

d. Standby Service Water System

The following SSW system equipment/functions have transfer and control switches located at the ① remote shutdown panel:

~~1SWP*MOV505A - Motor-operated valve (header A isolation)~~

1SWP*P2A - SSW pump.
1SWP*P2C - SSW pump.

INSERT C

See Fig. 7.3-11.

The following SSW system instrumentation is provided on the ① remote shutdown ~~panel/~~ panels:

~~1SWP*FI64 - Flow indicator (RHR heat exchanger A)~~
1SWP*FI64A and FI64B - Flow indicators (RHR heat exchangers A and B)

Valve position and pump status indicators.

e. Containment Atmosphere Monitoring System

The following containment atmosphere monitoring system instrumentation is provided on the ① remote shutdown panel:

① Division I
② Division I and Division II

INSERT A (for Pg. 7.4-11)

The following RHR instrumentation is located on the Divison II remote shutdown panel:

1RHS*FI15B - RHR B pump flow

1RHS*FI15C - RHR C pump flow

INSERT B (for Pg. 7.4-11)

The following nuclear boiler instrumentation is provided on the Division II remote shutdown panel:

1ISC*PI101 - Reactor vessel pressure

1RHS*LI119 - Reactor vessel level

INSERT C (for Pg. 7.4-11)

The following SSW system equipment/functions have transfer and control switches located at the Division II remote shutdown panel:

1SWP*P2B - SSW pump

1SWP*P2D - SSW pump

1SWP*MOV96B - Motor-operated valve (isolate normal SW supply)

1SWP*MOV55B - Motor-operated vavle (cooling tower inlet)

1E12*MOVR068B - Motor-operated valve (SW outlet from RHR heat exchanger)

1CMS*~~PR102~~ TR103 - Recorder (drywell pressure/temperature ①

~~1CMS*LR101 - Recorder (suppression pool level/ temperature)~~

INSERT

7.4.1.5 Design Basis Information

The safe shutdown systems are designed to provide timely protection against the onset and consequences of conditions that threaten the integrity of the fuel barrier and the RCPB. Chapter 15 identifies and evaluates events that jeopardize the fuel barrier and RCPB. The methods of assessing barrier damage and radioactive material releases, along with the methods by which abnormal events are identified, are presented in that chapter.

1. Variables Monitored to Provide Protective Actions

The following variables are monitored in order to provide protective actions to the safe shutdown systems:

a. RCIC - Reactor vessel low water level (trip level 2)

All other safe shutdown systems are initiated by operator actions.

The plant conditions which require protective action involving safe shutdown are described in Chapter 15 and Appendix 15A.

2. Location and Minimum Number of Sensors

See the Technical Specifications for the minimum number of sensors required to monitor safety-related variables. There are no sensors in the safe shutdown systems which have a spatial dependence.

3. Prudent Operational Limits

Prudent operational limits for each safety-related variable trip setting are selected with sufficient margin so that a spurious safe shutdown system initiation is avoided. It is then verified by analysis that the release of radioactive materials, following postulated gross failures of the fuel or the nuclear system process barrier, is kept within acceptable bounds.

① and suppression pool level/temperature)

INSERT (for Pg. 7.4-12)

The following containment atmosphere monitoring system instrumentation is provided on the Division II remote shutdown panel:

1CMS*TI40B and 1CMS*TI40D - Suppression pool temperature

1CMS*LIX23B - Suppression pool level

1CMS*PI2B - Drywell pressure

1CMS*TI41B and 1CMS*TI41D - Drywell temperature

ENCLOSURE 2

QUESTION 421.002 (7.3)

Provide a detailed response to the concerns addressed by IE Bulletin 80-06 (Engineered Safety Feature (ESF) Reset Controls) issued to operating reactors March 13, 1980. For all safety-related equipment which does not remain in its emergency mode following an ESF reset, provide adequate justification for the change of state of each piece of equipment or proposed corrective actions to prevent such changes (e.g., equipment returning to its normal operational status). If the LRG II position paper regarding IE Bulletin 80-06 is determined to be applicable to River Bend, this fact must be documented. A response to IE Bulletin 80-06 was requested by letter dated April 16, 1981 (Request for Additional Information from OL Applicants Regarding Four Instrumentation and Control Systems Concerns) from R. Tedesco (NRC) to E. L. Draper (GSU).

RESPONSE

The response to this request ~~will be provided by September 1983~~. is provided in revised Section 7.3.2.1. This response is consistent with LRG-II Item 4-ICSB.

2. Functional control diagrams (FCD) or logic diagrams (LSK)

have been provided or referenced for the ESF systems in this section.

ESF systems elementary diagrams are listed in Section 1.7.

Equipment arrangement drawings are provided in Section 1.2.

Functional and architectural design differences between the PSAR and FSAR are listed in Table 1.3-8.

7.3.2 Analysis

7.3.2.1 ESF Systems

Chapters 15 and 6 evaluate the individual and combined capabilities of the ESF systems.

The ESF systems are designed in such a way that a loss of instrument air, loss of cooling water to vital equipment, a plant load rejection, or a turbine trip does not prevent the completion of the safety function.

1 A system-level/qualitative type plant FMEA, the Nuclear Safety Operational Analysis (NSOA), is presented in Appendix 15A. In addition, failure modes and effects analyses for balance-of-plant (BOP) ESF instrumentation and control systems are contained in the FMEA document.

INSERT →

7.3.2.1.1 Conformance to Title 10 Code of Federal Regulations, Part 50 (10CFR50) Appendix A - General Design Criteria (GDC)

The conformance discussions provided in Section 3.1 for the GDC apply to the ESF Systems, as identified in Table 7.1-3.

7.3.2.1.2 Conformance to IEEE Standards

The following is a discussion of conformance to those IEEE standards which apply specifically to the ESF systems. Refer to Section 7.1.2.3 for a generic discussion of IEEE standards which apply to the ESF systems, as identified in Table 7.1-3.

1. IEEE 279-1971

a. General Functional Requirement (IEEE 279-1971, Paragraph 4.1)

INSERT (for Pg. 7.3-40)

All plant systems having ESF functions or providing support for ESF functions were reviewed in the context of IE Bulletin 80-06. It has been verified that except as discussed below, (1) protective action is completed once initiated; (2) all safety-related equipment remains in its emergency mode upon reset of an ESF actuation signal; and (3) return of a system to nonsafety-feature operation requires subsequent deliberate operator action.

1a. HPCS Diesel Generator

A system level reset of the ESF actuation signal does not shut down the diesel generator. However, a system level reset does restore all of the protective trips provided for diesel generator protection (i.e., high jacket water temperature, low lubrication oil pressure, anti-monitoring (reverse power), loss of excitation, overcurrent) which are blocked during an abnormal condition. If any of these protective trips are present at the time of system level reset, the diesel generator trips and a lockout occurs.

In the emergency mode, the HPCS diesel generator is a source of on-site power. During emergencies, which includes a LOCA, most of the protective trip functions are blocked so that the diesel operates as long as possible, regardless of the damage that it may incur. Upon conclusion of the emergency, all protective functions are restored as soon as the LOCA signal is manually reset. This restoration of protective functions is provided so that the diesel does not suffer any more damage than necessary. The trips are not reinstated until the LOCA signal is reset. Since this signal must be manually reset, the trips are, in effect, manually reinstated. Thus, after the LOCA, the diesel continues to run with all trips functioning normally.

1b. Standby Diesel Generators

The standby diesel generators (1EGS*EG1A and 1EGS*EG1B) operate in a manner similar to the HPCS diesel. Upon reset of the ESF actuation signal, the generator protective trips are automatically restored, whereas the engine protective trips must be manually restored. Refer to Sections 8.3.1.3.6.1.2 and 8.3.1.1.4.1 for a description of the standby diesel generator protective interlocks.

It is the River Bend Station position that this method of operation for the HPCS and standby diesel generator meets the intent of IE Bulletin 80-06 and no modifications are planned.

2. Automatic Depressurization System

A reset de-energizes the ADS solenoids, thus returning the air operated ADS valves to normal closed condition.

The design of the ADS includes a dedicated reset button in each of the two divisions. Pushing both buttons causes all ADS valves to close interrupting ADS action for 120 seconds. The reset push buttons are provided for manually preventing or limiting inadvertent actuation of the ADS. These are the only ADS shutoff switches available to the operator.

It is the River Bend Station position that this design is consistent with IEEE Standards and no change is considered appropriate in response to IE Bulletin 80-06.

ENCLOSURE 3

QUESTION 421.003 (7.5)

If reactor controls and vital instruments derive power from common electrical distribution systems, the failure of such electrical distribution systems may result in an event requiring operator action concurrent with failure of important instrumentation upon which these operator actions should be based. IE Bulletin 79-27 addresses several concerns related to the above subject. You are requested to provide information and a discussion based on each IE Bulletin 79-27 concern. Also, you are to:

1) Confirm that all a.c. and d.c. instrument buses that could affect the ability to achieve a cold shutdown condition were reviewed. Identify these buses.

2) Confirm that all instrumentation and controls required by emergency shutdown procedures were considered in the review. Identify these instruments and controls at the system level of detail.

3) Confirm that clear, simple, unambiguous annunciation of loss of power is provided in the control room for each bus addressed in Item 1 above. Identify any exceptions.

4) Confirm that the effect of loss of power to each load on each bus identified in Item 1 above, including ability to reach cold shutdown, was considered in the review.

5) Confirm that the re-review of IE Circular No. 79-02 which is required by Action Item 3 of Bulletin 79-27 was extended to include both Class 1E and non-Class 1E inverter supplied instrument or control buses. Identify these buses or confirm that they are included in the listing required by Item 1, above.

This item was also addressed in the April 16, 1981, letter from R. Tedesco to E. L. Draper (See Question 421.002).

RESPONSE

Items 1, 3, 4: A review of the buses supplying power to instrumentation and control systems which could affect the ability to achieve a cold shutdown condition ~~is being~~ has been performed for River Bend Station in accordance with IE

Bulletin 79-27, ① ~~This review will be completed by the third quarter of 1983~~.

INSERT A

Item 2: River Bend Station emergency ~~shutdown~~ ③ procedures are not yet complete. Prior to receipt of an operating license, GSU will confirm that all instrumentation and controls required by emergency shutdown procedures were considered in the review and will identify these instruments and controls at the system level.

Item 5: The review of IE Circular 79-02 ~~will be~~ ② extended to include both Class 1E and non-Class 1E power supply inverters. ~~The results of this review will be included in the response to Items 1, 3, and 4 above~~.

INSERT B

①, as follows:
② has been
③ operating

INSERT A (for Pg. Q&R 7.5-2)

A. All instrument and control systems utilized to achieve a cold shutdown by normal and emergency means, as described in FSAR Section 7.4 and Figure 7.4-3, were considered.

B. All AC and DC buses supplying power to these sytems were reviewed to determine the effects of loss of power to each bus and its associated devices on the ability to achieve cold shutdown.

C. Alarms and/or indications provided in the main control room to alert the operator to the loss of power to these buses were identified.

D. Control room indicators were reviewed to determine if any fail as is or at midscale such that erroneous information is provided to the operator.

The results of this review indicate the following:

A. For each AC and DC bus supplying power to instrument and control systems utilized to achieve a cold shutdown by normal or emergency means:

   (i) Cold shutdown can be achieved assuming loss of power to the bus.

   (ii) Clear, unambiguous annunciation is provided in the main control room to alert the operator of an undervoltage condition on the bus. Upon receipt of an undervoltage alarm while the plant is in the normal shutdown path, the operator can switch to an alternate shutdown path as governed by the emergency operating procedures.

B. No main control room indicators for the systems identified above fail as is. This, in accordance with IEEE Standard 279-1971 paragraph 4.20, prevents erroneous information from being presented to the operator.

INSERT B (for Pg. Q&R 7.2-2)

There are two safety-related uninterruptible power supply systems (1ENB*INV01A and 1ENB*INV01B) and five nonsafety-related (UPS) systems (1IHS-INV01, 1BYS-INV01A, 1BYS-INV01B, 1BYS-INV02, and 1BYS-INV04) at River Bend Station. All seven UPS systems are identical in design. This design, as discussed in FSAR Section 8.3.1.1.3.7, differs from the subject of IE Circular No. 79-02, and therefore does not fail in a similar manner. In addition, an eighth power supply inverter has recently been added to the design. This non-safety related (UPS) system (1BYS-INV06), located in the Technical Support Center, furnishes power to DRMS, ERIS, and other support service loads. The additional non-safety related (UPS) system is currently being evaluated in context with IE Bulletin No. 79-27.

ENCLOSURE 4

QUESTION 421.004 (7.7)

If control systems are exposed to the environment resulting from the rupture of reactor coolant lines, steam lines or feedwater lines, the control systems may malfunction in a manner which would cause consequences to be more severe than assumed in safety analyses. I&E Information Notice 79-22 discusses certain non-safety grade or control equipment, which if subjected to the adverse environment of a high energy line break, could impact the safety analyses and the adequacy of the protection functions performed by the safety grade systems.

The staff is concerned that a similar potential may exist at light water facilities now under construction. You are, therefore, requested to perform a review per the I&E Information Notice 79-22 concern to determine what, if any, design changes or operator actions would be necessary to assure that high energy line breaks will not cause control system failures to complicate the event beyond the FSAR analysis. Provide the results of your review including all identified problems and the manner in which you have resolved them.

The specific "scenarios" discussed in the above referenced Information Notice are to be considered as examples of the kinds of interactions which might occur. Your review should consider analogous interactions as relevant to the BWR design.

This item was addressed in the April 16, 1981 letter from R. Tedesco to E. L. Draper.

RESPONSE

~~A review of River Bend Station per IE Information Notice 79-22 will be performed. The results of this review will be available in 1984.~~

INSERT

INSERT (for Pg. Q&R 7.7-1)

A review of River Bend Station control systems will be performed in accordance with IE Information Notice 79-22. The results of this review will be available by the end of 1984, and will be conducted according to the following methodology:

1. From a complete list of all plant systems, identify all non-safety control grade systems which have the potential to impact reactor pressure, reactor water level, or reactor power.

2. Assume that any components in these identified systems, if damaged, would cause controlled equipment to operate in its worst failure mode.

3. Divide buildings into definable zones, using walls, floors, etc., as zone boundaries, and determine which of these areas contain high energy piping and the identified non-safety systems.

4. In performing the analysis, the following criteria are utilized:

    a. High energy lines are those whose operating temperature is greater than 200 F or those whose maximum operating pressure is greater than 275 PSIG.

    b. Assume one break at a time, occurring at terminal ends, intermediate pipe fittings, or weld attachments.

    c. Pipe whip incapacitates any control system within its arc of motion.

    d. Jet impingement incapacitates any control system components within a calculated jet length.

    e. Evaluate effects due to humidity, pressure, and temperature on equipment not incapacitated by pipe whip or jet impingement.

    f. Determine that the redundancy of safety related systems is not defeated as a result of an HELB.

5. Determine the resultant effects by determining the "worst case" effect of a simultaneous HELB and control systems component failure, after analyzing all possibilities.

6. Choose two or more such "worst case" events and assume a "worst case" additional failure in a safety-related system.

7. Compare these postulated scenarios with the events analyzed in FSAR Chapter 15 and determine if additional analysis is needed to determine whether or not these scenarios are bounded by the events in FSAR Chapter 15.

8. Identify significant (unbounded) events, perform required additional analysis and indicate required corrective action.

ENCLOSURE 5

QUESTION 421.005 (7.7)

If two or more control systems receive power or sensor information from common power sources or common sensors (including common headers or impulse lines), failures of these power sources or sensors or rupture/plugging of a common header or impulse line could result in transients or accidents more severe than considered in plant safety analyses.

A number of concerns have been expressed regarding the adequacy of safety systems in mitigation of the kinds of control system failures that could actually occur at nuclear plants, as opposed to those analyzed in FSAR Chapter 15 safety analyses. Although the Chapter 15 analyses are based on conservative assumptions regarding failures of single control systems, systematic reviews have not been reported to demonstrate that multiple control system failures beyond the Chapter 15 analyses could not occur because of single events. Among the types of events that could initiate such multiple failures, the most significant are in our judgment those resulting from failure or malfunction of power supplies or sensors common to two or more control systems.

To provide assurance that the design basis event analyses adequately bound multiple control system failures you are requested to provide the following information:

1) Identify those control systems whose failure or malfunctions could seriously impact plant safety.

2) Indicate which, if any, of the control systems identified in (1) receive power from common power sources. The power sources considered should include all power sources whose failure or malfunction could lead to failure or malfunction or more than one control system and should extend to the effects of cascading power losses due to the failure of higher level distribution panels and load centers.

3) Indicate which, if any, of the control systems identified in (1) receive input signals from common sensors. The sensors considered should include, but should not necessarily be limited to, common hydraulic headers or impulse lines feeding pressure, temperature, level or other signals to two or more control systems.

4) Provide justification that any simultaneous malfunctions of the control systems identified in (2) and (3) resulting from failures or malfunctions of the applicable common power source or sensor are bounded by the analyses in Chapter 15 and would not require action or response beyond the capability of operators or safety systems.

This item was addressed in the April 16, 1981, letter from R. Tedesco (NRC) to E. L. Draper (GSU).

RESPONSE

~~The response to this request will be provided by the third quarter of 1983.~~

INSERT

INSERT (for Pg. Q&R 7.7-3)

A review of River Bend Station control systems is being performed. The results of this review will be submitted by the end of April 1984. The methodology used for this study is similar to that of other BWRs, and is consistent with the guidance provided by the NRC Staff. The methodology used is as follows:

I. Common Power Source Failure Analysis (Due to loss of power supply, short circuit, open circuit)

1. Define control grade systems relevant to analysis

A. Establish a list of all plant systems. The list of all plant systems identified for River Bend Station is provided below:

Condenser Air Removal
Reactor Plant Component Cooling Water
Turbine Plant Component Cooling Water
Condensate
Bearing Cooling Water
Circulating Water
Turbine Building Equipment Drains
Moisture Separator Vents and Drains
Moisture Separator RHTR Vents and Drains
Turbine Building Miscellaneous Drains
Extraction Steam
FDW Pump 4 Drive Lube Oil
FDW Pump Recirculation
Feedwater
Generator Leads Cooling
Generator Stator Cooling Water
Generator Hydrogen and CO2
High-Pressure FDW Heater Drain
Low-Pressure FDW Heater Drain
Service Air
Instrument Air
Main Steam
Offgas
Reactor Recirculation
Control Rod Drive
FDW Heater Relief Drains and Vents
Reactor Plant Sampling
Turbine Plant Sampling
Radwaste Building Sampling
Service Water
Turbine Trips
Turbine Generator E.H. Fluid System
Turbine Generator Gland Seal and Exhaust
Turbine Generator Lube Oil
Unit Runback
Turbine Generator Exhaust Hood Spray
Reactor Water Cleanup
Feedwater Control
Nuclear Boiler Process Instrumentation

Neutron Monitoring (Power Range)
Steam Bypass and Regulation
Leak Detection
Process Radiation Monitoring
Cold Reheat
Hot Reheat
Drywell Cooling
Reactor Building Equipment Drains
Main Generator Excitation
Generator Seal Oil
Generator Trips

B. Define criteria to eliminate systems from analysis. Any non-safety control grade system which effects the critical reactor parameters (water level, pressure, power) is included in the detailed analysis. The elimination criteria and basis identified for River Bend Station are provided below:

Elimination Criteria	Basis
N1	Non-Electrical components (i.e., mechanical and structural); however, associated functions that are electrically controlled or controlling (including signal input to electrical systems) may be relevant to the analysis. N1 examples are piping, tanks, turbines, etc.
N2	Instrumentation with no direct or indirect controlling function or passive input (such as a permissive) into control logic. Instrumentation and other dedicated inputs to the process computer, as well as the computer itself, may probably be excluded. Operator actions as a result of indications are not considered control functions for the control systems failure analysis.
N3	Control systems and controlled components (pumps, valves) with reactor operation/parameters. Examples are communications, most unit heaters and controls, lighting controls, ventilation control systems for exterior buildings, machine shop equipment, refueling or maintenance equipment controls, etc.
N4	Control systems and controlled components (pumps, valves) that do not interact or interface with reactor parameters (water level, pressure or reactivity) either directly or indirectly.

N5 Systems or components which cannot affect reactor parameters within 10 minutes of the loss of any power bus or combination thereof.

N6 Systems which are not used during normal power operation. For example, eliminate start-up, shutdown or refueling systems not used during normal operation.

N7 Electrical components involved in distribution, transformation or interruption of power; however, controls for these components may need to be considered if loss of such control power may lead to failure of other electrical buses.

N8 Safety Systems, except for their response to conditions brought about by control systems failures. Example: a level 3 scram is assumed for a loss of feedwater event.

C. Evaluate the system list against the elimination criteria. Eliminate all systems with no relevance to the analysis. Retain any system which is questionable for further analysis.

2. Review each relevant system at the component level

Examine the loss of power to each instrument and control component. Document the effects of the loss of the component a) on the system's ability to perform its intended fuctions, b) on the performance of other systems, c) on the critical reactor parameters. Document information on formatted "Load Sheets".

3. Perform combined effects analyses

A. Evaluate the "Load Sheets" at the lowest common bus level. Evaluate the combined effects on all control systems affected, and on the critical reactor parameters, as a result of the loss of each single bus.

B. Generate bus trees. The trees represent the bus hierarchy and cascading configuration of all power busses which feed components of control systems not eliminated.

C. Evaluate each "higher" level of common power busses documenting the effects of cascading bus failures on all systems affected and on the critical reactor parameters.

4. Perform Chapter 15 comparison

A. Postulate transient events as a result of the combined effects analyses. Compare resulting transients to those analyzed in FSAR Chapter 15. Perform any new transient calculations/analyses required to ensure events are bounded.

B. Publish any hardware or procedural change recommendations which result from the above.

II. Common Sensor Failure Analysis

1. Define control systems relevant to the analysis

   Use final system list developed for the common power source failure analysis.

2. Identify all instrument sensor lines utilized by two or more systems identified in 1 above.

3. Analyze the effects on each instrument (primary effect) for each of three cases:

   A. 100% plug (or pinched closed) in the reference leg or variable leg.

   B. Guillotine break in the reference leg or the variable leg.

   C. Document the primary effect for each instrument in each case.

4. Document the effects of sensing an incorrect pressure or water level on trips, permissives, interlocks, scram signals, etc., which are actuated or rendered inoperative due to the erroneous signal from the instrument being analyzed.

5. Document the combined, interactive effects of all instrument failures on a common sensing line for each of the three cases. Investigate the interaction between affected systems and determine the combined effect on the critical reactor parameters.

6. Compare consequences of combined effects with FSAR, Chapter 15. Analyze any additional transient events not covered by Chapter 15.

7. Modify/Augment Chapter 15 as necessary.

ENCLOSURE 6

QUESTION 421.006 (7.1)

Table 7.1-3 of the FSAR contains no references to the Branch Technical Positions listed in Table 7.1 of the Standard Review Plan. The FSAR should identify and justify any exceptions taken to these Branch Technical Positions.

RESPONSE

The response to this request is provided in revised Table 7.1-3. Branch Technical Positions ICSB-4, 12, 13, 14, 16, ~~and~~ 20 are not applicable to River Bend Station.

, and 26

TABLE 7.1-3 (CONT)

SAFETY SYSTEMS / CODES AND STANDARDS	REACTOR PROTECTION (TRIP) SYSTEM	EMERGENCY CORE COOLING SYSTEM	CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM	MAIN STEAM POSITIVE LEAKAGE CONTROL SYSTEM	STANDBY GAS TREATMENT SYSTEM	COMBUSTIBLE GAS CONTROL SYSTEM	REACTOR PLANT VENTILATION SYSTEM	RHR SYSTEM-SUPPRESSION POOL COOLING MODE	STANDBY SERVICE WATER SYSTEM	CONTROL BUILDING AIR CONDITIONING SYSTEM	CONTROL BUILDING CHILLED WATER SYSTEM	STANDBY POWER SUPPORT SYSTEMS	DIESEL GENERATOR BUILDING VENTILATION SYSTEM	SSW PUMP HOUSE VENTILATION SYSTEM	AUXILIARY BUILDING VENTILATION SYSTEM	FUEL BUILDING VENTILATION	REACTOR CORE ISOLATION COOLING SYSTEM	RHR SYSTEM-REACTOR SHUTDOWN COOLING MODE	STANDBY LIQUID CONTROL SYSTEM	REMOTE SHUTDOWN SYSTEM	SAFETY-RELATED DISPLAY INSTRUMENTATION	RECIRCULATION PUMP TRIP	LEAK DETECTION SYSTEM	NEUTRON MONITORING SYSTEM	RADIATION MONITORING SYSTEM	FUEL POOL COOLING SYSTEM	PENETRATION VALVE LEAKAGE CONTROL SYSTEM	ROD PATTERN CONTROL SYSTEM
BTP ICSB 3		X		X														X									~~X~~	
BTP ICSB 21		X	X		X		X	X	X	X		X	X		X	X	X	X							X			
BTP ICSB 22	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X											X	X
~~BTP ICSB 26~~	~~X~~																											

Amendment 9 July 1983

ENCLOSURE 7

QUESTION 421.007 (7.1.2.4)(7.5)

In the discussion on conformance to Regulatory Guide (RG) 1.47, FSAR, Section 7.1.2.4, the statement is made that system level annunciation upon actuation of bypass or test switches is not fully implemented into the design. Identify all safety-related systems in which this feature is not implemented in the design and discuss plans to bring these systems into conformance with RG 1.47. In addition, determine whether the bypass and inoperable status indication system complies with position B2 of ICSB Branch Technical Position 21, discuss the design philosophy used in the selection of equipment/systems to be monitored, and provide a complete list of system automatic and manual bypasses within the BOP and NSSS scope of supply as it pertains to the recommendations of R.G. 1.47.

The design philosophy should describe as a minimum the criteria to be employed in the display of inter-relationships and dependencies on equipment/systems and should verify that the bypassing or deliberately induced inoperabilty of any auxiliary or support system will automatically indicate all safety systems affected.

RESPONSE

~~The response to this request will be provided by September 1983.~~

The response to this request is provided in revised Section 7.1.2.4, Item 4.

Branch Technical Position ICSB 21, Position B2, relates to shared systems. This is addressed in the response to Question 421.027.

4. Conformance to Regulatory Guide 1.47

① /inoperative　　for automatic safety systems

The system of bypass ① indication is designed to satisfy the requirements of IEEE 279-1971, Paragraph 4.13 and Regulatory Guide 1.47. The design of the bypass ① indication system allows testing during normal operation, and is used to supplement administrative procedures by providing indication of automatic safety system status.

The bypass ① indication system is designed and installed in a manner which precludes the possibility of adverse effects on the plant safety systems. Those portions of the ~~bypass indication~~ system which when faulted could reduce the independence between redundant safety systems are electrically isolated from the protection circuits.

Typically, the following bypasses or inoperabilities cause actuation of system level annunciation for the affected system:

1. Pump motor breaker not in operate position
2. Loss of pump motor control power
3. Loss of motor-operated valve control power/motive power
4. Logic power failure
5. Logic in test

~~6. System lineup improper~~

6 ~~7.~~ Bypass or test switches actuated. ~~(This has not been fully implemented into design.)~~

REPLACE WITH INSERT

~~Auxiliary supporting system inoperability or bypass resulting in the loss of other safety-related systems causes actuation of system level annuciators for the auxiliary supporting system as well as the safety-related system affected. Fig. 7.1-1 shows the logic which is used to implement the requirements of Regulatory Guide 1.47 into the design of the plant. The interlocking of safety system indicators and the addition of bypass switches for manual initiation of system level inoperative indicators will be incorporated into the design prior to fuel delivery.~~

INSERT (for Pg. 7.1-10)

Automatic indication and annunciation is provided in the main control room to indicate that a system or part of a system is inoperable or bypassed. Bypass/inoperative indication is provided for those automatic safety systems indicated in Table 7.1-3 under Regulatory Guide 1.47. In addition, bypass/inoperative indication is provided for the following manually actuated systems:

1. Combustible gas control system

2. Standby liquid control system

3. Penetration valve leakage control system.

Details of the system inputs are provided in the logic diagrams provided in Sections 7.3, 7.4, 7.5, and 7.6, and in the discussion on diesel generator system protection and surveillance in Section 8.3.1.1.4

Bypasses of certain infrequently used pieces of equipment, such as manual locked-open valves, are not automatically annunicated in the main control room. However, capability for manual activation of each system level bypass/inoperative status indicator is provided by means of handswitches in the main control room for those systems that have these infrequently used bypasses.

Operation of manual valves, use of manual disconnects, or other operations occurring once a year or less frequently which could impair plant safety system performance, are controlled by administrative procedures and followed by system testing when such infrequent operations are completed. RBS administrative procedures contain shift turnover instructions which provide for a positive assessment of plant conditions and system status. These procedures minimize the probability of system bypasses existing undisclosed between periodic functional tests.

A summary of bypass and inoperable indication is provided in Table 7.1-4 with reference to FSAR logic diagrams. Cascading logic indication is not provided when support systems are normally in continuous operation or are manually actuated in accordance with operating in emergency procedures. In these case, the operator has adequate indication of proper support system operation and separate bypass and inoperable indication is not required.

TABLE 7.1-3 (CONT)

CODES AND STANDARDS \ SAFETY SYSTEMS	REACTOR PROTECTION (TRIP) SYSTEM	EMERGENCY CORE COOLING SYSTEM	CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM	MAIN STEAM-POSITIVE LEAKAGE CONTROL SYSTEM	STANDBY GAS TREATMENT SYSTEM	COMBUSTIBLE GAS CONTROL SYSTEM	REACTOR PLANT VENTILATION SYSTEM	RHR SYSTEM-SUPPRESSION POOL COOLING MODE	STANDBY SERVICE WATER SYSTEM	CONTROL BUILDING AIR CONDITIONING SYSTEM	CONTROL BUILDING CHILLED WATER SYSTEM	STANDBY POWER SUPPORT SYSTEMS	DIESEL GENERATOR BUILDING VENTILATION SYSTEM	SSW PUMP HOUSE VENTILATION SYSTEM	AUXILIARY BUILDING VENTILATION SYSTEM	FUEL BUILDING VENTILATION SYSTEM	REACTOR CORE ISOLATION COOLING SYSTEM	RHR SYSTEM-REACTOR SHUTDOWN COOLING MODE	STANDBY LIQUID CONTROL SYSTEM	REMOTE SHUTDOWN SYSTEM	SAFETY-RELATED DISPLAY INSTRUMENTATION	RECIRCULATION PUMP TRIP	LEAK DETECTION SYSTEM	NEUTRON MONITORING SYSTEM	RADIATION MONITORING SYSTEM	FUEL POOL COOLING SYSTEM	PENETRATION VALVE LEAKAGE CONTROL SYSTEM	ROD PATTERN CONTROL SYSTEM
R.G.1.29 REV.3	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
R.G.1.30 REV.0	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
R.G.1.40 REV.0							X																					
R.G.1.45 REV.0																							X					
R.G.1.47 REV.0	X	X	X	~~X~~	X	~~X~~	X	X	X	X	X	X	X	X	X	X	X	X	~~X~~	~~X~~		~~X~~	~~X~~	~~X~~	X	X	~~X~~	
R.G.1.53 REV.0	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X		X	X	X	X	X	X	X
R.G.1.62 REV.0	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X			X				X	X	
R.G.1.63 REV.2	X	X	X			X	X	X	X								X	X			X	X	X	X	X			X
R.G.1.68 REV.2	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
R.G.1.70 REV.3	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
R.G.1.73 REV.0		X	X		X	X			X								X									X		
R.G.1.75 REV.2	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
R.G.1.89 REV.0	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
R.G.1.96 REV.1				X																								
R.G.1.97 REV.2		X	X	X	X	X	X	X	X						X	X	X	X	X		X			X	X		X	
R.G.1.100 REV.1	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
R.G.1.105 REV.1	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X		X	X	X	X	X	X	X	X
R.G.1.118 REV.2	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X

Table 7.1-4

Summary of Bypass/Inoperable Annunciation

System	Logic Diagram FSAR Fig. No.	R.G. 1.47 POSITION COMPLIANCE C.1	C.2	C.3	C.4
Reactor Protection (Trip) Systems	7.3-1	Note #3	Note #3	Yes	Yes
Emergency Core Cooling System					
High Pressure Core Spray System (HPCS)	7.3-1	Yes	Note #1	Yes	Yes
Automatic Depressurization System (ADS)	7.3-2	Yes	Yes	Yes	Yes
Low Pressure Core Spray System (LPCS)	7.3-3	Yes	Yes	Yes	Yes
Residual Heat Removal System (RHR)	7.3-4	Yes	Yes	Yes	Yes
Containment and Reactor Vessel Isolation Control System					
Nuclear Steam Supply Shutoff System (NSSSS)	7.3-2	Yes	Note #2	Yes	Yes
BOP LOCA Initiation System (ISC)	7.3-24	Yes	Yes	Yes	Note #7
Standby Gas Treatment System (GTS)	7.3-7	Yes	Yes	Yes	Yes
Standby Service Water System (SWP)	7.3-11	Yes	Yes	Yes	Yes
Standby Power Support Systems	7.3-23	Yes	Yes	Yes	Yes
Reactor Core Isolation Cooling System (RCIC)	7.4-1	Yes	Yes	Yes	Yes

Notes

1. The Standby Service Water (SWP) System is a support system for the HPCS diesel generator during a loss of normal service water coincident with a LOCA or loss of offsite power (LOOP) event which would start the HPCS diesel generator. Loss of the SWP system is not cascaded into an HPCS inoperative/bypassed alarm because the incidence rate of a total loss of offsite power coincident with a failure of both trains of SWP to render HPCS inoperative is deemed sufficiently low to meet the regulatory guide position for not requiring same.

2. ESF control power failures are not annunciated at the NSSSS system level annunciation because the failure would cause the safety function to be performed as the system is fail-safe.

3. A failure of the Reactor Protection System (RPS) or its supporting systems will cause the safety function (reactor scram) to be performed. Hence, no system level inoperative/bypassed annunciation is provided. However, individual component groups are monitored to alert control room operators to system anomolies.

4. The following safety-related systems are normally operating and are furnished with system/component level inoperable/bypassed annunciation in the main control room:

   Reactor Plant Ventilation System (HVR) (Fig. No. 7.3-9)
   Control Building Air Conditioning System (HVC) (Fig. No. 7.3-13)
   Control Building Chilled Water System (HVK) (Fig. No. 7.3-14)
   Diesel Generator Building Ventilation System (HVP) (Fig. No. 7.3-18)
   Standby Service Water Pump House Ventilation System (HVY) (Fig. No. 7.3-9)
   Fuel Building Ventilation System (HVF) (Fig. No. 7.3-21)
   Containment Atmosphere Monitoring System (CMS) (Fig. No. 7.3-22)
   Fuel Pool Cooling System (SFC) (Fig. No. 7.6-7)

5. The following safety-related systems are manually-initiated and are furnished with system/component level inoperable/bypassed annunciation in the main control room:

   Main Steam Positive Leakage Control System (MS-PLCS) (Fig. No. 7.3-6)
   Hydrogen Mixing System (CPM) (Fig. No. 7.3-8)
   Hydrogen Recombiner System (HCS) (Fig. No. 7.3-10)
   Standby Liquid Control System (SLC) (Fig. No. 7.4-2)
   Penetration Valve Leakage Control System (LSV) (Fig. No. 7.6-8)

6. The following systems have inoperable component indications for isolation valves which are displayed in the main control room:

   Main Steam Safety/Relief System (SVV) (Fig. No. 7.5-10)
   Containment Hydrogen Purge System (CPP) (Fig. No. 7.5-8)
   Recirculation System (RCS) (Fig. No. 7.7-7)
   Ventilation Chilled Water System (HVN) (Fig. No. 7.5-5)
   Feedwater System (FWS) (Fig. No. 7.7-8)
   Reactor Water Cleanup System (WCS) (Fig. No. 7.5-7)
   Fire Protection System (FPW) (NA)
   Service Air System (SAS) (Fig. No. 7.5-4)
   Reactor Building Equipment Drains (DER) (Fig. No. 7.5-11)
   Condensate Makeup and Drawoff System (CNS) (Fig. No. 7.5-1)
   Reactor Plant Component Cooling Water System (CCP) (Fig. No. 7.5-2)
   Reactor Building Floor Drain System (DFR) (Fig. No. 7.5-6)
   Instrument Air System (IAS) (Fig. No. 7.5-3)

7. The design of the ISC System is such that it serves to multiply the LOCA signals originating from NSSS instrumentation to serve various control functions in affected systems. The system's simple design precludes a large number of possible failure modes. Therefore, RBS Unit 1 has not furnished the manual capability to activate the system level indicator.

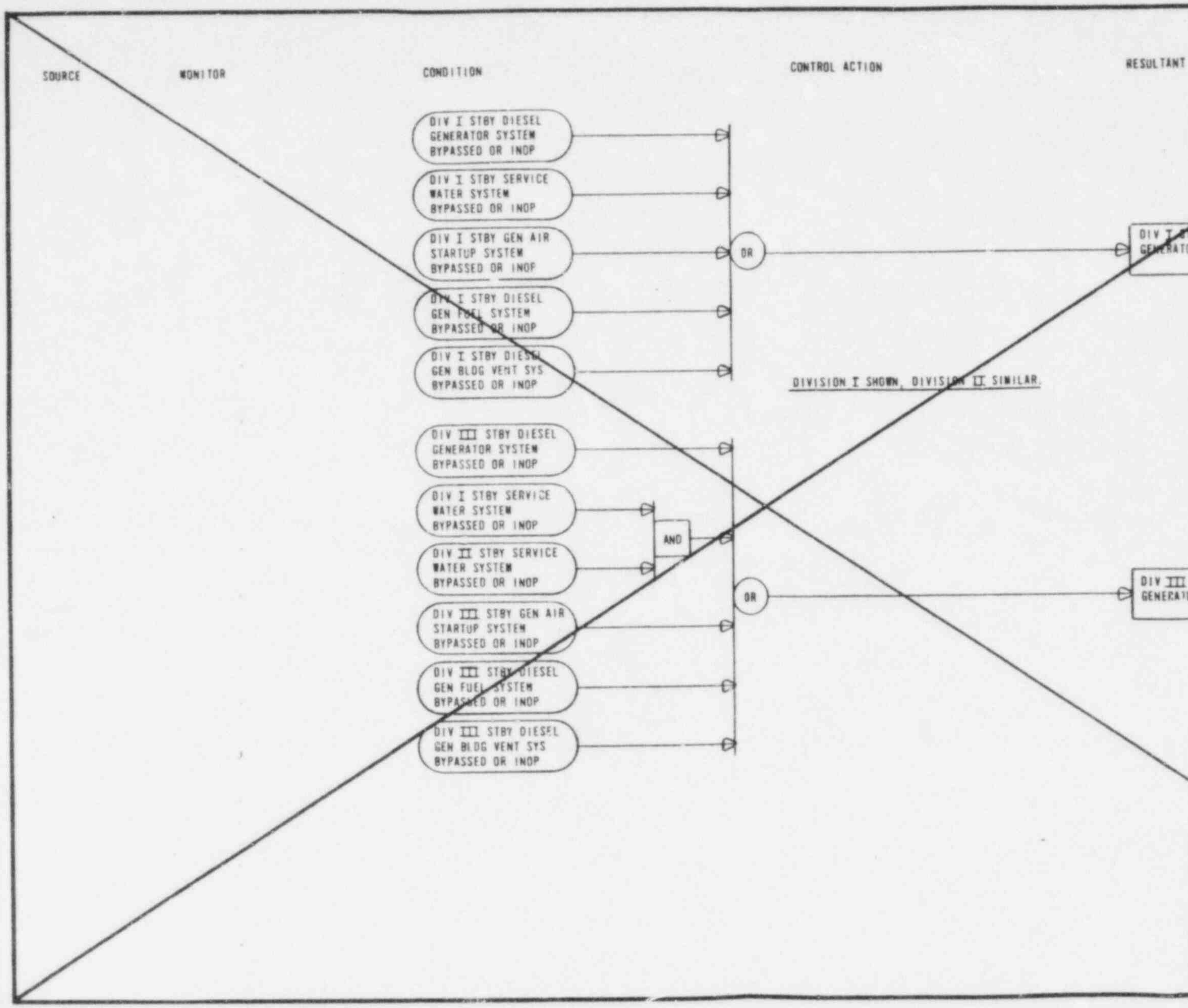

FIGURE 7.1-1

INOPERATIVE AND BYPASS LOGIC DIAGRAM SHEET 1 OF 5

RIVER BEND STATION
FINAL SAFETY ANALYSIS REPORT

DELETE

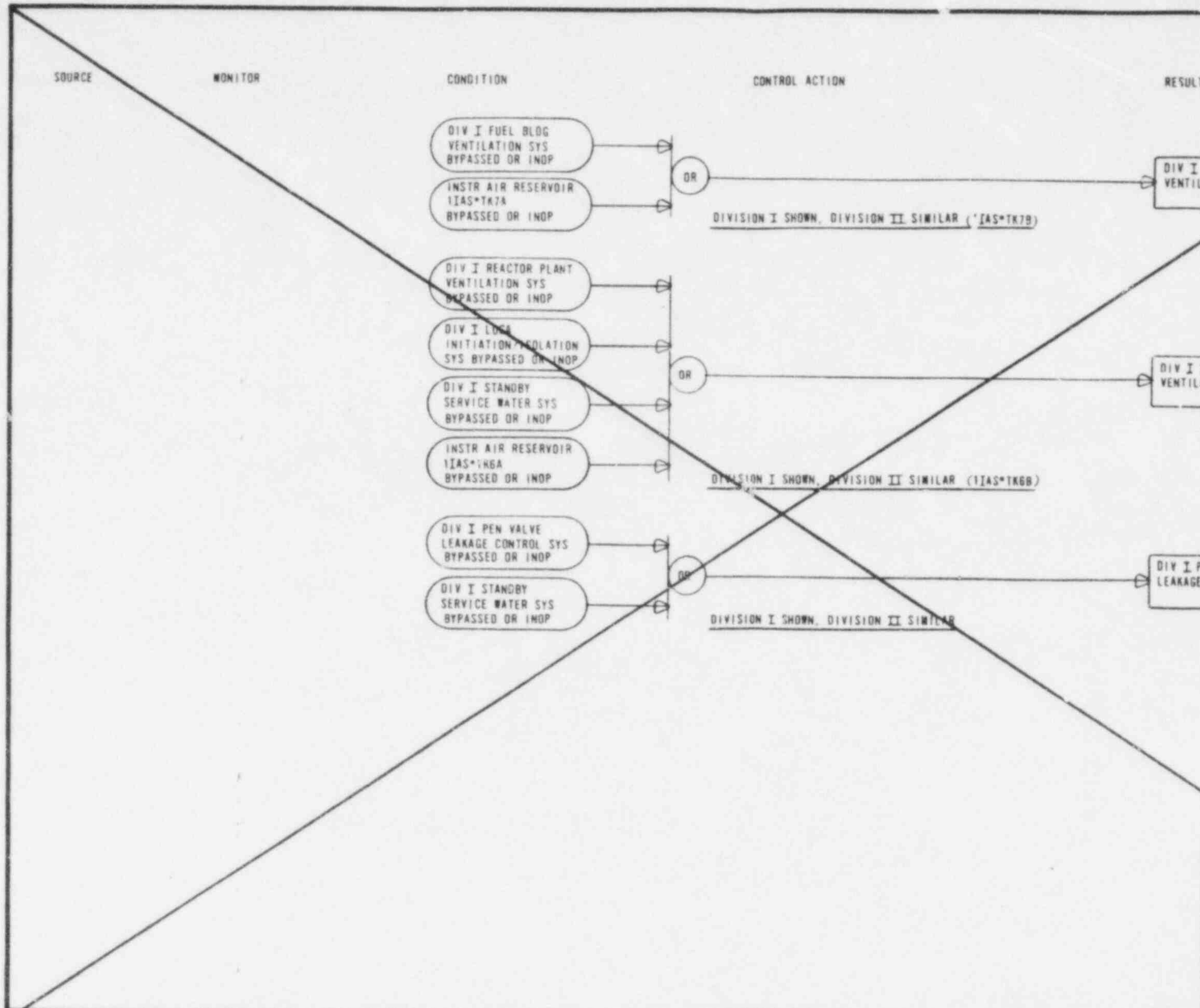

FIGURE 7.1-1

INOPERATIVE AND BYPASS LOGIC DIAGRAM SHEET 2 OF 5

RIVER BEND STATION
FINAL SAFETY ANALYSIS REPORT

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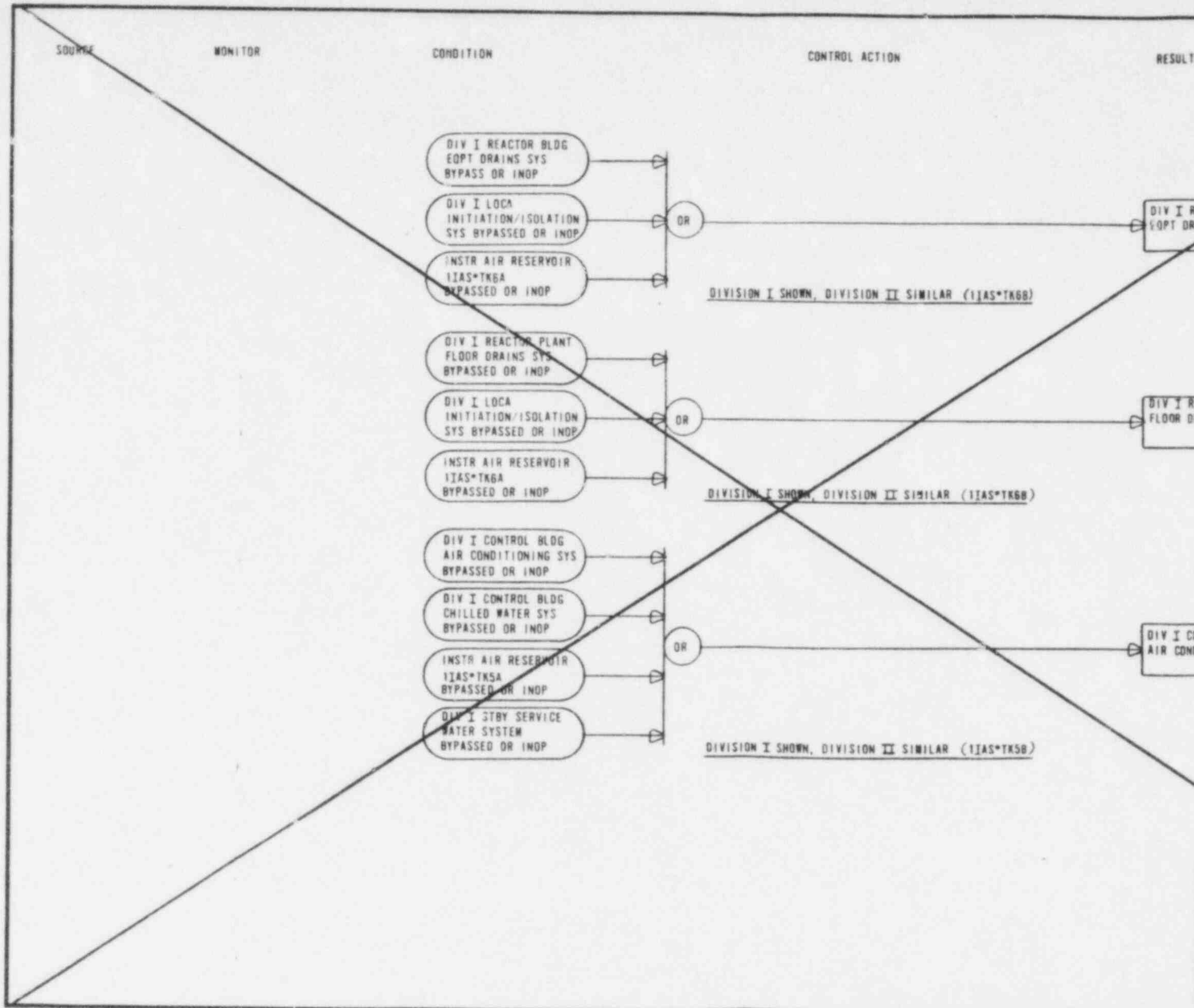

FIGURE 7.1-1

INOPERATIVE AND BYPASS LOGIC DIAGRAM SHEET 3 OF 5

RIVER BEND STATION
FINAL SAFETY ANALYSIS REPORT

DELETE

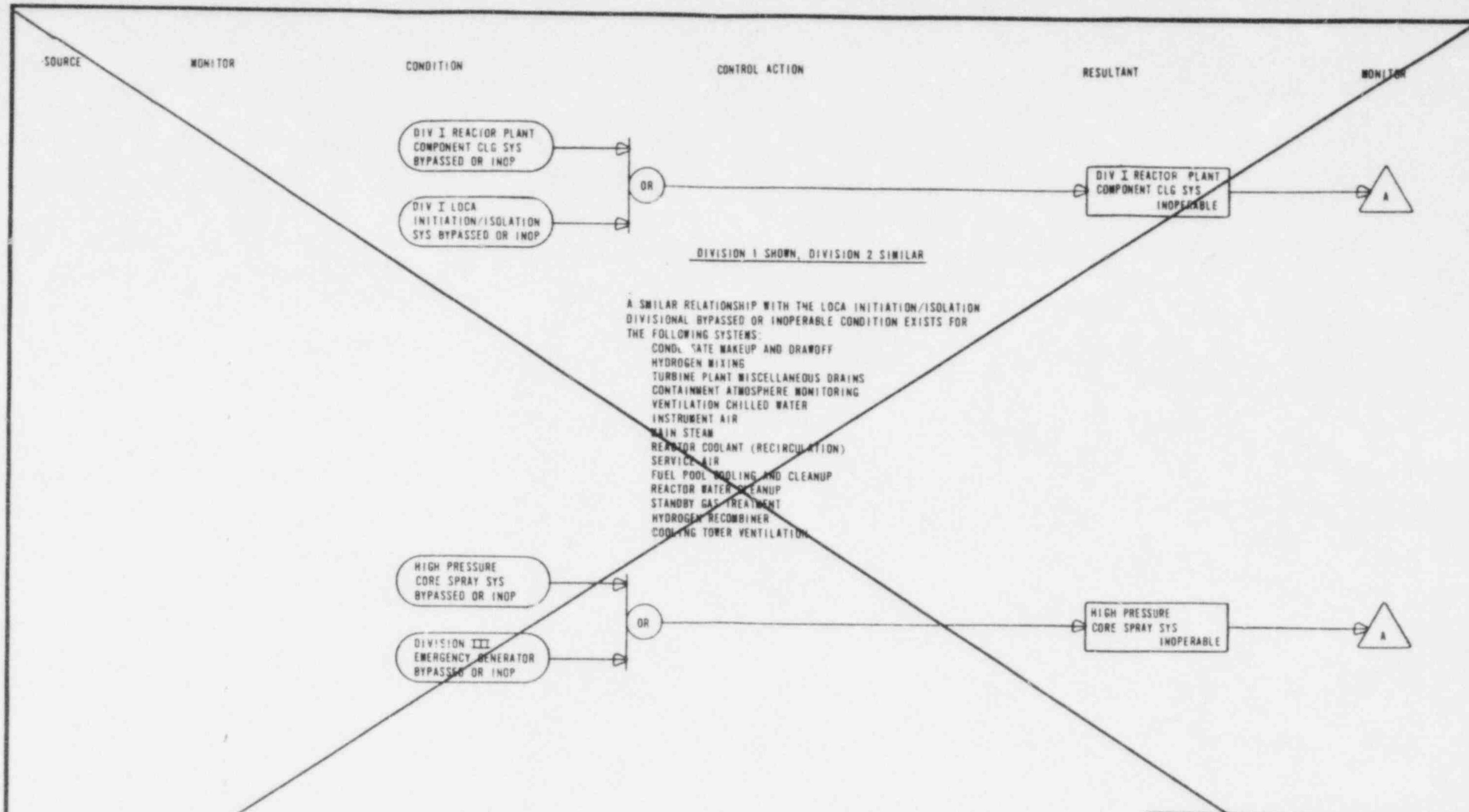

FIGURE 7.1-1

INOPERATIVE AND BYPASS LOGIC DIAGRAM SHEET 4 OF 5

RIVER BEND STATION
FINAL SAFETY ANALYSIS REPORT

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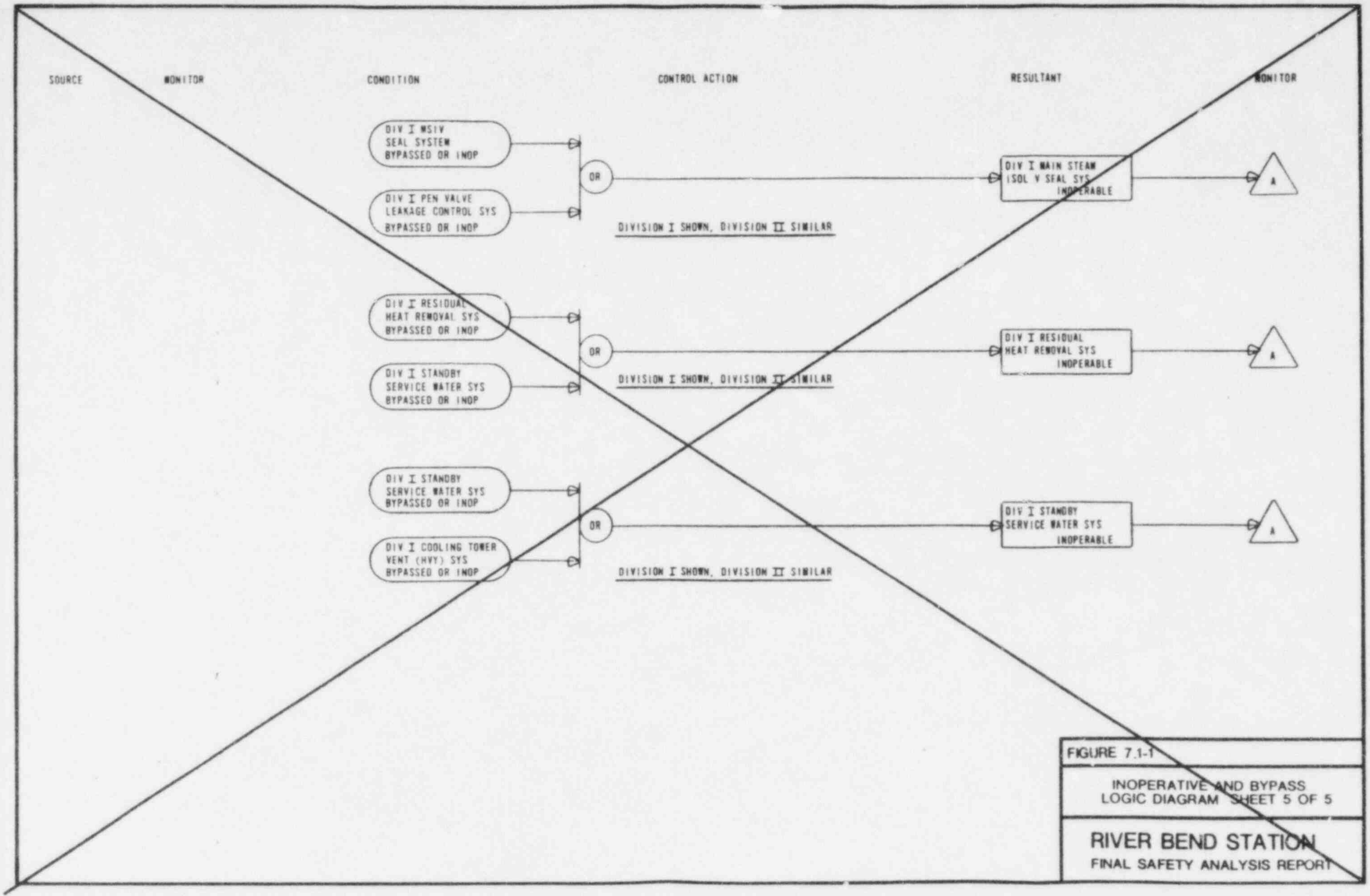

FIGURE 7.1-1

INOPERATIVE AND BYPASS LOGIC DIAGRAM SHEET 5 OF 5

RIVER BEND STATION
FINAL SAFETY ANALYSIS REPORT

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TABLE 1.8-1 (Cont)

Regulatory Guide 1.47 (May 1973)

Bypassed and Inoperable Status Indication
for Nuclear Power Plant Safety Systems

Project Position - Comply ~~Compliance shall be implemented~~ with the following clarifications:

1. An indicator of bypass/inoperability, located in the main control room, is provided for redundant or diverse portions of each (1) safety system. Bypass indication is provided for ~~any deliberate~~ operator ~~action~~ actions that render~~s~~ ~~a safety~~ the system inoperable.

2. Bypass of redundant portions of (1) engineered safety feature support systems warrants indicators that must be differentiated from safety system bypass indicators. To reflect the impact on the safety system, bypass of the support system also actuates the safety system bypass indicators.

FSAR Sections - 7.1.2, ~~8.2.1,~~ 8.3.1

(1) automatically actuated

ENCLOSURE 8

QUESTION 421.009 (7.1)

Several previously reviewed BWR installations, e.g., Grand Gulf, include a start-up transient monitoring system to provide recordings of selected parameters during the start-up and warranty testing. There is no information in the FSAR which describes this system. If this system, or any similar system, is intended for use in the River Bend units, provide the following information:

(a) Identify all safety-related parameters which will be monitored with the transient monitoring system during start-up.

(b) For each safety parameter identified above, provide a concise description of how the associated circuitry merges or connects (either directly, or indirectly by means of isolation devices) with the circuitry associated with the transient monitoring system. Where appropriate, supplement this description with detailed electrical schematics.

(c) Describe provisions of the design to prevent failures of this system from degrading safety-related systems.

RESPONSE

~~A computer-based data acquisition and analysis system (Emergency Response Information System) is used to perform emergency response facility functions (i.e., safety parameter display system) and startup transient monitoring type functions~~.

REPLACE WITH INSERT

~~The following parameters in safety related systems are monitored for startup transient testing will be provided by October 1983~~.

~~The equipment monitoring safety related functions are permanently installed to the same standards as all other plant equipment and are consistent with the separation requirements of Regulatory Guide 1.75~~.

~~Isolation is accomplished by transmission via optical fiber cable. The optical isolation is accomplished downstream of signal conditioning, multiplexing, and analog-to-digital conversion. These remote multiplexers are classified as divisional devices. Thus, within a given multiplexer only signals of one safety division are connected. The signal conditioning and multiplexer unit are qualified in~~

~~accordance with Regulatory Guides 1.89 and 1.100. The associated portion of the optical isolation is qualified in accordance with Regulatory Guides 1.89 and 1.100~~.

~~To maintain the signal conditioning and multiplexing equipment as divisional devices, the power for these devices is supplied from divisional power sources. In addition, each signal input to the multiplexers is individually conditioned and buffered from all other signals in the same multiplexer~~.

INSERT (for Pg. Q&R 7.1-5)

A computer-based data acquisition and analysis system (Emergency Response Information System) as described in Section 7.7.1.7 is used to perform emergency response facility functions (i.e., safety parameter display system) amd startup transient monitoring type functions. A system description is also provided in GE Licensing Topical Report NEDE-30284-P.

The equipment monitoring safety-related functions is permanently installed to the same standards as all other safety-related equipment and complies with the separation requirements of Regulatory Guide 1.75.

Isolation is accomplished by transmission via optical fiber cable. The optical isolation is accomplished downstream of signal conditioning, and analog-to-digital conversion. The remote multiplexers are classified as Class 1E where Class 1E power is furnished to the multiplexer unit. Thus, within a given multiplexer only signals of one safety division are connected. Those portions of the system that are required to meet Class 1E requirements for electrical isolation are qualified in accordance with IEEE 323 (1974) and IEEE 344 (1975). Additional information on isolation devices is provided in the response to Question 421.10.

To maintain the signal conditioning and multiplexing equipment as divisional devices where required, the power for these devices is supplied from divisional power sources. In addition, each signal input to the multiplexers is individually conditioned and buffered from all other signals in the same multiplexer.

ENCLOSURE 9

QUESTION 421.010 (7.1)

Various instrumentation and control system circuits in the plant (including the reactor protection system, engineered safety features actuation system, instrument power supply distribution system) rely on certain devices to provide electrical isolation capability in order to maintain the independence between redundant safety circuits and between safety circuits and non-safety circuits. Therefore, provide the following information:

(a) Identify the types of isolation devices which are used as boundaries to isolate non-safety-grade circuits from the safety-grade circuits or to isolate redundant safety-grade circuits.

(b) Provide the acceptance criteria for each isolation device identified in response to part (a) above.

(c) Describe the type of testing that was conducted on the isolation devices to ensure adequate protection against EMI (i.e., noise), short-circuit failures, voltage faults, and/or surges.

RESPONSE

The response to this request ~~will be provided by September 1983.~~ is provided in new Section 7.1.4.

trip point or low trip point. This allows trip relays either to be energized or deenergized during normal operation.

The slave trip unit is used in conjunction with a master trip unit when different set points from a common transmitter are desired. The slave trip unit receives its input signal from the analog output of a master trip unit.

The calibration unit furnishes the means by which an in-place calibration check of the master and slave trip units can be performed. The calibrator contains a stable current source and a transient current source. The stable current is for verification of the calibration point of any given channel. The transient current source is used to provide a step current input into a selected trip unit such that the response time of that channel can be determined.

Electrical system equipment protective relay trip setpoint selection is based upon the worst manufacturer's relay tolerances with proper margins applied to reflect any actual operating data. This selection criteria and periodic surveillance avoids premature tripping of safety-related circuits due to setpoint drift. 3

INSERT SECTION 7.1.4

INSERT (for Fg. 7.1-13)

7.1.4 Isolation Devices

Two general types of devices; relays and optical isolators, are used to provide isolation between Class 1E circuits of different divisions or between Class 1E and Non-Class 1E circuits. Other devices are also used in limited applications to provide isolation.

7.1.4.1 Relays

Relays are used to provide contact-to-contact or coil-to-contact isolation. Relays qualified for use as isolation devices are tested to verify the relays will satisfactorily perform their Class 1E safety functions under: 1) The full usage of input voltages at given environmental conditions: 2) The full range input voltages for normal environmental conditions at worst case seismic accelerations for individual locations within the plant. Tests are also performed to verify that the relays can provide separation of their redundant segments so they can perform their safety-related functions in an intense fire. The test consists of generating a 10,000 Btu fire with a 600 C temperature spike in which each of the relay types utilized for isolation was immersed.

The acceptance criterion is that a failure would not occur in any of the contact or coil circuits. Test results are acceptable.

7.1.4.2 Optical Isolators

Optical isolators consist of an input and output isolator card which provide for an electrical and thermal barrier between the input and output. Each signal transmitted from the input side to the output side is optically coupled by means of a ligh-emitting-diode, a quartz rod, and a phototransistor. The quartz rod acts as a light pipe.

The acceptance criterion for isolators is their ability to provide electrical isolation and thermal isolation in terms of protection against the spread of fire.

Conductive electromagnetic interference (EMI) tests using 100 to 500 KHz, 300 volts peak-to-peak test signals, and radiated EMI tests using 0.5 to 100 MHz, 5 volt peak-to-peak test signals are performed.

The acceptance criterion is that no malfunction, undesired response, degradation of performance, or permanent damage occur during the EMI testing.

7.1.4.3 Other Devices Used to Provide Isolation

a. Circuit Breakers

The circuit breakers within the RPS power supply distribution cabinets are used as functional isolators, for the purpose of defining the transmition point from non-divisional to divisional circuits.

The RPS divisional circuits and loads fed from these circuit breakers cannot introduce any unsafe failure mode, but can trip on overcurrent and give an RPS channel trip condition. This is a safe direction trip condition.

The circuit breakers (although non-class 1E devices) are acceptable functional isolators for purposes of defining the transmition from non-divisional to divisional fail-safe circuits. The transition point for RPS power is the C71-P001/P002 cabinets (Non-Class 1E) which contain the functional isolators.

There is no credible event that would become a safety concern to the RPS circuit fed or to the plant.

Circuit breakers when interposed between two fail-safe divisions, can prevent an unsafe failure mode from propagating from one division to the other and the circuit breakers provide functional isolation. The fail-safe concept of the RPS system allows the use of Non-Class 1E circuit breakers and distribution cabinets. Divisional isolation in the RPS power distribution cabinets is covered by analysis.

b. Auxiliary Current Transformer

Class 1E auxiliary current transformers are used to input Class 1E bus amperage to non-Class 1E current transducers used for watt-hour meters. Auxiliary current transformers are an isolation devices as per IEEE 384 (1977), Section 6.2. Auxiliary current transformers along with the switchgear assembly are tested and qualified in accordance with IEEE 323 (1974).

ENCLOSURE 10

QUESTION 421.012 (7.1, 7.2, 7.3)

Describe in detail how physical separation is maintained between protection channel circuits, protection logic circuits, and non-safety-related circuits. The channel independence described in FSAR Section 8.3.1 (Referenced by both FSAR Sections 7.2 and 7.3 regarding independence of redundant protection system channels) pertains to power cabling; not instrument channel and logic circuitry.

RESPONSE

~~The response to this request will be provided by September 1983~~.

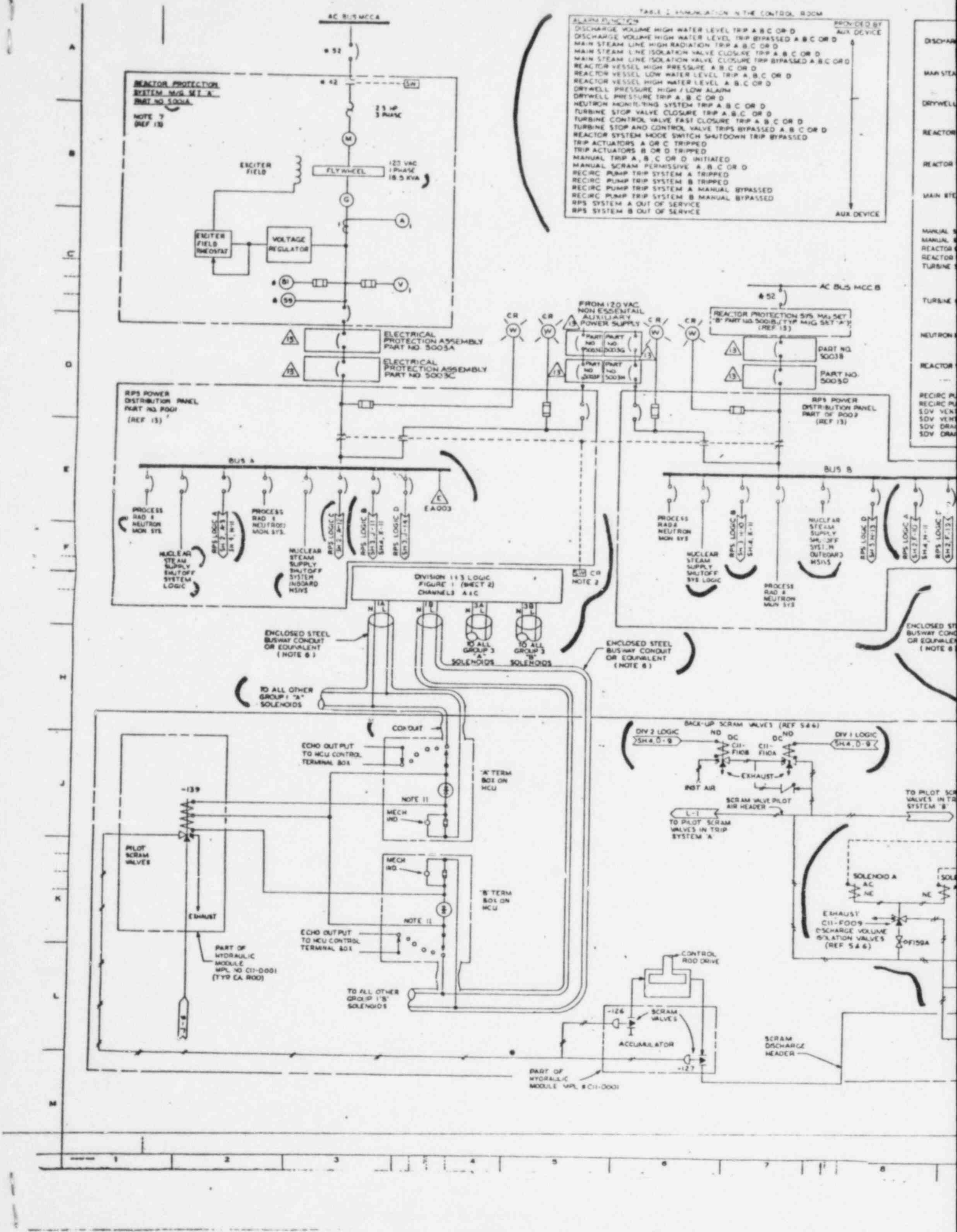
REPLACE WITH INSERT

INSERT (for Pg. Q&R 7.1-9)

Sections 8.3.1.4 through 8.3.1.4.4.3, as revised in response to Power Systems Branch (PSB) questions, address the physical separation and independence for protection system instrument and control channel circuitry. The RBS position on R.G. 1.75 Revision 2 has been revised to clarify PSB concerns.

Separation criteria and methods for electrical circuitry in instrument cabinets/racks, local control panels, main control room vertical boards and benchboards, and the power generation control complex (PGCC) are discussed in the response to Question 421.037.

ENCLOSURE 11


AC BUS MCC A
REACTOR PROTECTION SYSTEM M/G SET 'A' PART NO 5001A
NOTE 7 (REF 13)
25 HP 3 PHASE
EXCITER FIELD
FLYWHEEL
120 VAC 1 PHASE 18.5 KVA
EXCITER FIELD RHEOSTAT
VOLTAGE REGULATOR
ELECTRICAL PROTECTION ASSEMBLY PART NO. 5003A
ELECTRICAL PROTECTION ASSEMBLY PART NO. 5003C
RPS POWER DISTRIBUTION PANEL PART NO. P001 (REF 13)
BUS A
PROCESS RAD & NEUTRON MON SYS
NUCLEAR STEAM SUPPLY SHUTOFF SYSTEM LOGIC
NUCLEAR STEAM SUPPLY SHUTOFF SYSTEM INBOARD MSIVS
EA003
DIVISION 1 & 3 LOGIC FIGURE 1 (SHEET 2) CHANNELS A & C
CR NOTE 2
FROM 120 VAC NON ESSENTIAL AUXILIARY POWER SUPPLY
TABLE 2 ANNUNCIATION IN THE CONTROL ROOM
ALARM FUNCTION
PROVIDED BY AUX DEVICE
DISCHARGE VOLUME HIGH WATER LEVEL TRIP A B C OR D
DISCHARGE VOLUME HIGH WATER LEVEL TRIP BYPASSED A B C OR D
MAIN STEAM LINE HIGH RADIATION TRIP A B C OR D
MAIN STEAM LINE ISOLATION VALVE CLOSURE TRIP A B C OR D
MAIN STEAM LINE ISOLATION VALVE CLOSURE TRIP BYPASSED A B C OR D
REACTOR VESSEL HIGH PRESSURE A B C OR D
REACTOR VESSEL LOW WATER LEVEL TRIP A, B, C OR D
REACTOR VESSEL HIGH WATER LEVEL A B, C OR D
DRYWELL PRESSURE HIGH / LOW ALARM
DRYWELL PRESSURE TRIP A, B C OR D
NEUTRON MONITORING SYSTEM TRIP A B C OR D
TURBINE STOP VALVE CLOSURE TRIP A B C OR D
TURBINE CONTROL VALVE FAST CLOSURE TRIP A B C OR D
TURBINE STOP AND CONTROL VALVE TRIPS BYPASSED A B C OR D
REACTOR SYSTEM MODE SWITCH SHUTDOWN TRIP BYPASSED
TRIP ACTUATORS A OR C TRIPPED
TRIP ACTUATORS B OR D TRIPPED
MANUAL TRIP A, B, C OR D INITIATED
MANUAL SCRAM PERMISSIVE A, B, C OR D
RECIRC PUMP TRIP SYSTEM A TRIPPED
RECIRC PUMP TRIP SYSTEM B TRIPPED
RECIRC PUMP TRIP SYSTEM A MANUAL BYPASSED
RECIRC PUMP TRIP SYSTEM B MANUAL BYPASSED
RPS SYSTEM A OUT OF SERVICE
RPS SYSTEM B OUT OF SERVICE
AUX DEVICE
AC BUS MCC B
REACTOR PROTECTION SYS M/G SET 'B'
PART NO. 5003B
PART NO. 5003D
RPS POWER DISTRIBUTION PANEL PART OF P002 (REF 13)
BUS B
PROCESS RAD & NEUTRON MON SYS
NUCLEAR STEAM SUPPLY SHUTOFF SYS LOGIC
NUCLEAR STEAM SUPPLY SHUTOFF SYSTEM OUTBOARD MSIVS
ENCLOSED STEEL BUSWAY CONDUIT OR EQUIVALENT (NOTE 6)
TO ALL GROUP 3 "A" SOLENOIDS
TO ALL GROUP 3 "B" SOLENOIDS
TO ALL OTHER GROUP 1 "A" SOLENOIDS
CONDUIT
ECHO OUTPUT TO HCU CONTROL TERMINAL BOX
"A" TERM BOX ON HCU
NOTE 11
MECH IND
PILOT SCRAM VALVES
EXHAUST
"B" TERM BOX ON HCU
PART OF HYDRAULIC MODULE MPL NO C11-D001 (TYP EA ROD)
TO ALL OTHER GROUP 1 "B" SOLENOIDS
CONTROL ROD DRIVE
SCRAM VALVES
ACCUMULATOR
PART OF HYDRAULIC MODULE MPL # C11-D001
SCRAM DISCHARGE HEADER
BACK-UP SCRAM VALVES (REF 5 & 6)
DIV 2 LOGIC
DIV 1 LOGIC
INST AIR
EXHAUST
SCRAM VALVE PILOT AIR HEADER
TO PILOT SCRAM VALVES IN TRIP SYSTEM 'A'
SOLENOID A
EXHAUST
C11-F009 DISCHARGE VOLUME ISOLATION VALVES (REF 5 & 6)

REACTOR PROTECTION SYSTEM

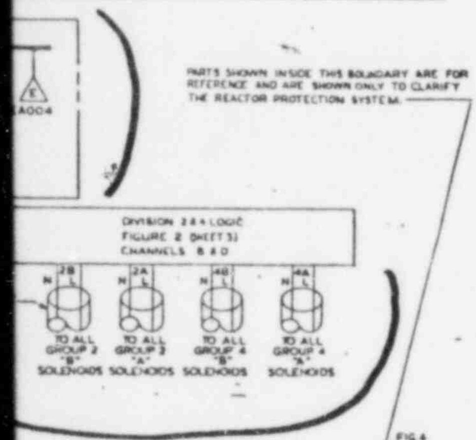
MPL NO C71-1010

OVERALL REVISION	1

SHEET	REV
1	1
2	1
3	1
4	1

TABLE II ALARM INPUTS TO COMPUTER

ALARM FUNCTION	CHANNEL	COMPUTER INPUT NUMBER
...OLUME HIGH WATER LEVEL TRIP	A	C11-NC033
	B	C11-NC034
	C	C11-NC035
	D	C11-NC036
...NE ISOLATION VALVE CLOSURE TRIP	A	B21-NC047
	B	B21-NC048
	C	B21-NC049
	D	B21-NC050
...H PRESSURE TRIP	A	C71-NC001
	B	C71-NC002
	C	C71-NC003
	D	C71-NC004
...H PRESSURE TRIP	A	B21-NC001
	B	B21-NC002
	C	B21-NC003
	D	B21-NC004
...ER LEVEL 3 TRIP	A	B21-NC005
	B	B21-NC006
	C	B21-NC007
	D	B21-NC008
...LINE HIGH RADIATION TRIP	A	D17-NC001
	B	D17-NC002
	C	D17-NC003
	D	D17-NC004
...AM TRIP DIV 1 & 3	AC	C71-NC005
...AM TRIP DIV 2 & 4	BD	C71-NC008
...AM TRIP DIV 1 & 3	AC	C71-NC009
...AM TRIP DIV 2 & 4	BD	C71-NC010
...P VALVE CLOSURE TRIP	A	C71-NC013
	B	C71-NC014
	C	C71-NC015
	D	C71-NC016
...TROL VALVE FAST CLOSURE TRIP	A	C71-NC017
	B	C71-NC018
	C	C71-NC019
	D	C71-NC020
...NITORING SYSTEM TRIP	A	C51-NC091
	B	C51-NC092
	C	C51-NC093
	D	C51-NC094
...ER LEVEL 8 TRIP	A	B21-NC051
	B	B21-NC052
	C	B21-NC053
	D	B21-NC054
... TRIP SYSTEM "A"	A	C71-NC025
... TRIP SYSTEM "B"	B	C71-NC026
...LVE C11-F010 CLOSED	—	C11-NC064
...LVE C11-F180 CLOSED	—	C11-NC065
...AVE C11-F011 CLOSED	—	C11-NC066
...LVE C11-F181 CLOSED	—	C11-NC067



NOTES:

1. TRIP CHANNELS FOR THE "TURBINE CONTROL VALVE FAST CLOSURE" TRIP SHALL BE DERIVED FROM THOSE EVENTS CAUSING FAST CLOSURE OF THE CONTROL VALVES.
2. SYSTEM SHALL BE ARRANGED SO THAT THE BUS CANNOT BE ENERGIZED FROM THE M/G SET AND ALTERNATE SOURCE SIMULTANEOUSLY.
3. DELETED.
4. MAIN STEAM LINE ISOLATION VALVE CLOSURE TRIP SHALL BE ARRANGED SO THAT ANY ONE STEAM LINE MAY BE ISOLATED (BY FULL CLOSURE OF ITS ISOLATION VALVES) AND THE ISOLATION VALVE FOR ANY ONE OTHER STEAM LINE CAN BE CLOSED (MORE THAN 10%) WITHOUT CAUSING A SCRAM.
5. LOGIC FOR THE "TURBINE STOP VALVE CLOSURE" TRIP SHALL BE ARRANGED SO THAT CLOSURE OF 3 OUT OF 4 STOP VALVES WILL CAUSE A SCRAM.
6. FOR ANY SINGLE ROD GROUP (A) (TC) A AND B SOLENOID CABLES MAY BE RUN TOGETHER IN ONE CONDUIT WITH NO OTHER WIRING.
7. EQUIPMENT RATINGS ARE ESTIMATED AND PRELIMINARY. ACTUAL VALVES TO BE DETERMINED AT THE TIME OF EQUIPMENT PROCUREMENT.
8. EACH MAIN STEAM LINE RADIATION MONITOR MONITORS ALL FOUR MAIN STEAM LINES.
9. ALL EQUIPMENT & INSTRUMENTS ARE PREFIXED BY SYSTEM NUMBER (C71) UNLESS OTHERWISE NOTED.
10. FOR LOCATION AND IDENTIFICATION OF INSTRUMENTS SEE INSTRUMENT DATA SHEET LISTED IN THE MPL FOR EACH INSTRUMENT.
11. SELENIUM THYRECTOR SUPPRESSORS (OR EQUIVALENT) SHALL BE USED TO SUPPRESS ELECTRICAL ARCING CAUSED BY THE SCRAM SOLENOIDS.
12. THIS DISCHARGE VOLUME HIGH LEVEL BYPASS SWITCH SHALL BE SO CONSTRUCTED THAT RPS CHANNELS A AND C ARE PHYSICALLY SEPARATED FROM CHANNELS B & D.

15. CLASS 1E ELECTRICAL PROTECTION ASSEMBLY (EPA) TRIP EPA CIRCUIT BREAKER ON OVER VOLTAGE, UNDER VOLTAGE OR UNDER FREQUENCY.

REFERENCE DOCUMENTS:	MPL ITEM NO.
1 PROCESS COMPUTER INPUT/OUTPUT REQUIREMENTS	C91-4010
2 NEUTRON MONITORING SYS IED	C51-1010
3 NEUTRON MONITORING SYS FCD	C51-1020
4 NUCLEAR BOILER SYS FCD	B21-1030
5 CONTROL ROD DRIVE HYD SYS P&ID	C11-1010
6 CONTROL ROD DRIVE HYD SYS FCD	C11-1030
7 NUCLEAR BOILER SYS P&ID	B21-1010
8 RESIDUAL HEAT REMOVAL SYS P&ID	E12-1010
9 PROCESS RADIATION MON SYS IED	D17-1010
10 REACTOR RECIRC SYS P&ID	B33-1010
11 TURBINE GENERATOR & STEAM BYPASS SYS DESIGN SPEC	A62-4120
12 PROCESS COMP I/O LIST	C91-4030
13 RPS MG SET ELEM DIAG	C71-1060

SUPPORTING DOCUMENTS:	MPL ITEM NO.
1 PIPING & INSTRUMENT SYMBOLS	A42-1010
2 LOGIC SYMBOLS	A42-1050

LEGEND:

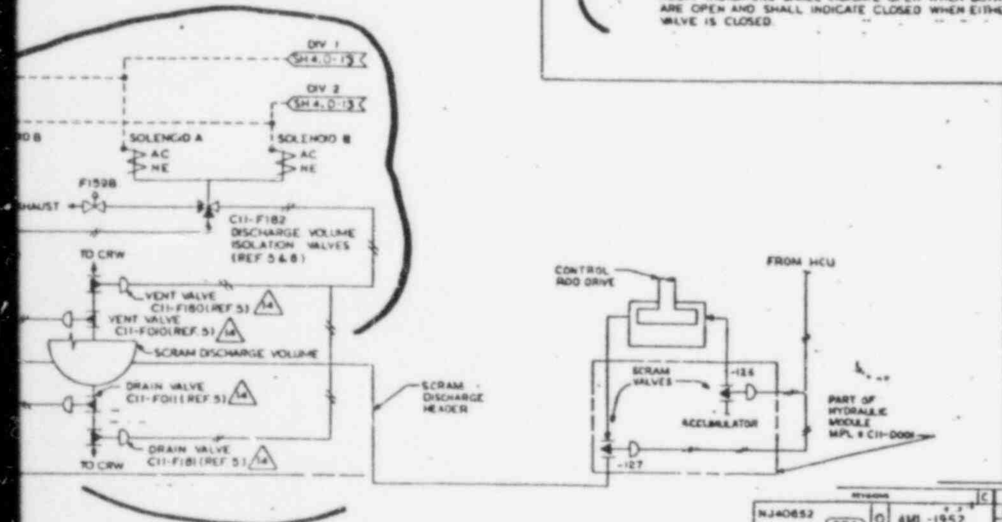
* = SWITCHGEAR DEVICE FUNCTION NUMBER ANSI SPEC. C37.2

C = COMPUTER INPUT DESIGNATIONS

E = ERIS TERMINAL DESIGNATIONS

NOTES: CONTINUED

14. SCRAM DISCHARGE VOLUME VENT & DRAIN VALVE CONTROL ROOM INDICATORS SHALL INDICATE OPEN WHEN BOTH VALVES ARE OPEN AND SHALL INDICATE CLOSED WHEN EITHER VALVE IS CLOSED.



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CHK BY: E. ROSNER		1	RETRACE W/CHNG SH 2

762E427AA

ATTACHED TO: RBS-T-13644

To be new Fig. 7.2-1 (4 Sheets)

Q 421.016 Q 421.021

PRC APERTURE CARD

Also Available On Aperture Card

8312290277-01

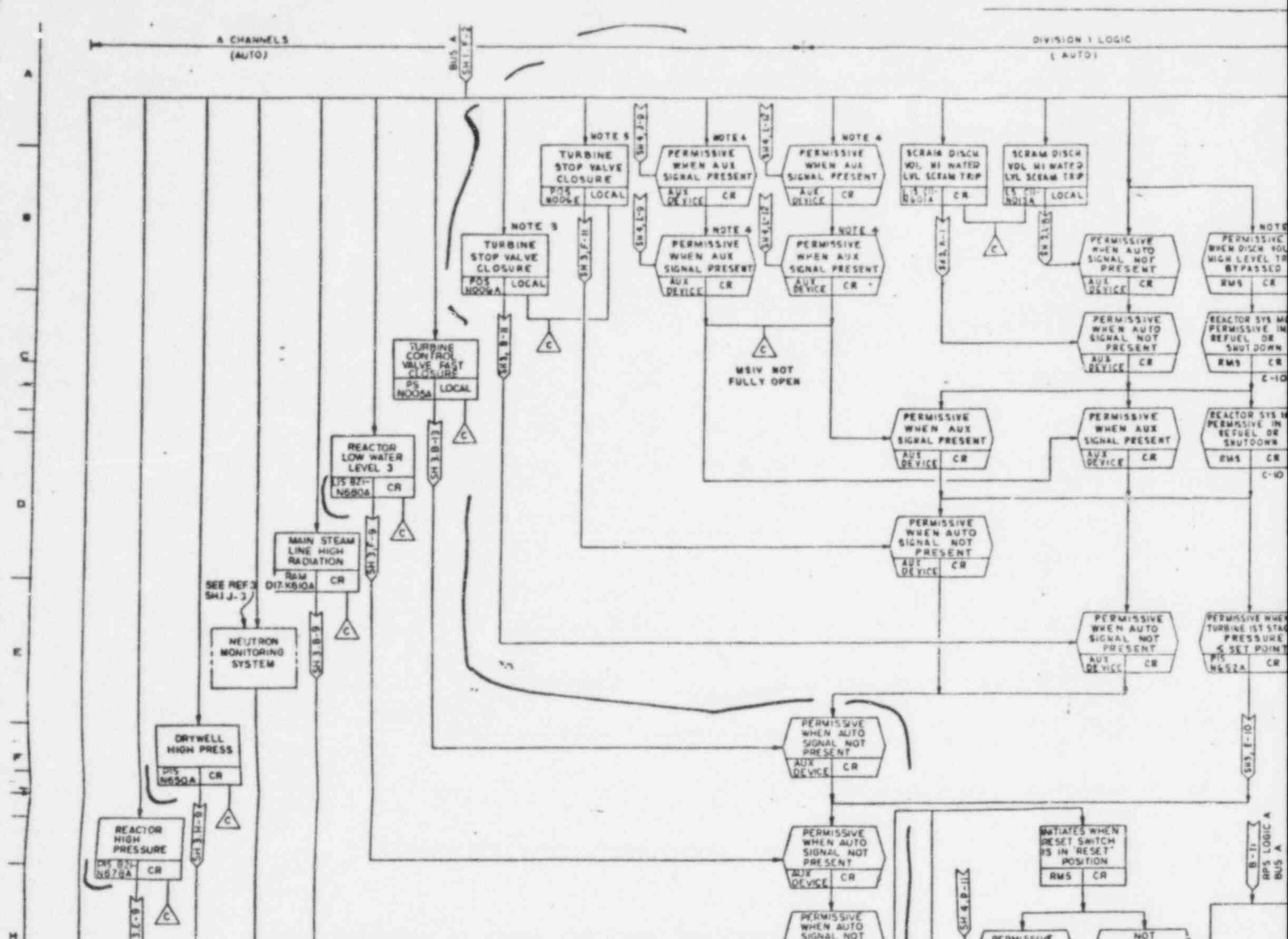
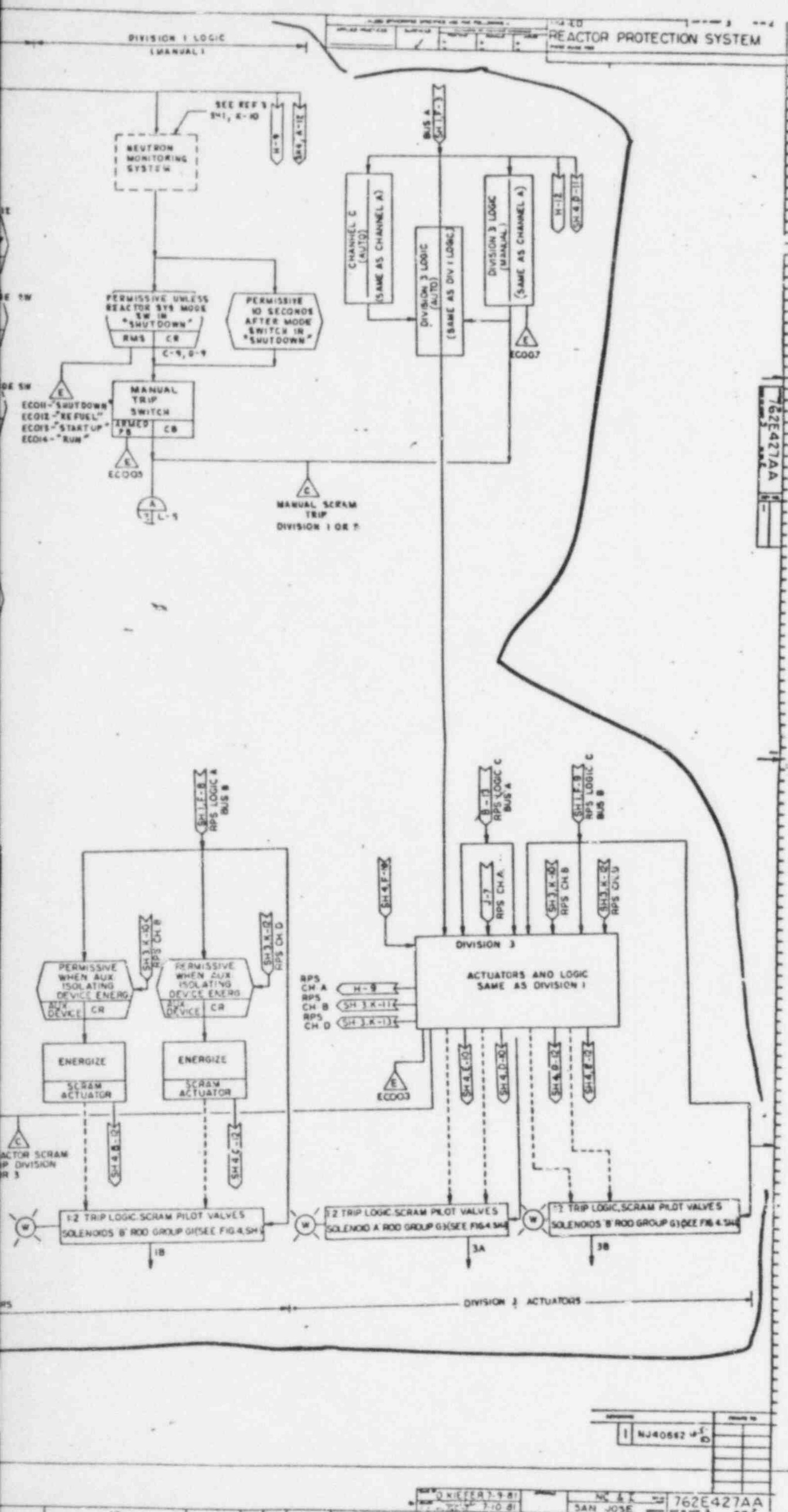


FIG 1
DIVISIONS 1 & 3 LOGIC
(FOR ALARM FUNCTIONS SEE TABLE 1.SH1)

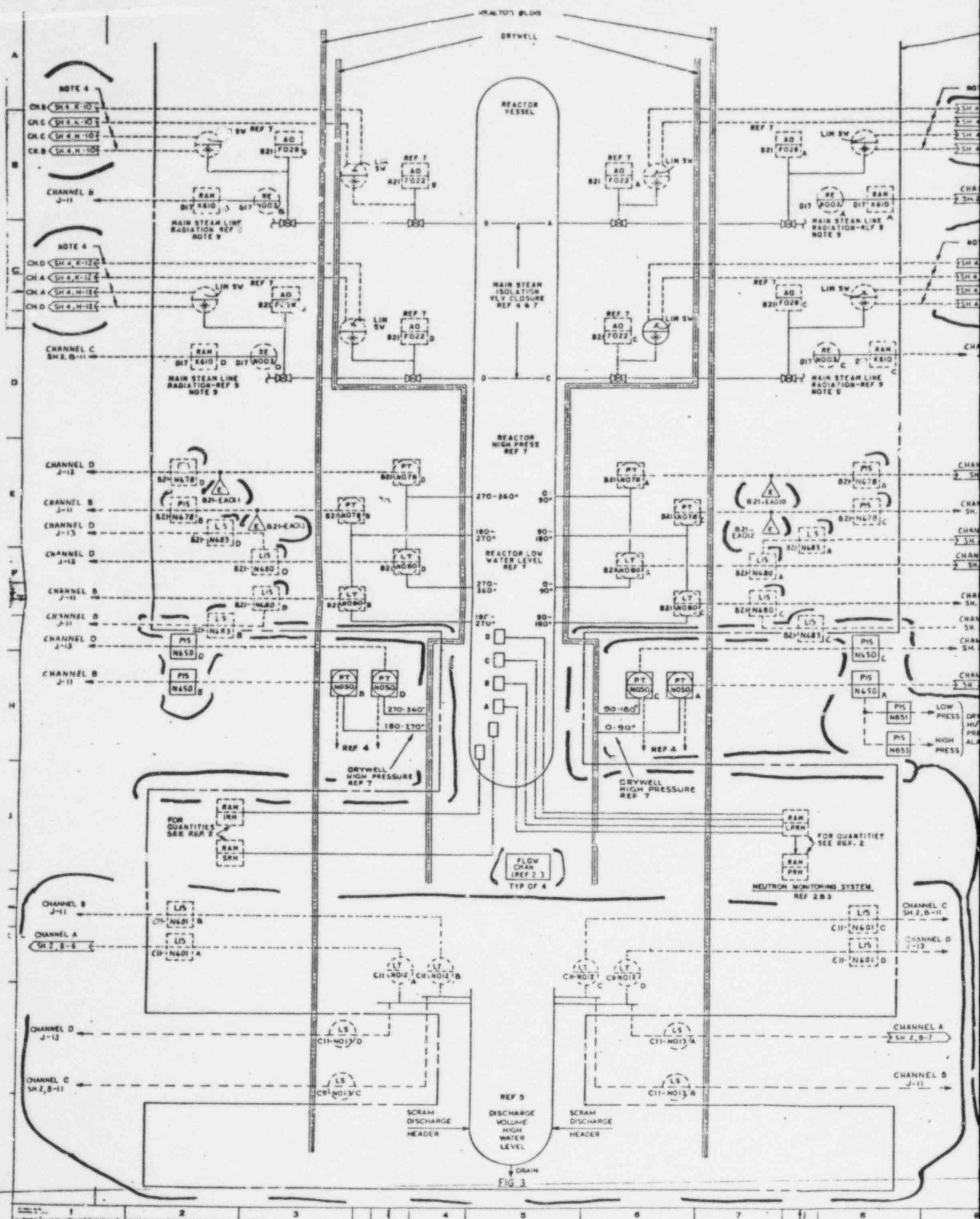


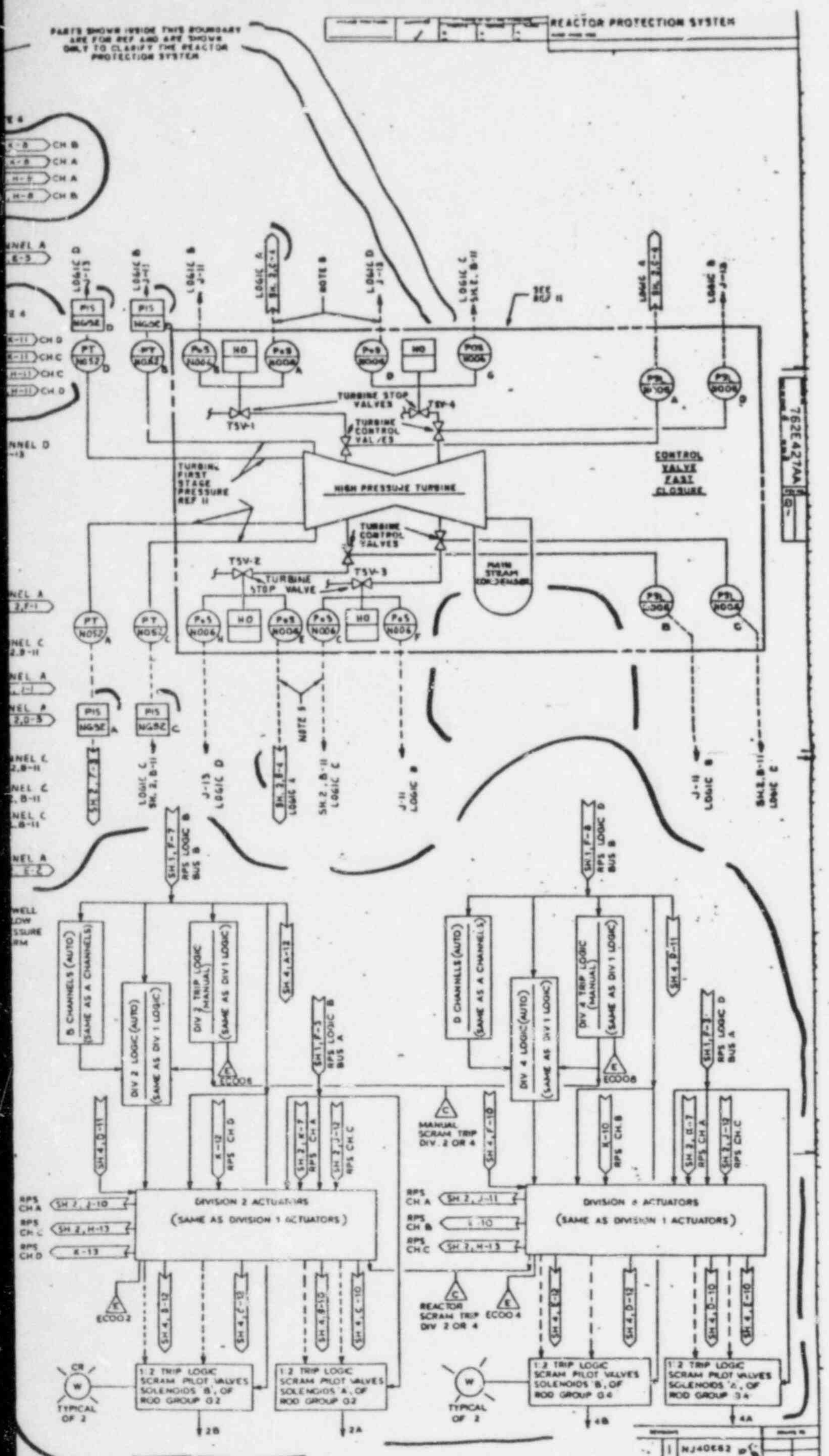
Also Available On
Aperture Card

APERTURE
CARD

ATTACHED TO: RBS-T-1364X

8312290277-07


REACTOR BLDG
DRYWELL
REACTOR VESSEL
MAIN STEAM ISOLATION VLV CLOSURE REF 4 & 7
REACTOR HIGH PRESS REF 7
REACTOR LOW WATER LEVEL REF 7
DRYWELL HIGH PRESSURE REF 7
FOR QUANTITIES SEE REF. 2
NEUTRON MONITORING SYSTEM REF 2 & 3
FLOW CHAN (REF 2) TYP OF 4
REF 5
SCRAM DISCHARGE HEADER
DISCHARGE VOLUME HIGH WATER LEVEL
DRAIN
FIG 3

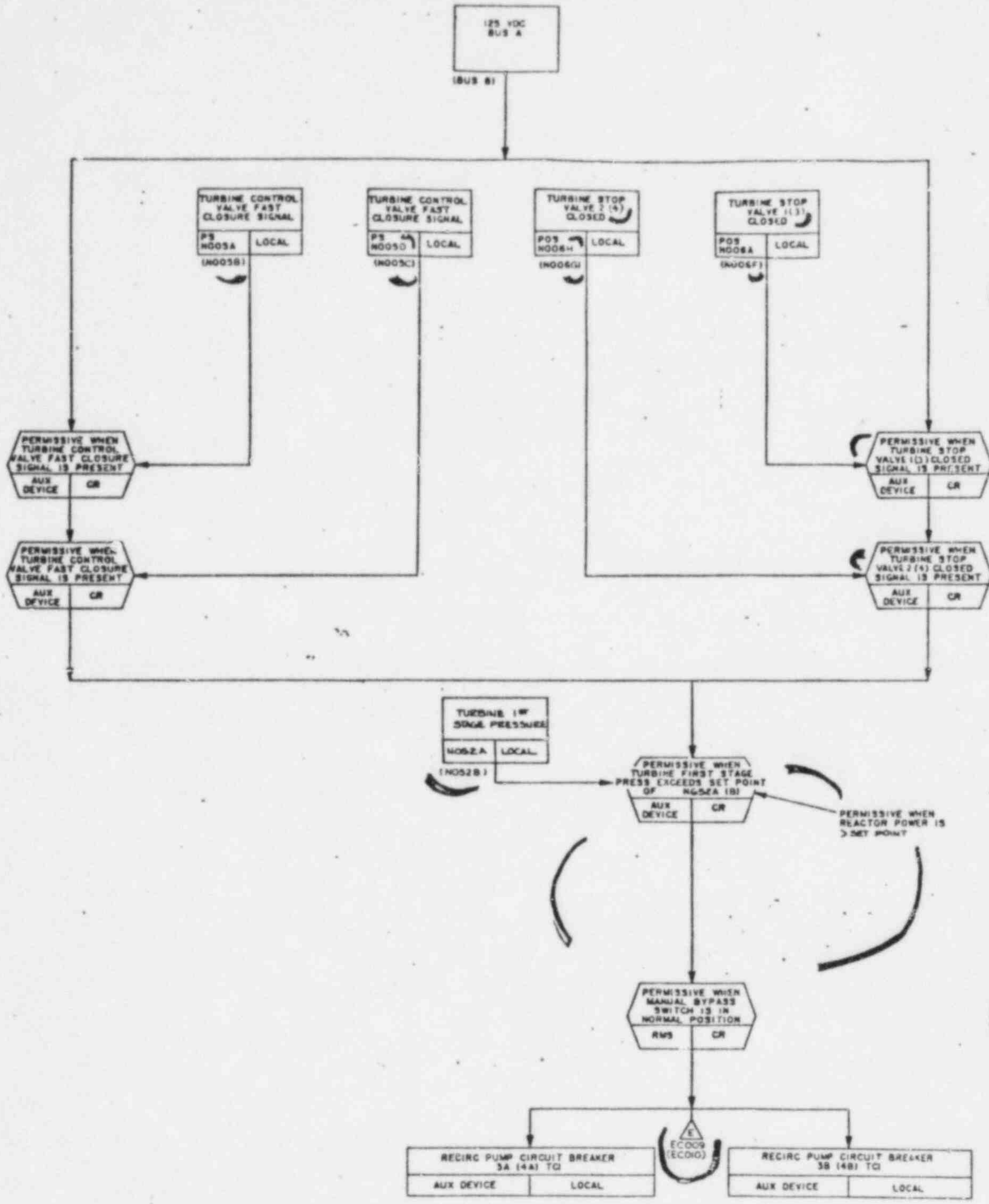


Also Available On Aperture Card

PRC APERTURE CARD

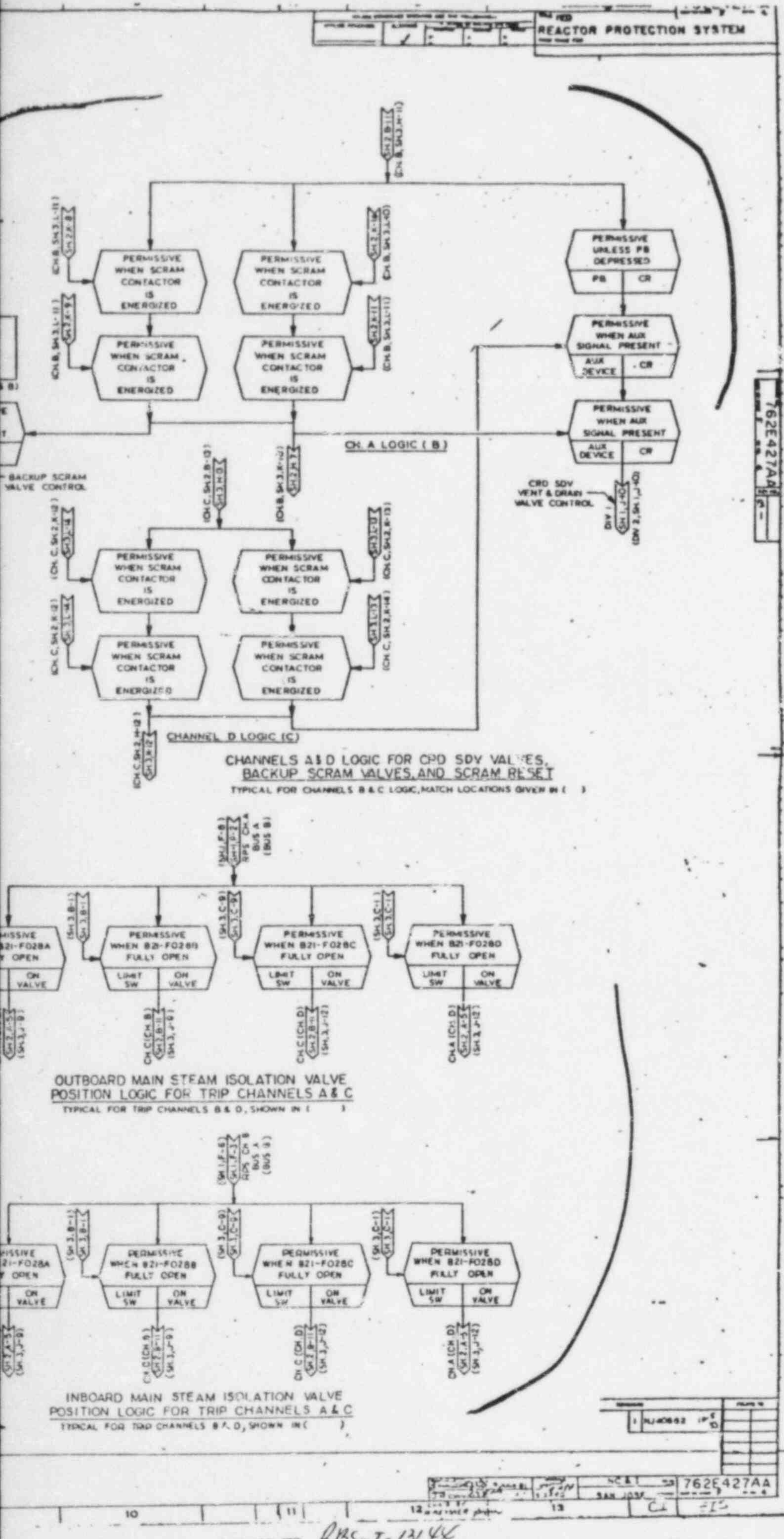
ATTACHED TO: RBS-T-13644

Nuclear Document Ctr 8312290277-03



RECIRC PUMP TRIP LOGIC A

TYPICAL FOR LOGIC B, SUFFIXES SHOWN IN ( )



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Aperture Card

PRC
APERTURE
CARD

ATTACHED TO: RBS-T-13644

Nuclear Document Control

8312290277-04

QUESTION 421.014 (7.2, 7.3, 7.4, 7.5)

Provide an evaluation of the effects of high temperatures on reference legs of water level measuring instruments subsequent to high-energy line breaks, including the potential for reference leg flashing/boil off, the indication/annunciation available to alert the control room operator of erroneously high vessel level indications resulting from high temperatures, and the effects on safety systems actuation (e.g., delays).

RESPONSE

~~The response to this request will be provided by September 1983~~.

REPLACE WITH INSERT

INSERT (for Pg. Q&R 7.2-2)

A comprehensive report discussing the effects of high temperatures on water level reference legs for BWR water level instrumentation has been submitted to the NRC Staff for review by the BWR Owners' Group. The report is entitled "Review of BWR Reactor Vessel Water Level Measurement Systems" and is identified as S. Levy Report No. SLI-8211. River Bend Station endorses the content and findings of this report where applicable to the design of RBS Unit 1.

The following design features are implemented at River Bend Station to improve control room operator and safety system response where accurate reactor vessel water level measurements are required:

1) The vertical drop of the water level reference leg instrument lines does not exceed eighteen inches where the lines are subject to temperature excursions capable of causing erroneous readings. The area of primary concern for this design improvement is the drywell.

   RBS procedures shall delineate for operator information the maximum expected errors for water level measurements given the unlikely event of drywell heatup beyond normal ambient conditions.

2) Annunciation is provided in the main control room to alert the operator to potential or actual water level measurement anomolies owing to high reference/variable leg temperatures. The annunciator is synthesized from two, redundant, Class 1E instrument channels which monitor drywell temperature.

3) The control room operator is furnished with redundant, Class 1E reactor vessel water level instrument channels for two overlapping regions of the vessel. The first region covers water level over a wide range from the dryer down to near the top of the fuel zone. The second region overlaps the first but extends down to the bottom of the core region. This safety-related display instrumentation and other water level measurement readings are deemed sufficient to provide the operator with an accurate appraisal of reactor vessel water level.

4) ECCS initiating signals are generated from analog circuitry which provides a switching function. Water level instruments used for ECCS actuation are grouped according to range (narrow, wide, fuel zone, and high level-upset) and multiple channels (A, B, C, D). These allow individual instrument channels to be observed for proper operation. This design feature greatly reduces the possibility of either a failed channel being unnoticed or erroneous channel information being used for system actuation.

5) Reactor water level information from several sources within the main control room is monitored by the Safety Parameter Display System (SPDS). The SPDS will alert control room operators to

water level measurement anomolies should the situation arise. The SPDS performs this function by performing a channel check by comparing two or more channels for equivalence within a given error margin.

Additional information is provided in revised Section 7.5.1.1.2 and Appendix 1A, Item II.F.2.

channels to verify operability and variable level. All trip units display trip status, using an indicator light located on the trip unit.

7.5.1.1.2 Reactor Water Level

REPLACE WITH INSERT

~~Two wide range water level signals are transmitted from two independent differential pressure transmitters and are recorded on two, two-pen recorders. One pen in each recorder records the wide range level, and the other pen records the reactor pressure. The range of the recorded level is from the top of the feedwater control range (just above the high level turbine trip point) down to a point near the top of the active fuel~~.

7.5.1.1.3 Reactor Pressure

Two reactor pressure signals are transmitted from two independent differential pressure transmitters and are recorded on two, two-pen recorders. One pen records pressure and the other pen records the wide range level. The range of recorded pressure is from 0 to 1,500 psig.

7.5.1.2 Reactor Shutdown Indication

The following information is provided to the main control room operator to monitor reactor shutdown.

1. Control rod status lights indicate each rod fully inserted. Control rod scram pilot valve position status lights indicate open valves.

2. Neutron monitoring power range channels and recorders downscale. The power sources are from
7 RPS MG sets. A loss of offsite power would result in all scram valve solenoids being deenergized and reactor scram.

3. Annunciators and indicators for RPS variables and trip logic in the tripped state.

4. The process computer provides logging of trips and control rod position and provides thermal-hydraulic information to the operator which he uses to keep the plant operating within technical specification limits. Redundant capability exists in case of process computer failure. The power source for the process computer is a Normal UPS.

INSERT (for Pg. 7.5-2)

Reactor water level information is obtained from physically and electrically separated differential pressure (dp) instrumentation. A cold reference leg design is utilized for RBS with a minimum amount of elevation change inside the drywell to minimize instrument channel error. The dp instruments operate an analog current loop which transmits level information to the main control room. Table 7.5-1 identifies reactor water level displays.

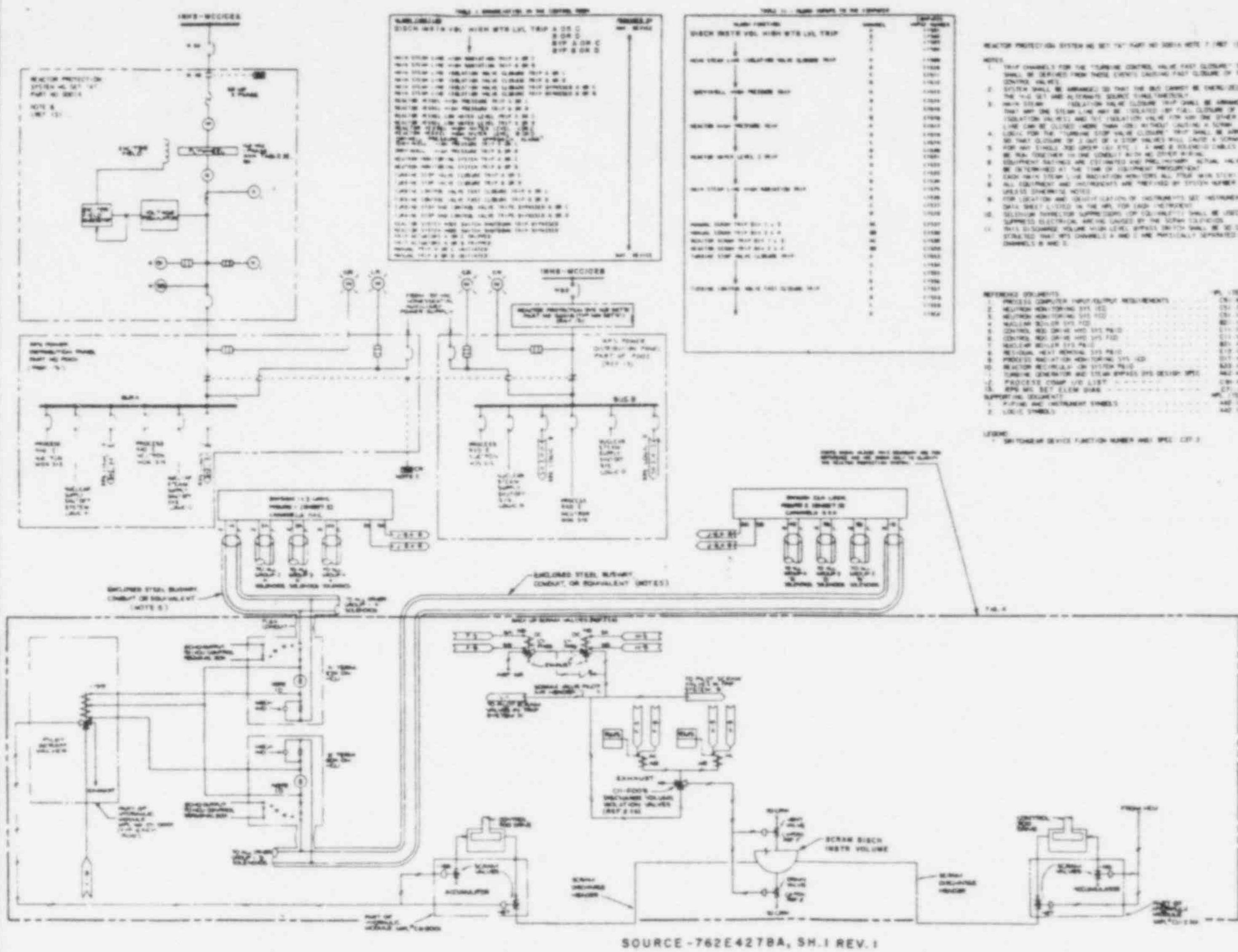
ENCLOSURE 12

QUESTION 421.016 (7.2)

During an earlier review (Hatch Unit 2), the staff questioned the adequacy of protection afforded the Class 1E RPS against possible sustained overvoltage or undervoltage conditions from the non-Class 1E RPS power supply. Several similar plants (i.e., Perry and Grand Gulf) have provided an electrical protection assembly (EPA) between the RPS and its power sources. No reference to the EPA could be found in Chapter 7 or 8 of the River Bend FSAR. State whether the River Bend design will incorporate an EPA between the RPS and its power sources. If so, the FSAR should be modified accordingly. If not, describe how the RPS is protected from degraded voltage and frequency conditions.

RESPONSE

The response to this request is provided in revised Sections 7.2.2.2 and 8.3.1.1.3.8.1. A revised Figure 7.2-1 showing the EPA ~~will be~~ is provided.~~by September 1983.~~



REPLACE

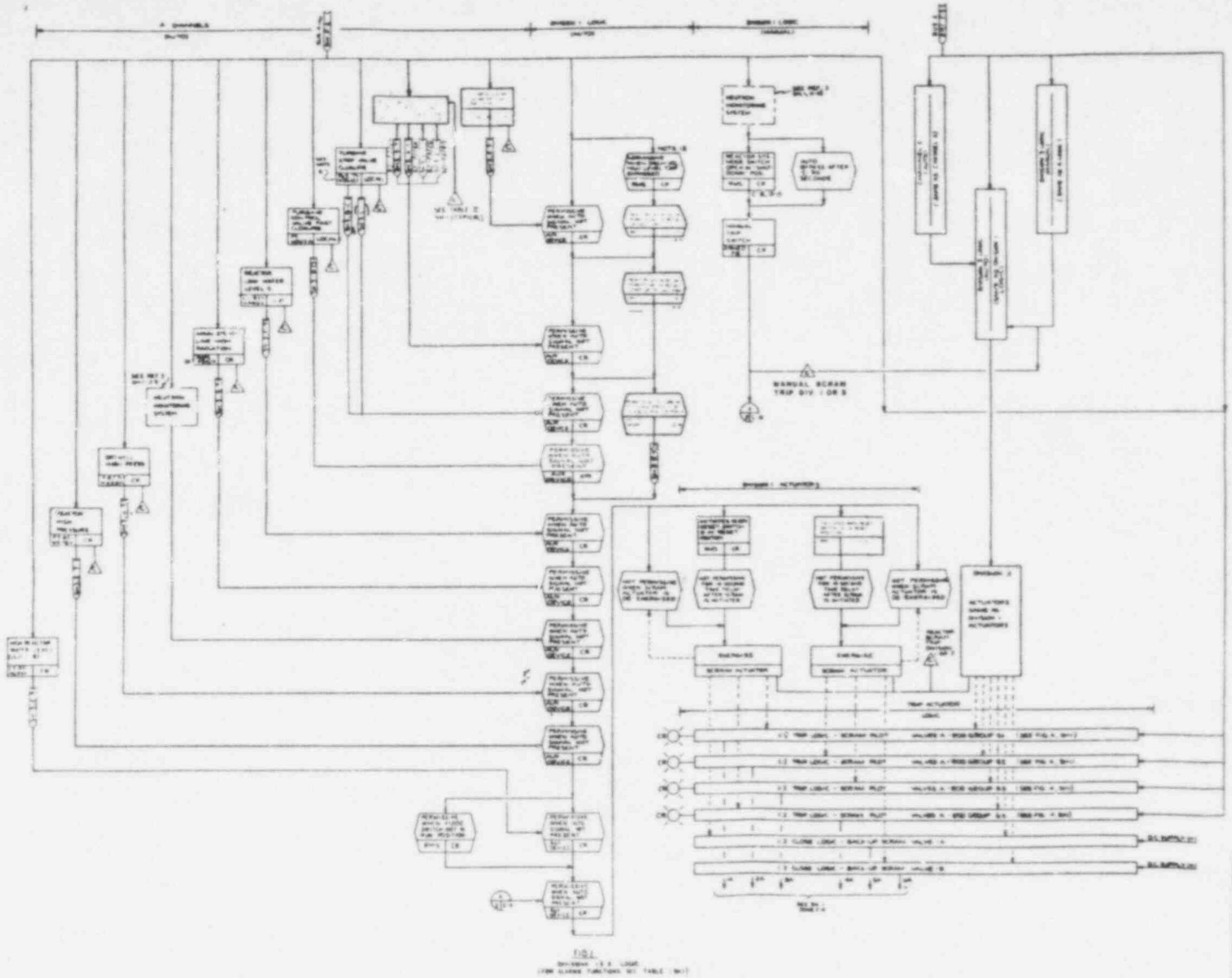
WITH REVISED DWG.

FIGURE 7.2-1

REACTOR PROTECTION SYSTEM INSTRUMENT AND ELECTRICAL DIAGRAM SHEET 1 OF 4

RIVER BEND STATION

FINAL SAFETY ANALYSIS REPORT



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REPLACE

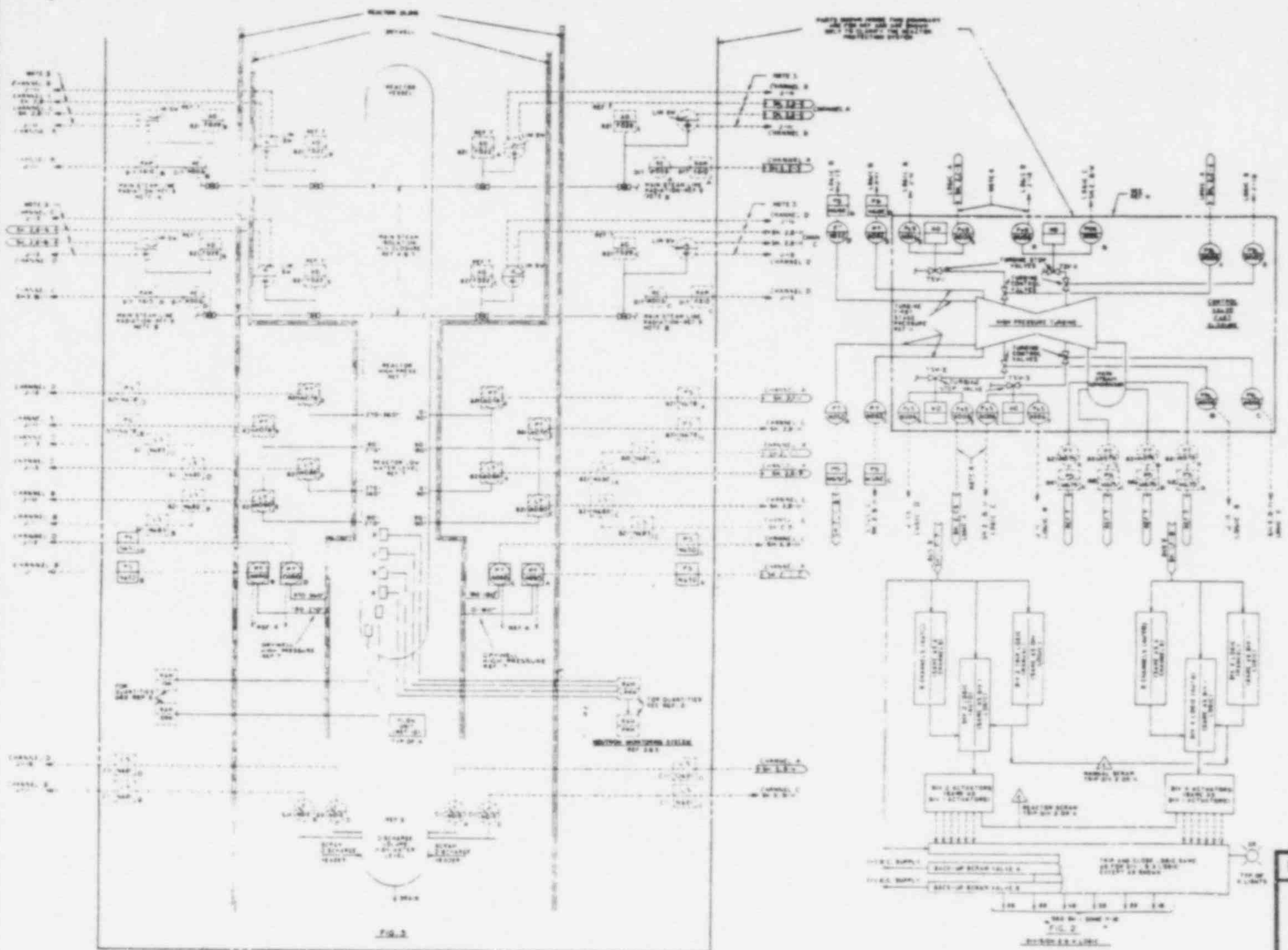
WITH

REVISED DWG.

FIGURE 7.2-1

REACTOR PROTECTION SYSTEM
INSTRUMENT AND ELECTRICAL
DIAGRAM SHEET 2 OF 4

RIVER BEND STATION
FINAL SAFETY ANALYSIS REPORT



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REPLACE

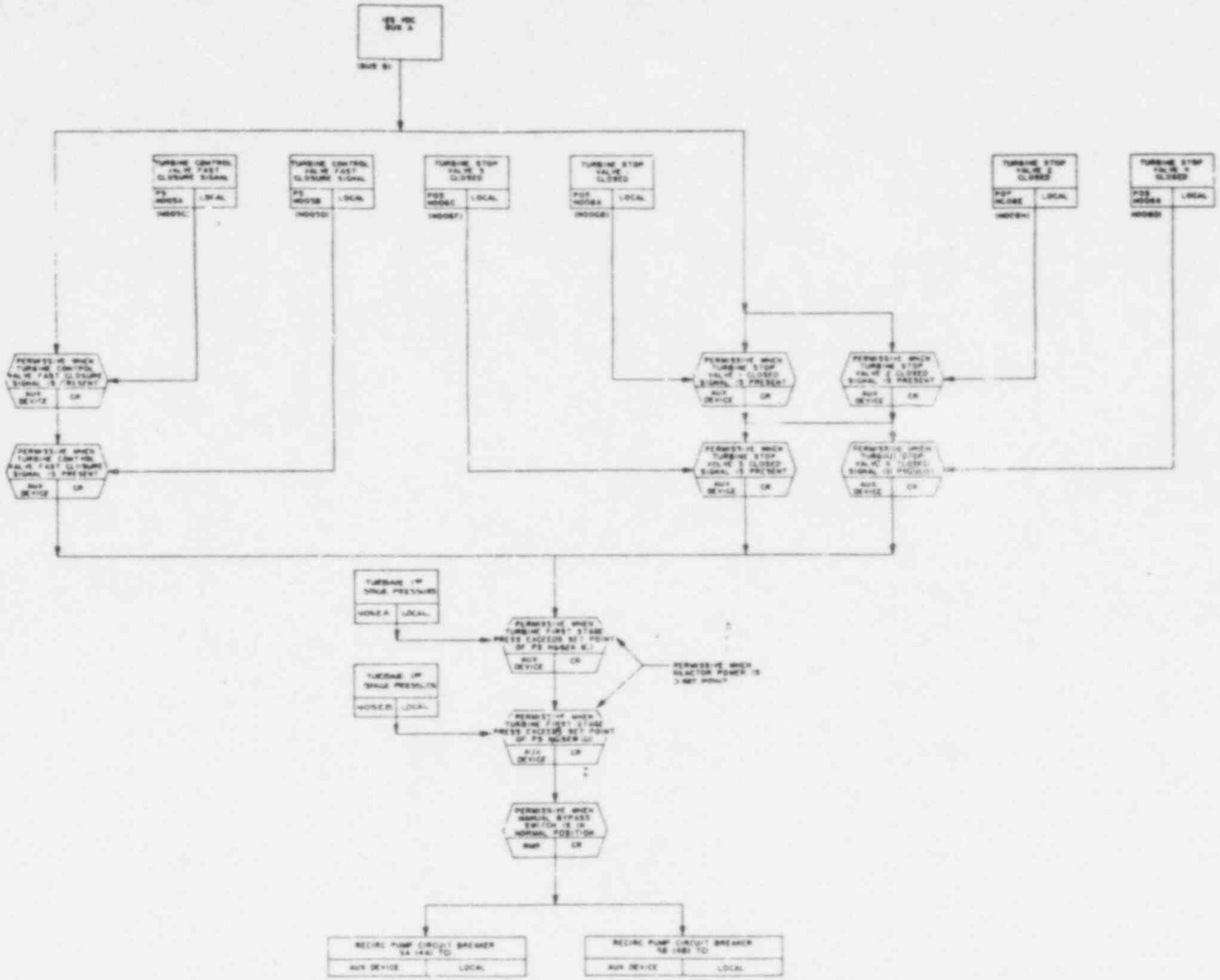
WITH

REVISED DWG.

FIGURE 7.2-1

REACTOR PROTECTION SYSTEM INSTRUMENT AND ELECTRICAL DIAGRAM SHEET 3 OF 4

RIVER BEND STATION
FINAL SAFETY ANALYSIS REPORT



RECIRC PUMP TRIP LOGIC A

SOURCE-762E427BA, SH. 4, REV. 1

REPLACE

WITH

REVISED DWG.

FIGURE 7.2-1

REACTOR PROTECTION SYSTEM
INSTRUMENT AND ELECTRICAL
DIAGRAM SHEET 4 OF 4

RIVER BEND STATION
FINAL SAFETY ANALYSIS REPORT

ENCLOSURE 13

QUESTION 421.017 (7.2, 7.3)

Provide and describe the following information for NSSS and BOP safety-related set points:

(a) Provide a detailed discussion and/or reference to the methodology used in determining safety system set points.

(b) Discuss any differences between the referenced methodology and the methodology used for River Bend.

(c) Verify that environmental error allowances are based on the highest value determined in qualification testing or identify and provide adequate justification for each exception.

(d) Identify any time limits on environmental qualification of instruments used for trip, post-accident monitoring or engineered safety features actuation. Where instruments are qualified for only a limited time, specify the time and basis for the limited time.

RESPONSE

~~The response to this request will be provided by September 1983.~~

REPLACE WITH INSERT

INSERT (for Pg. Q&R 7.2-5)

The response to this request for BOP safety-related set points is as follows:

(a), (b) The methodlogy used in determining safety system set points is in accordance with Regulatory Guide 1.105, Revision 1 and IEEE 279-1971. See Table 1.8-1 for the River Bend Station position on Regulatory Guide 1.105.

The balance of plant (BOP) safety-related set points are established based on the following:

1. A process safety limit (PSL) or safety limit is selected to maintain the integrity of physical barriers or other plant characteristics which must remain intact or operational. A safety factor or allowance is incorporated into the safety limit value.

2. A limiting safety system setting (LSSS) is established by providing an allowance between the PSL and the LSSS equal to (as a minimum) instrumentation inaccuracies such as:

   - Instrument inaccuracies
   - Power supply affects
   - Seismic effects
   - Environmental effects (temperature, radiation, etc.)
   - Calibration effects

   In calculating components inaccuracies, it is assumed that component errors are additive, and therefore system inaccuracy is the sum of component inaccuracies.

3. Set points are chosen such that the LSSS is not exceeded, taking into account tolerances for drift and adjustability. Additional allowance to account for uncertainties in analysis is provided where possible.

(c) The LSSS takes into account environmental error allowances as required based on qualification testing and other sources of design data. Where worst case data is not available conservative engineering estimates are used until verified data is obtained to validate or revise same. The present set points are based on qualification data and, therefore, no exceptions are taken at the present time.

(d) The qualification times for each piece of equipment are referenced or included in the Environmental Qualification Document (EQD). The EQD includes status and basis information and may be reviewed by the Staff at any time as required.

The response to this request for NSSS safety-related set points will be provided by the end of January, 1984. Gulf States is participating in a Licensing Review Group program for resolution of the Staff's request.

ENCLOSURE 14

QUESTION 421.018 (7.2, 7.3, 7.4)

Identify any sensors or circuits used to provide input signals to the protection systems which are located or routed through non-seismically qualified structures. This should include sensors or circuits providing input for reactor trip, emergency safeguards equipment such as the Emergency Core Cooling System, and safety-grade interlocks. Verification should be provided that the sensors and circuits meet IEEE 279 and are seismically and environmentally qualified. Of particular concern is the instrumentation relied upon to transfer RCIC and HPCS pump suction from the CST to the suppression pool.

RESPONSE

~~The response to this request will be provided by September 1983.~~

REPLACE WITH INSERT

INSERT (for Pg Q&R 7.2-6)

The condensate storage tank (CST) level instrumentation used to initiate HPCS and RCIC pump suction transfer from the CST to the suppression pool is located in a seismic Category I area. Refer to Sections 7.3.1.1.1.1 Item 2 and 9.2.6.3 for further information. The protection of this instrumentation from cold weather is discussed in the response to Question 440.20 and 410.63.

The Reactor Protection System (RPS), Reactor Recirculation System (RCS), and the Rod Control and Information System (RCIS) have Class 1E, fail-safe instrument channels originating in the turbine building which is a non-seismic Category I structure. The sending instruments are identified as follows:

Insturment No. (GE MPL)	Associated System
C71-N005A thru D (Turbine Control Valve Fast Closure)	RPS, RCS
C71-N006A thru H (Turbine Stop Valve Closure)	RPS, RCS
C11-N054A thru D (First Stage Turbine Pressure)	RCIS
B21-N075A thru D (Main Condenser Vacuum)	CRVICS
B21-N076A thru D (Main Steam Line Pressure)	CRVICS
C71-N052A thru D (First Stage Turbine Pressure)	RCS

The subject instrument channels are classified as Class 1E in the function that each performs. The components associated with each channel are qualified in accordance with the River Bend Station equipment qualification program.

All of the subject channels are designed to fail in a safe condition. the circuitry opens a contact to perform its safety function. Wiring for these instrument channels is routed in rigid metallic conduit for protection and to avoid inadvertent connection of the subject channels to a low or medium voltage power source.

The design of the wiring and instrument layout in the Turbine Building area for these instrument channels is such that no single, credible event can degrade the ability of the RPS, RCS, or RCIS to perform its safety function. An analysis for the effects of a 480V AC hot short on any RPS channel has been performed and confirms that no safety functions are lost as a result. River Bend Station does not consider this event to be credible.

ENCLOSURE 15

QUESTION 421.021 (7.2)

The discussion on Scram Discharge Instrument Volume (SDIV) Water Level, FSAR Section 7.2.1.1, states that four pressure (level) transmitters sense SDIV level and provide inputs to the RPS. However, Section 4.6.1.1.2.4.2.5 states that both float sensing and pressure (level) sensing devices are used for the automatic scram function. Resolve this apparent discrepancy.

RESPONSE

The response to this request is provided in revised Sections 7.2.1.1, Item 2.h, and 4.6.1.1.2.4.2.5. A revised Figure 7.2-1 ~~will be~~ is provided ~~by September 1983~~.

Note: Revised Fig. 7.2-1 is provided with the response to Question 421.016.

ENCLOSURE 16

QUESTION 421.022 (7.3,7.4)

It has been noted during past reviews that pressure switches or other devices were incorporated into the final actuation control circuitry for large horsepower safety-related motors which are used to drive pumps. These switches or devices preclude automatic (safety signal) and manual operation of the motor/pump combination unless permissive conditions, such as lube oil pressure, are satisfied. Accordingly, identify any safety-related motor/pump combinations which are used in the River Bend design that operate as noted above. Describe the pressure switches or other permissive devices used, the potential for failure (including common mode failure) of these devices to preclude safety functions, and the capability provided for testing these devices.

RESPONSE

The response to this request ~~will be provided by September 1983~~. is provided in the response to Q430.49 and in revised Section 8.3.1.1.6.2.

obtained, accelerating times on the order of 3 sec are achievable on centrifugal pumps.

8.3.1.1.6.2 Temperature Monitoring and Circuit Protection

The nature of Class 1E electrical equipment is such that
5 protection of the equipment is secondary to accident
mitigation and safe shutdown of the plant. Temperature
monitors and overload heaters are set only to alarm on
overload/overtemperature conditions during operation of
Class 1E equipment. Trip circuits actuate only to prevent
catastrophic failure which could augment rather than
mitigate an undesirable circumstance. Coordination
calculations show that protective devices actuate at the
lowest level necessary to isolate a fault. All protective
devices are set for a minimum of 125 percent of the full
5 load current rating of the equipment at all Class 1E voltage
levels. No cascading of protective devices has been
employed. See also Section 8.3.1.1.4.2 regarding HPCS
circuit protection.

The River Bend Station design has been reviewed to identify any large horsepower (rated 100 hp or more) safety-related motor/pump combinations that have pressure switches or other permissive devices incorporated into the final actuation control circuitry. These motors and permissive devices, along with the redundancy and diversity provided for such devices, are discussed in the following paragraphs.

1. High-Pressure Core Spray System (E22)

   The HPCS pump does not start if the undervoltage trip on
   the emergency bus is tripped. Redundant undervoltage
5 devices monitor bus voltage so that failure of one
   device to detect available HPCS power on the bus does
   not prevent the motor from starting.

   Certain protective trips can inhibit a HPCS DG start under test conditions; however, all but two of the DG trips are bypassed in the presence of an emergency start signal. The two exceptions are the overspeed trip and the generator differential device trip which protects the diesel generator. These devices are capable of being tested during normal operation.
   Although redundancy of certain components is applied within HPCS in order to improve reliability, the overspeed and differential trips are not redundant by component. The ECCS network is redundant by system.

2. Residual Heat Removal System (E12)

   There are no pressure switches capable of inhibiting a manual or automatic start of the RHR system. The RHR pump motor switchgear receives a stop signal if either the F004B or F066B valve is full open <u>and</u> the F006B, F009, or F007 is not fully open. Limit switches which sense the full open valve position and generate appropriate full open permissive are not redundant. The ECCS network is redundant by system and can tolerate loss of an entire RHR train.

3. Service Water System (SWP)

   Emergency start of service water pumps 1SWP*P2A and 1SWP*P2B is inhibited if the respective discharge valve 5
   is not fully closed or the standby service water initiation signal is not present.

   The limit switch sensing the full closed valve position to generate the appropriate full closed permissive is not redundant. However, redundancy does exist at the system level. The standby service water initiation signal is either reactor plant component cooling water loop loss of pressure or normal standby service water loop loss of pressure. Each loop is provided with four pressure sensors. One-out-of-two-taken-twice logic is used in generating the start permissive, thus providing adequate redundancy.

INSERT

8.3.1.1.6.3 Interrupting Capacity of Switchgear and Other Protective Devices

Fault current available at all voltage levels has been restricted to values within the certified rating of the interrupting devices employed at that level. All possible sources of fault current contributions have been considered, including abnormal sources such as an emergency diesel generator on test. Calculations of available short circuit currents are in accordance with ANSI C37.00-1964.

8.3.1.1.6.4 Grounding

The balance-of-plant and Class 1E Divisions I and II, both onsite and offsite, power distribution systems are low-resistance grounded.

Discussion of grounding on the HPCS power supply (ESF Division III) is covered in Section 8.3.1.1.4.2.

INSERT (for Pg. 8.3-30a)

The ability of the standby service water system to accommodate any single component failure without affecting safe shutdown or cooldown or post accident heat dissipation is detailed in Section 9.2.7.3 and the FMEA. As for common mode failures, these devices are qualified in accordance with Regulatory Guide 1.89. During shutdown, each pump can be verified to start automatically, on a pressure test signal to the pressure transmitters, to maintain service water pressure greater than technical specification requirements.

ENCLOSURE 17

QUESTION 421.023 (7.3)

During our review, it has become apparent that the logic for manual initiation for several Engineered Safety Feature (ESF) systems is interlocked with permissive logic from various sensors. In some cases it appears that the permissive logic is dependent upon the same sensors as those used for automatic initiation of the system. The staff's position is that the capability to manually initiate each safety system should be independent of permissive logic, sensors, and circuitry used for automatic initiation of that system such that a single failure will not prevent the initiation of a protective function by both automatic and manual means (see Section 4.17 of IEEE-279). Identify each safety system at River Bend which is interlocked as described above and provide proposed modifications or justification for the existing-design.

RESPONSE

~~The response to this request will be provided by September 1983.~~

REPLACE WITH INSERT

INSERT (for Pg. Q&R 7.3-4)

Balance of plant ESF system interlocks which are common to both manual and automatic initiation circuits are provided for protection of seven safety-related systems. However, in each case redundant equipment of a different Class 1E power source division is available in the other division such that no single failure in the manual, automatic, or common portion of the protection system prevents initiation by manual or automatic means of the system function.

Of the NSSS ESF systems, the HPCS, LPCS, LPCI, and ADS subsystem of ECCS share permissive logic between automatic and system-level manual initiation logic. Only the HPCS shares permissive logic between automatic and component-level (switch for injection valve control only) initiation.

The design is acceptable since the individual subsystems of ECCS are not required to meet the single failure criterion. The ECCS function is met with one of its subsystems inoperative.

ENCLOSURE 18

QUESTION 421.024 (7.3)

It appears that the ADS solenoid valves and associated circuitry cannot be tested with the plant at power. Provide plans for the testing of these valves and circuits or provide justification for the existing design. Identify all other ESF systems where either a portion of the actuation circuitry or an actuation device cannot be tested during reactor power operation.

RESPONSE

~~The response to this request will be provided by September 1983.~~

The response to this request for the ADS is provided in Section 7.3.2.1.3 under the discussion of Regulatory Guide 1.22 and revised Section 7.3.1.1.1.2.

There are no other ESF systems where either a portion of the actuation circuitry or an actutation device cannot be tested during reactor power operation.

2. ADS Operation

Schematic arrangements of system mechanical equipment and operator information displays are shown in Fig. 5.1-3. ADS component control logic and operator information displays are shown in Fig. 7.3-2. Instrument location drawings and elementary diagrams are identified in Section 1.7.

The ADS consists of two redundant and independent trip systems, trip systems A and B. ADS trip system A actuates the A solenoid air pilot valve on each ADS SRV. Similarly, ADS trip system B actuates the B solenoid air pilot valve on each ADS SRV. Actuation of either solenoid pilot valve causes the ADS SRV to open and provide depressurization. To prevent inadvertent actuation of the ADS, two channels of logic for each ADS trip system (A and B) are used. Both channels must be activated to actuate an ADS trip system.

Each trip channel contains a single input from a drywell high pressure transmitter. One trip channel includes two differential pressure sensor inputs monitoring reactor vessel low water level (trip levels 1 and 3). The low water level 3 trip provides confirmation of a reactor vessel low water level condition. The second trip channel is redundant, except the low water level confirmation signal is omitted.

To assure that adequate makeup water is available after the vessel has been depressurized, each trip channel includes a pump discharge pressure permissive signal indicating LPCI or LPCS system available for vessel water makeup. Any one of the three LPCI pumps or the LPCS pump available for reactor coolant makeup is sufficient to permit automatic depressurization (one pump each per trip system).

105-second

After receipt of the initiation signals and after a delay provided by timers, each of the two solenoid air pilot valves is energized. This allows pneumatic pressure from the accumulator to act on the air cylinder operator. Each ADS trip system has a time delay that can be reset manually ~~to delay system initiation.~~ The time delay is selected to be within a period that allows the HPCS to perform its function prior to ADS initiation. In the event of HPCS failure, the time delay period is selected to allow initiation of ADS, LPCI, and LPCS in time to maintain the fuel barrier temperature within acceptable limits. If reactor vessel water level is restored by HPCS prior to the end of the time delay, ADS initiation is prevented.

INSERT A

INSERT B

by activating the timer reset buttons

INSERT A (for Pg. 7.3-5)

Resetting the ADS timers does not change the state of the initiating circuits. It merely extends the time delay before the ADS function takes place.

INSERT B (for Pg. 7.3-5)

The operator is procedurally constrained from repeatedly resetting the timers and would base his decision on information provided by safety-related displays: e.g., reactor pressure, reactor water level, and water inventory make-up system performance. In addition, he would have the HPCS, RCIC and feedwater systems at his disposal to provide make-up water.

operability of each system component. Testing of safety-related sensors is accomplished by valving out each sensor, one at a time, and applying a test pressure source. The main steam line radiation sensors may be removed and test sources applied. The combustible gas control system sensors are tested by introducing sample gases of known analysis. This verifies the operability of the sensor and the associated logic components in the main control room. Functional operability of temperature sensors may be verified by readout comparisons, applying a heat source to the locally mounted temperature sensing elements, or by continuity testing.

For the HPCS, LPCS, and LPCI, testing for functional operability of the control logic relays can be accomplished by use of plug-in test jacks and switches in conjunction with single sensor tests.

REPLACE WITH INSERT

~~Four test jacks are provided to allow ADS logic testing (one for each logic channel). During testing, only one logic should be actuated at a time. However, when the test plug is plugged into one channel, the complement channel of that trip system is automatically rendered inoperative. Therefore, inadvertent ADS actuation cannot occur even if both channels are improperly placed in the test mode simultaneously. An alarm is provided if a test plug is inserted in both channels in a division at the same time. Operation of the test plug switch and the permissive contacts closes one of the two series relay contacts in the valve solenoid circuit. This causes a panel light to come on indicating proper channel operation.~~

Annunciation is provided in the main control room whenever a test plug is inserted in a jack to indicate to the operator that an ECCS is in a test status.

Operability of air-operated, solenoid-operated, and motor-operated valves is verified by actuating the valve control switches and monitoring the position change by position indicating lights at the control switch.

The ESF systems are provided with indications, status displays, annunciation, and computer printouts which aid the main control room operator during periodic system tests to verify component operability.

3. Regulatory Guide 1.40

See Section 1.8

INSERT (for Pg. 7.3-45)

Four test jacks are provided to allow ADS logic testing (one for each logic channel). The logic circuits are designed to allow the system testing without actually opening any of the ADS valves. During testing, to prevent opening of the ADS valve, one of each pair of complimentary logic channels A&E or B&F is activated by a test switch inserted into the logic panel in the main control room. When the test plug is inserted into one channel, the complement channel of that trip system is automatically rendered inoperative. Therefore, inadvertent ADS actuation cannot occur even if both channels are improperly placed in the test mode simultaneously. An alarm is provided if a test plug is inserted in both channels in a division at the same time. Operating the test switch through each of its positions in combination with operation of the trip units, allows verification of the proper ADS logic response by observing indicating lamps and activation of annunciator windows. The final ADS valve initiating logic is verified by neon lamps connected across series logic contacts which allow verification of operation without actually operating the associated solenoid pilot valve.

ENCLOSURE 19

QUESTION 421.026 (7.3)

In the discussion of the High Pressure Core Spray (HPCS) System, Section 7.3.1.1.1.1, the statement is made that the HPCS provides makeup water to the reactor until the vessel water level reaches the high level trip (trip level 8) and there is no high drywell pressure signal present. The high drywell pressure interlock has been removed in other BWR HPCS designs since the potential exists for flooding of the steam lines and subsequent damage to safety-related valves and primary system piping. State whether the River Bend design will be modified to eliminate this interlock. If so, revise the FSAR and associated drawings accordingly.

RESPONSE

The response to this request is provided in the response to Question 440.36.

QUESTION 440.36 (6.3)

An electrical interlock is incorporated into the HPCS circuitry that prevents the injection valve from closing automatically upon receipt of the high reactor water level (L8) signals if a high drywell pressure signal still exists. The interlock was added as a result of the NRC staff review of GESSAR-238, which indicated that the interlock was needed to assure diversity of HPCS initiation signals and to prevent premature HPCS termination. However, flooding of the steam lines could result in damage to the safety/relief valves and primary system piping unnecessarily, since the interlock tends to keep the HPCS in operation past the point of reflooding the core and does not significantly add to the overall safety. We require justification for use of the present logic or removal.

RESPONSE

GSU endorses the LRG-II issue 13-RSB which states the electrical interlock will be removed. This modification allows the HPCS flow to be shutoff at high reactor vessel water level (level 8) when a high drywell pressure signal is present and prevents the flooding of the steam lines if the vessel is overfilled. ~~An FSAR amendment will be provided to reflect this modification when the design change is complete.~~

This is reflected in revised Sections 6.3.2.2.1 and 7.3.1.1.1.1 and in revised Figure 7.3-1.

The HPCS pump discharge flow and pressure are monitored by pressure switches. If pump discharge pressure is normal but discharge flow is low enough that pump overheating may occur the minimum flow return line valve MO F012 is signaled to open. The valve is automatically closed if flow is normal. The HPCS reaches its design flow rate within 27 sec following receipt of the initiation signal.

If the water level in the condensate storage tank falls below a predetermined level, the suppression pool suction valve MO F015 automatically opens. When MO F015 is fully open the condensate storage tank suction valve MO F001 automatically closes. Two level transmitters are used to detect low water level in the condensate storage tank. Either transmitter can cause automatic suction transfer. The suppression pool suction valve also automatically opens if high water level is detected in the suppression pool. Two level transmitters monitor suppression pool water level and either transmitter can initiate opening of the suppression pool suction valve. To prevent losing suction to the pump, the suction valves are interlocked so that one suction path must be open before the other closes.

The HPCS provides makeup water to the reactor until the vessel water level reaches the high level trip (trip level 8). ~~and there is no high drywell pressure signal present.~~ The injection valve MOF004 is then automatically closed and the pump continues to run on minimum flow recirculation. The injection valve automatically reopens if vessel level again drops to the low level (trip level 2) initiation point.

The HPCS pump motor and injection valve are provided with manual override controls. These controls permit the reactor operator to control the system manually following automatic initiation.

7.3.1.1.1.2 Automatic Depressurization System (ADS)

1. ADS Function

The ADS is designed to provide automatic depressurization of the reactor vessel by activating seven SRVs. These valves vent steam to the suppression pool in the event that the HPCS cannot maintain the reactor water level following a LOCA. ADS reduces the reactor pressure so that flow from the RHR-LPCI mode and LPCS can inject into the reactor vessel in time to cool the core and limit fuel barrier temperature. Refer also to Section 6.3.

the maximum differential pressure across the valve expected for any system operating mode including HPCS pump shutoff head. The valve opens within 12 sec following receipt of a signal to open provided power is available. This valve is normally closed to back up the inside testable check valve for containment integrity purposes. A test connection/drain line is provided between the two isolation valves and is normally closed with two valves to assure containment integrity.

Remote controls for operating the motor operated components and diesel generator are provided in the main control room. The controls and instrumentation of the HPCS system are described, illustrated, and evaluated in Section 7.3.1.1.

The system is designed to pump water into the reactor vessel over a wide range of pressures. For small breaks that do not result in rapid reactor depressurization, the system maintains reactor water level and depressurizes the vessel. For large breaks the HPCS system cools the core by a spray.

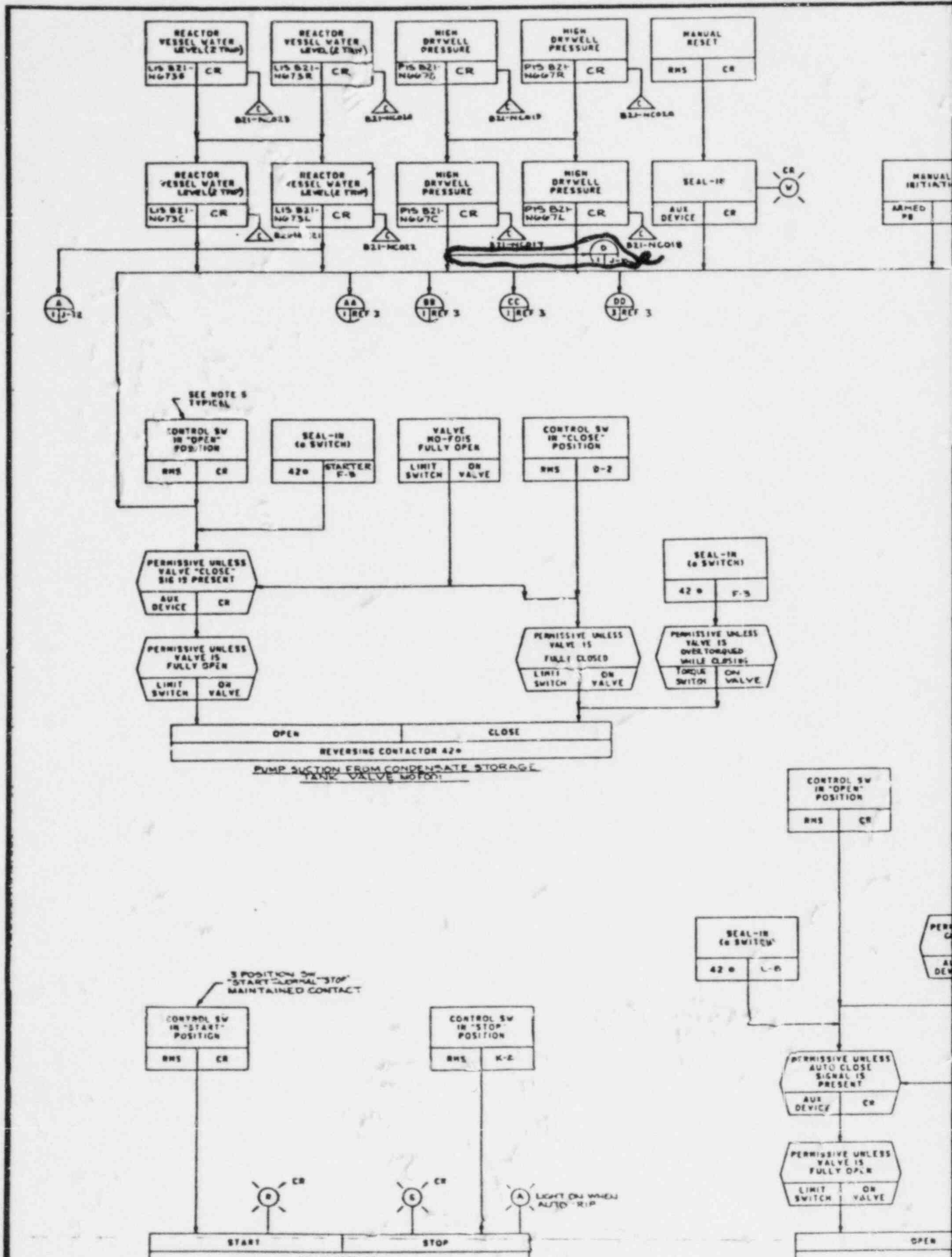
If a LOCA should occur, two signals indicating low water level or high drywell pressure initiate the HPCS and its support equipment. The system can also be placed in operation manually.

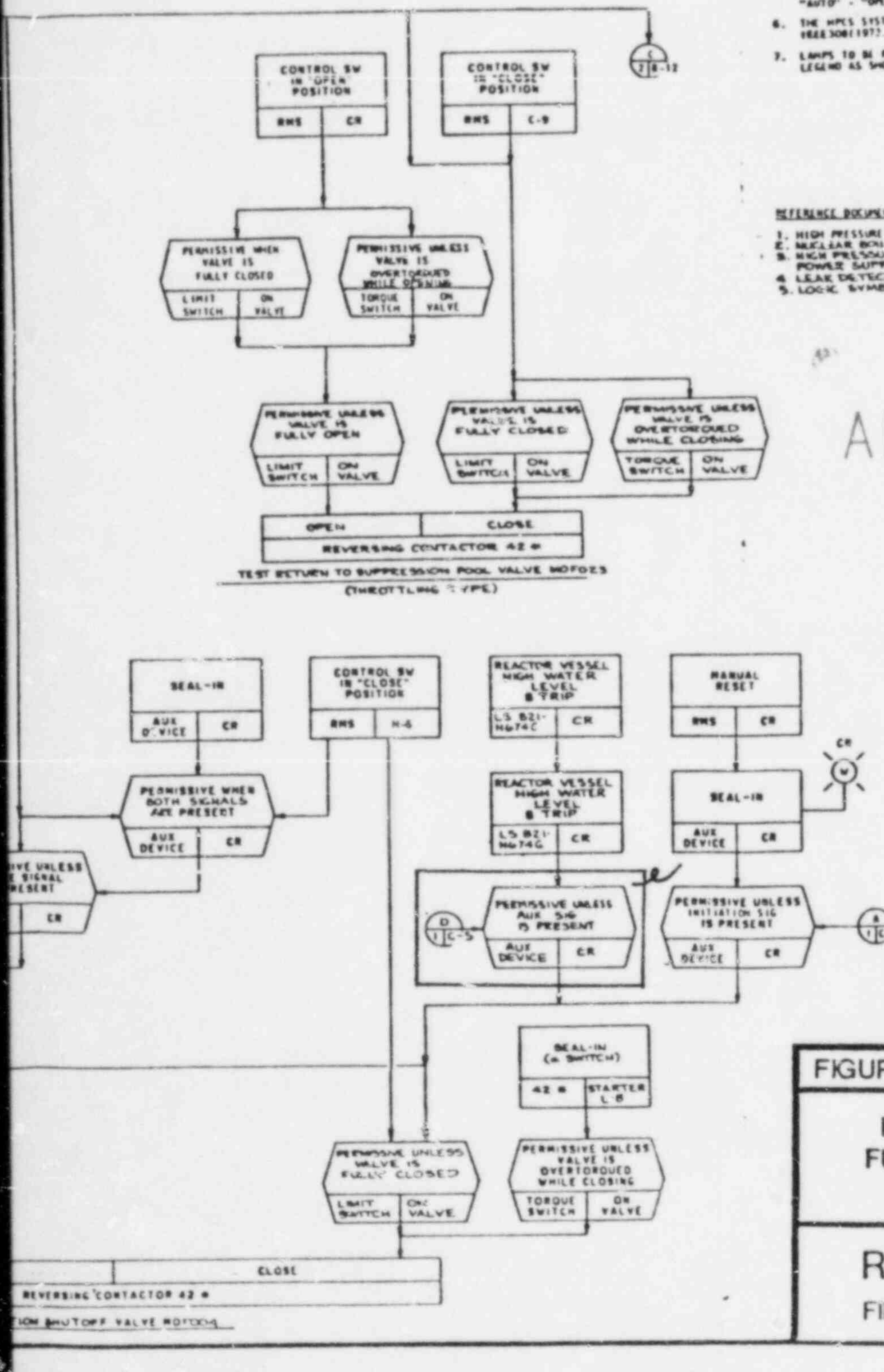
The HPCS system is capable of delivering rated flow into the reactor vessel within 27 sec following receipt of an initiation signal.

When a high water level in the reactor vessel is signaled, the HPCS is automatically stopped by a signal to the injection valve to close~~,~~ ~~unless a high drywell pressure signal exists. If a high drywell pressure signal exists in conjunction with a high reactor water level signal, HPCS injection continues until manually stopped~~. The HPCS system also serves as a backup to the RCIC system in the event the reactor becomes isolated from the main condenser during operation and feedwater flow is lost.

If normal auxiliary power is not available, the HPCS pump motor is supplied by its own diesel generator. The HPCS diesel generator is discussed in Section 8.3.

The HPCS pump head flow characteristics used in LOCA analyses are shown in Fig. 6.3-3. When the system is started, initial flow rate is established by primary system pressure. As vessel pressure decreases, flow increases. When vessel pressure reaches 200 psid (psid = differential pressure between the reactor vessel and the suction source)


REACTOR VESSEL WATER LEVEL(2 TRIP)
LIS B21-N073A
CR
REACTOR VESSEL WATER LEVEL(2 TRIP)
LIS B21-N073R
HIGH DRYWELL PRESSURE
PIS B21-N067G
HIGH DRYWELL PRESSURE
PIS B21-N067R
MANUAL RESET
RMS
SEAL-IN
AUX DEVICE
MANUAL INITIATION
ARMED PB
REACTOR VESSEL WATER LEVEL(2 TRIP)
LIS B21-N073C
REACTOR VESSEL WATER LEVEL(2 TRIP)
LIS B21-N073L
HIGH DRYWELL PRESSURE
PIS B21-N067C
HIGH DRYWELL PRESSURE
PIS B21-N067L
B21-N002
B21-N018
REF 3
SEE NOTE 5 TYPICAL
CONTROL SW IN "OPEN" POSITION
SEAL-IN (a SWITCH)
42a
STARTER F-B
VALVE MO-F015 FULLY OPEN
LIMIT SWITCH
ON VALVE
CONTROL SW IN "CLOSE" POSITION
D-2
PERMISSIVE UNLESS VALVE "CLOSE" SIG IS PRESENT
SEAL-IN (a SWITCH)
42 a
F-5
PERMISSIVE UNLESS VALVE IS FULLY OPEN
PERMISSIVE UNLESS VALVE IS FULLY CLOSED
PERMISSIVE UNLESS VALVE IS OVERTORQUED WHILE CLOSING
TORQUE SWITCH
OPEN
CLOSE
REVERSING CONTACTOR 42a
PUMP SUCTION FROM CONDENSATE STORAGE TANK VALVE MOTOR
CONTROL SW IN "OPEN" POSITION
SEAL-IN (a SWITCH)
42 a
L-B
3 POSITION SW "START-NORMAL-STOP" MAINTAINED CONTACT
CONTROL SW IN "START" POSITION
CONTROL SW IN "STOP" POSITION
K-2
PERMISSIVE UNLESS AUTO CLOSE SIGNAL IS PRESENT
PERMISSIVE UNLESS VALVE IS FULLY OPEN
LIGHT ON WHEN AUTO TRIP
START
STOP
CONTACTOR 42a
WATER LEG PUMP C003



NOTES:

1. A) PUMP-MOTOR COMBINATION STARTERS SHALL BE PROVIDED WITH THERMAL OVERLOADS WHICH TRIP ON OVERLOAD. BREAKERS SHALL PROVIDE SHORT CIRCUIT PROTECTION. TRIPPING OF EITHER TYPE OF DEVICE IS ANNUNCIATED VIA AN ALARM RELAY.

   B) VALVE MOTORS ARE TO BE PROVIDED WITH THERMAL OVERLOAD TRIPS. LOSS OF POWER ANNUNCIATOR, OVERLOAD TRIPS TO BE BYPASSED UNLESS VALVE UNDER TEST. IN ADDITION VALVE MOTOR CIRCUITS ARE TO BE PROVIDED WITH SHORT CIRCUIT CURRENT PROTECTIVE TRIPS.

2. ALL EQUIPMENT AND INSTRUMENTS ARE PREFIXED BY SYSTEM NUMBER E22 UNLESS OTHERWISE NOTED.

3. FOR ADDITIONAL ALARMS & PROCESS INSTRUMENTATION NOT SHOWN SEE REF. 1.

4. * SWITCHGEAR DEVICE FUNCTION NUMBERS ANSI SPEC C37.2.

5. UNLESS OTHERWISE NOTED ALL RMS SHALL BE 3 POSITION SWITCHES, "CLOSE" "AUTO" - "OPEN" SPRING RETURN TO "AUTO", FROM "CLOSE" - "OPEN".

6. THE HPCS SYSTEM SHALL BE DESIGNED IN ACCORDANCE WITH IEEE279(1971) & IEEE308(1971).

7. LAMPS TO BE PART OF LIGHT BOX LOCATED BELOW REGULAR HPCS ANNUNCIATOR LEGEND AS SHOWN.

REFERENCE DOCUMENTS	MPL ITEM NO.
1. HIGH PRESSURE CORE SPRAY P&ID	E22-101C
2. NUCLEAR BOILER SYSTEM P&ID	B21-1010
3. HIGH PRESSURE CORE SPRAY POWER SUPPLY FCD	E22-1040
4. LEAK DETECTION SYS. P&ID	E31-1010
5. LOGIC SYMBOL	A42-1030

PRC APERTURE CARD

Also Available On Aperture Card

SOURCE-851E892AA, SH. I, REV. I

FIGURE 7.3-1

HIGH PRESSURE CORE SPRAY FUNCTIONAL CONTROL DIAGRAM SHEET 1 OF 3

RIVER BEND STATION

FINAL SAFETY ANALYSIS REPORT

8312290277-05

ENCLOSURE 20

QUESTION 421.030 (7.6)

Demonstrate that the Safety/Relief Valve (SRV) low-low set point function is adequate given a single failure which could cause an additional SRV to open during the time for which only one valve is permitted to be open (i.e., on second and subsequent valve pops).

RESPONSE

The response to this request ~~will be provided by September 1983.~~ is provided in revised Section 7.6.1.8, Item B.2. This response is consistent with LRG-II Item 3-ICSB.

actuations allow pneumatic pressure from the accumulator to act on the air cylinder operator and open the valve.

Operation of the SRV is initiated by high reactor vessel pressure. Redundant reactor vessel pressure channels are provided in each trip system which operate in a two-out-of-two configuration in order to prevent inadvertent SRV actuation. Each trip system provides the following capabilities:

1. Initiate operation of three groups of SRVs at the respective pressure set points. This feature automatically adjusts the relief capacity to the size of the overpressure condition. The reclose pressure set point (reset) for any group is separately adjusted, and adequate deadband is provided to eliminate rapid open/close operation and minimize system stresses.

2. Alter set points on selected valves to minimize the number of valves that reopen following the initial pressure surge. ~~A low-low set logic is provided as part of each trip system, and is initiated when the middle set point discussed above is exceeded. The logic interacts in the above reactor vessel pressure channels to alter the set points on selected valves to provide three new groups of SRVs which operate at three different lower set point and reset values. The set points and resets, in general, are arranged to keep the selected valves open and reduce system pressure to lower valves, and, after closing, to reopen the selected valves at lower set points than those provided in 1 above. The low-low set logic is sealed in when initiated and must be manually reset.~~ INSERT

Manual system level initiation capability is included in each trip system. Remote manual switches are installed in the main control room. Lights in the main control room indicate when the solenoid-operated pilot valves are energized to open a safety relief valve.

7.6.1.9 Design Basis Information

The safety-related systems described in Section 7.6 are designed to provide timely protective action inputs to other safety systems to protect against the onset and consequences of conditions that threaten the integrity of the fuel barrier and the RCPB. Chapter 15 identifies and evaluates events that jeopardize the fuel barrier and RCPB. The

INSERT (for Pg. 7.6-18)

In order to assure that no more than one relief valve reopens following a reactor isolation event, six SRV valves are provided with lower opening and closing setpoints. These setpoints override the normal setpoints following the initial opening of the relief valves and act to hold these valves open longer, thus preventing more than a single valve from reopening subsequently. This system logic is referred to as the low-low setpoint relief logic and functions to ensure that the containment integrity is not threatened on subsequent ADS actuations. This logic is armed when two or more valves are signaled to open from their normal relief pressure switches. At this time, the low-low set logic automatically seals itself into control of the six selected valves and actuates the annunciator. This logic remains sealed in until manually reset by the operator.

Since the valves have already opened from their original pressure relief signals, the low-low set logic acts to hold them open past their normal reclose point until the pressure decreases to a predetermined "low-low" setpoint. Thus these valves remain open longer than the other safety/relief valves. This extended relief capacity assures that no more than one valve reopens a second time. Also, the sealed-in logic provides the low-low set valves with new reopening setpoints which are lower than their original safety/relief setpoints. The "medium" low-low set valve acts as a backup for the "low" low-low set valve, should it mechanically fail. See Section 5.2.2 for further system description.

The low-low set logic is designed with redundancy and single failure criteria, i.e., no single electrical failure (1) prevents any low-low set valve from opening, or (2) causes inadvertent seal-in of low-low set logic.

The six valves associated with low-low set are arranged in three independent secondary setpoint groups or ranges (low, medium, high). The "low" and "medium" pressure ranges consist of one valve each, having both "reopen" and "reclose" setpoints independently and uniquely adjustable. These are set considerably lower than their normal SRV setpoints. The remaining valves are individually controlled by new pressure switches which have an independently adjustable "reclose" setpoint. The normal SRV opening setpoints are slightly lower for this valve group though reclose is extended in the low-low set operating mode.

The pressure switches are arranged in two divisions for each low-low set valve. The single-failure criterion is thus met for this function.

The SRV system has two low-low setpoint logics, one in Division 1 and the other in Division 2. Either one can perform the low-low set function. Each valve has its own set of pressure switches. A key-locked switch which has a "Normal" and a "Test" position is provided for each division. The key is removable only in the "Normal" position. When the key is inserted and switched to "Test," an annunciator alerts the operator of the test status of that division. In the test mode, all of the valves except the specific one under test remain responsive to the high reactor pressure signals should they occur. Indicator lights are switched in series with the solenoid coils on the low-low set valve to facilitate logic testing

ENCLOSURE 21

QUESTION 421.031 (7.6)

Amend Section 7.6 of the FSAR to include a discussion on high pressure/low pressure interfaces and associated interlocks. Discuss how each of the high pressure/low pressure interfaces in your design conforms to the requirements of Branch Technical Position ICSB 3, "Isolation of Low Pressure Systems from the High Pressure Reactor Coolant System." Also, discuss how the associated interlock circuitry conforms to the requirements of IEEE 279. The discussion should include illustrations from applicable drawings.

RESPONSE

The response to this request ~~will be provided by September 1983.~~ is provided in revised Sections 7.3.1.1.1.3 and 7.3.1.1.1.4. This response is consistent with LRG-II Item 2-ICSB.

Once initiated the ADS logic seals in and can be reset by the main control room operator only when either drywell pressure or vessel water level returns to normal.

Two control switches (one for each trip system solenoid) are located in the main control room for each SRV associated with the ADS. Each switch controls one of the two solenoid air pilot valves.

7.3.1.1.1.3 Low Pressure Core Spray (LPCS)

1. LPCS Function

The purpose of the LPCS is to provide low pressure reactor vessel core spray following a LOCA when the vessel has been depressurized and vessel water level has not been restored by the HPCS. The LPCS is functionally diverse to the LPCI mode of the RHR system. See Section 6.3.

2. LPCS Operation

Schematic arrangements of system mechanical equipment and operator information displays are shown in Fig. 6.3-4. LPCS component control logic and operator information displays are shown in Fig. 7.3-3. Instrument location drawings and elementary diagrams are identified in Section 1.7.

The LPCS is initiated automatically by reactor vessel low water level and/or drywell high pressure. The system is designed to operate automatically for at least 10 min without any actions required by the main control room operator. Once initiated the LPCS logic seals in and can be reset by the main control room operator only when the initiating conditions return to normal. Refer to Fig. 7.3-3 for a schematic representation of the LPCS system initiation logic.

Reactor vessel water level (trip level 1) is monitored by two redundant level transmitters. Drywell pressure is monitored by two redundant pressure transmitters. The vessel level trip unit relay contacts and the drywell pressure trip unit relay contacts are connected in a one-out-of-two twice logic arrangement so that no single instrument failure can prevent initiation of LPCS.

INSERT →

The LPCS components respond to an automatic initiation signal simultaneously (or sequentially as noted) as follows:

1. The Division 1 diesel generator is signaled to start.

INSERT (for Pg. 7.3-6)

Additionally, a reactor low pressure permissive is provided in one-out-of-two twice logic before the injection valves are signalled to open. Manual initiation of the LPCS is provided, which bypasses the initiation logic except that the reactor low-pressure permissive must be present to open the injection valves. Reactor pressure is monitored by eight pressure sensors, four per division, mounted on racks in the reactor building. Division I provides the interlocks for the LPCS.

is designed to operate automatically for at least 10 min without any actions required by the main control room operator. Once initiated the LPCI logic seals in and can be reset by the main control room operator only when initiating conditions return to normal.

Reactor vessel water level (trip level 1) is monitored by two redundant differential pressure transmitters. Drywell pressure is monitored by two redundant pressure transmitters.

INSERT →

To initiate the Division II LPCI (Loops B and C) the vessel level trip unit relay contacts and the two drywell pressure trip unit relay contacts are connected in a one-out-of-two twice arrangement so that no single instrument failure can prevent initiation of LPCI.

The Division I LPCI (Loop A) receives its initiation signal from the LPCS logic.

The LPCI system components respond to an automatic initiation signal simultaneously (or sequentially as noted) as follows (the Loop A components are controlled from the Division I logic; the Loop B and C components are controlled from the Division II logic):

1. The Division II diesel generator is signaled to start from the Loop B and C initiation logic.

2. If normal auxiliary (offsite) power is available at the pump motor buses the LPCI Loop A, B, and C pumps are signaled to start. If offsite power is not available and the diesel generators are providing power to the pump motor buses, sequential loading of the diesel generators is required. This is accomplished by delaying the start of the LPCI pumps A and B by 5 sec while allowing the LPCS and LPCI C pumps to start immediately.

3. The normally open RHR injection valves MO F027A and MO F027B are signaled to open. When power is available at the associated pump motor bus, the injection valves MO F042A, MO F042B and MO F042C are signaled to open.

4. The following normally closed valves are signaled closed to ensure proper system lineup:

INSERT (for Pg. 7.3-8)

Additionally, a reactor low pressure permissive is provided in one-out-of-two twice logic before the injection valves are to signalled open. Manual initiation of the LPCS is provided, which bypasses the initiation logic except that the reactor low-pressure permissive must be present to open the injection valves. Reactor pressure is monitored by eight pressure sensors, four per division, mounted on racks in the reactor building. Division I provides the interlocks for the LPCI A loop; Division II provides the interlocks for the LPCI B and LPCI C loops.

ENCLOSURE 22

QUESTION 421.035 (7.1)

Identify where microprocessors, multiplexers, or computer systems are used in or interface with safety-related systems.

RESPONSE

~~The response to this request will be provided by September 1983~~.

REPLACE WITH INSERT

INSERT (for Pg. Q&R 7.1-13)

Microprocessors, multiplexers, or computer systems are used in, or interface with, safety-related systems as follows:

1. A microprocessor-based temperature scanner monitors a substantial number of inputs originating from RTD and thermocouple type devices which monitor various temperatures associated with Class 1E and non-Class 1E equipment. The scanner serves no direct safety function and consequently has been procured as non-Class 1E. The following safety-related equipment have RTD's and thermocouples which are used as inputs to the subject scanner:

System	Temperatures Monitored
High Pressure Core Spray	Pump Motor Stator and Bearing
Low Pressure Core Spray	Pump Motor Stator and Bearing
Residual Heat Removal	Pump Motor Stator and Bearing
Standby Liquid Control	Pump Bearing
Reactor Core Isolation Cooling	Pump and Turbine Bearing
Standby Diesel Engine	Sleeve Bearing

A thermocouple is not essential to emergency reactor shutdown, containment and reactor heat removal and therefore is not a Class 1E device. However, it does share a common enclosure (the motor case) with a Class 1E circuit (the motor windings).

In accordance with IEEE 384 paragraph 6.2.1.1, an isolation device is not required on the thermocouple circuit if the independence of redundant Class 1E circuits (the motors) can maintain protection functions required during and following any design basis event as discussed below.

The operation of a motor can be expected to be affected in the following manner:

(i) During a high voltage spike from temperature scanner. Thermocouple extension wire insulation is tested to withstand 2500 volts for 5 minutes while motor winding insulation is tested to withstand 11000 volts ac for one minute. A high spike from the scanner does not affect motor winding insulation and its operation, but can damage thermocouple winding insulation thereby disabling or damaging the temperature scanner system.

(ii) Motor winding faults to thermocouples in one motor cannot cause damage or otherwise affect the operation of another motor. Any voltage that may appear at a thermocouple of another motor due to fault, as stated above, is much less than its rated insulation strength (11,000 volts) of that motor. The existence of such a voltage and the circumstances of its production may cause damage or impair operation of an individual thermocouple sensor, its scanner or thermocouple in the circuits. However, this affects monitoring and not operation.

2. The plant computer inputs from safety related circuits are optically isolated. A description of the NSSS process computer system is provided in Section 7.7.1.6.

3. The emergency response information system (ERIS) computer is isolated from interfacing safety systems using the isolation criteria of FSAR Table 1.8-1 for Regulatory Guide 1.75. A description of ERIS is provided in Section 7.7.1.7.

4. The digital radiation monitoring system (DRMS) is isolated from interfacing safety systems using the isolation criteria of FSAR Table 1.8-1 for Regulatory Guide 1.75.A description of DRMS is provided in Section 7.7.1.8.

7.7 CONTROL SYSTEMS NOT REQUIRED FOR SAFETY

7.7.1 Description

Section 7.7 describes instrumentation and controls of major plant control systems whose functions are not essential for the safety of the plant. The systems include:

1. Rod control and information system (RC&IS)
2. Recirculation flow control system
3. Feedwater control system
4. Steam bypass and pressure regulating system
5. Refueling interlocks.
6. Process computer system 9

Insert →

Refer to Table 7.7-2 for similarity in system design to licensed reactors.

7.7.1.1 Rod Control and Information System (RC&IS)

1. RC&IS Function

The RC&IS provides the operator with the means to make changes in nuclear reactivity by manipulating control rods so that the reactor power level and power distribution can be controlled.

This system includes the interlocks that inhibit rod movement (rod block) under certain conditions. The RC&IS does not include any of the circuitry or devices used to automatically or manually scram the reactor; these devices are discussed in Section 7.2. In addition, the mechanical devices of the CRDs and the control rod hydraulic system are not included in the RC&IS. The latter mechanical components are described in Section 4.1.3.

2. RC&IS Operation

The RC&IS includes the following:

1. CRD - control system
2. Rod block interlocks
3. Rod position probes
4. Position indication electronics.

Insert (for Pg. 7.7-1)

7. Emergency Response Information System (ERIS)

8. Digital Radiation Monitoring System (DRMS)

9. Process computer interface with rod control and information system. 9

INSERT →

7.7.1.~~7~~9 Design Differences

Refer to Table 7.7-2 for a list of instrumentation and control system designs and their similarity to designs of other nuclear power plants.

7.7.2 Analysis

Refer to the safety evaluations in Chapter 15 and Appendix 15A. Chapter 15 shows that the systems described in Section 7.7 are not utilized to provide any DBA safety function. Safety functions are provided by other systems.

Chapter 15 also evaluates all credible control system failure modes, the effects of those failures on plant functions, and the response of various safety-related systems to those failures.

INSERT (for Pg. 7.7-33)

7.7.1.7 EMERGENCY RESPONSE INFORMATION SYSTEM (ERIS)

7.7.1.7.1 ERIS Function

The function of the Emergency Response Information System is to gather plant data, store and process that data, generate visual displays of plant status information, and provide printed and plotted records of transient events.

1. System Operation

   Data Acquisition System (DAS) - the data acquisition system interfaces with existing plant sensors or devices, converts the acquired signals to digital data, and performs pre-processing of the data before passing it on to the central processors. Self test features are built into each element of the DAS.

   Remote Input Modules (RIM) - Remote input modules are part of the DAS and are mounted in the control room or in local panels to receive plant signals to be used in ERIS. Modules that interface with safety related devices are qualified to the same standards such that total system integrity is maintained. The input modules provide isolation amplifiers between the incoming signals and ERIS. Additional isolation is achieved through use of fiber optic cable which can be used to connect the input modules to the data multiplexer or data formatter. Signal conditioning and digitizing are accomplished by the input modules.

   Data Multiplexer Module (MUX) - The data multiplexer is part of the DAS and receives inputs from several input modules and then multiplexes these signals to the data formatters. Multiplexing reduces the number of wires between the remote input modules and the data processors.

   Data Formatter Module (DFM) - The data formatter module is part of the DAS and performs some preprocessing of data before sending it to the data processing system.

   Data Processing System (DPS) - The data processing system receives data from the DAS, stores the data, performs calculations, validates the information by comparing redundant or secondary signals through appropriate calculations, and generates displays according to programmed formats. DPS uses two processors to accomplish these tasks, the Transient Recording and Analysis (TRA) and the Real Time Analyses and Display (RTAD) processors. The TRA processor receives ERIS data from the DAS and stores it on magnetic disks. For post-event analysis, the TRA processor retrieves stored data and performs the necessary computations for

formatting to provide outputs as requested from the graphic display console. the RTAD processor receives ERIS data from the DAS and performs necessary computations to convert data to a format suitable for real time display on the CRT's. It also performs the validation function of input signals. The RTAD processor also stores data on magnetic disk. This data can be retrieved to provide trend display information upon request. If either processor fails both functions can be accomplished by the remaining processor with minor diminished capacity.

Graphic Display Console - The graphic display console is a panel containing two cathode ray tubes (CRTs) and two keyboards. The CRTs generate a variety of graphic real-time displays that are available on command from the keyboard. The displays provide the plant operator with a central display of critical "symptoms" of the plant condition that assist the operator in entering and following procedures developed from the Emergency Procedure Guidelines (EPG) and initiating the required actions. Different displays can be shown on each CRT simultaneously.

Technical Support Center (TSC) - The technical support center consists of a CRT display console located away from the main control room with access to the outputs from ERIS.

Emergency Operations Facility (EOF) - The emergency operations facility, as part of ERIS, consists of a CRT display console located remote from the main control room with access to outputs from ERIS.

ERIS Outputs - The Emergency Response Information System is capable of the following outputs to aid the operator when dealing with emergency situations:

a. Critical Plant Variables display - A concise display of critical plant variables to provide for rapid assessment of safety status of the plant is provided for the operator. Plant parameters are displayed with a mimic showing the RPV, containment, drywell and suppression pool. The display shows pressure, level, temperature, power level, scram status, MSIV status, safety relief valve status, and isolation valve status. Limits are shown for variables adjacent to actual values.

b. Reactor Pressure Vessel Control display - Several displays are available showing detailed information on the RPV for "Narrow Range", "Wide Range", "Fuel Zone", "Shutdown Range", and "Full Range". Each of these displays shows reactor level, pressure, and power on a ten minute trend plot with appropriate display of key values for these variables. Also shown on the same display is status information of major systems such as LPCI, LPSC, HPCS, RCIC, CRD, RWCU, SLC, turbine control

and turbine bypass. Status information is also shown for diesel generator, safety relief valves, MSIVs, isolation valves and control rods (scram).

c. Containment Control display - Several displays are available showing detailed information for containment such as "Narrow", "Upset--Lo", "Upset--Mid", "Upset-Hi", and "Full" range. Each of these displays show suppression pool level and temperature, drywell pressure and temperature and containment temperature on ten minute trend plots with appropriate display of key values for these variables. Also shown on the same display is status information of major systems such as suppression pool cooling, drywell cooling, containment cooling, and standby gas treatment. Status information is also shown for diesel generator, safety relief valves, MSIVs, isolation valves and control rods (scram).

d. Plant Parameter Validation display - Displays validation information for critical plant parameters such as RPV level, pressure and temperature, reactor power, drywell pressure and temperature, containment pressure and temperature, suppression pool temerature and level. Validation is accomplished through comparison with redundant or secondary signals with appropriate calculations.

e. Trend Plot display - Trend plots for critical plant parameters are shown in a form similar to those on composite displays mentioned above, but in more detail with longer trend time.

f. Two Dimensional Plot display - The following two dimensional plots are available on demand: Suppression pool load limit, heat capacity level limit, heat capacity temperature limit, RPV saturation temperature, primary containment design pressure, pressure suppression pressure, drywell spray initiation pressure limit, maximum core uncovery time limit. These displays allow the operator to see at a glance available margins without having to perform manual calculations.

2. <u>Verification and Validation</u>

Verification and validation of ERIS is provided in GE Licensing Topical Report NEDE-30284-P.

3. <u>Isolation</u>

To sample a Class 1E signal a Class 1E Data Acquisition Unit is utilized. It is supplied with Class 1E power and the output is via fiber optic cable. Additional information on optical isolators is provided in Section 7.1.4.2.

7.7.1.7.2 Startup Testing and Transient Analysis and Recording

The Emergency Response and Information System (ERIS) provides for transient analysis and recording of startup test data. The initial use of this system is for the transient tests performed during the Startup Test Program. During commercial operation ERIS is used to aid in the following:

1. Verification of plant transient performance;

2. Documentation based on data recovery of unplanned transient events;

3. Routine surveillance test which require dynamic response support data;

4. Periodic check and adjustment of control systems for optimizing plant performance; and

5. System diagnostic and analytical tests necessary during the life of the plant to support various activities (e.g. maintenance, licensing requirments).

The following table summarizes the parameters in safety-related systems which are monitored for startup transient testing:

Parameter	Applicable System				
Valve Position	NSSS ADS	RHR SLCS	LPCS MSPLCS	HPCS CRIVCS	RCIC
Flow Rate	RCIC	HPCS	LPCS	RHR	
System Pressure	RCIC HPCS	RHR LPCS	RCS RPS	SLCS NBS	LDS FWS
Fluid Level	RPS NSSS	RCS	SLCS	RHR	FWS
Electric Power Availability	All Safety-Related Systems				
System Initiation Signal	ADS HPCS	RPS RCIC	CRIVCS	RHR	LPCS
System Temperatures	LDS RHR	NBS	RCS	SLCS	CMS

7.7.1.8 Digital Radiation Monitoring System

The Class 1E portions of the digital radiation monitoring system (DRMS) are identified in Section 7.6.1.5. The DRMS is further discussed below and in Sections 11.5.2.1 and 13.3.

a. Software

The system is designed to operate without being affected by failure of the non-Class 1E monitors or the non-Class 1E computers. Software for the monitors has been developed in INTEL's 8085 assembler code or in PLM. The software was developed in these codes to ensure the minimum possible execution time for each program and still have modular programming.

The DBM (Data Base Manager) module is the file task that controls all external accesses to the monitor's data base. Error reporting and access logging is provided in addition to the normal data base reads and writes.

DBM is responsible for controlling who has access to which item within the data and under what circumstances. DBM's control prevents a Class 1E monitors data base from being charged by a device other than its local control panel (portable) or remote 1E cabinet in the main control room.

Each monitor is equipped with three separate communication parts. All three parts are 0-30 mA current loops and operate synchronously in a half duplex mode. Two parts are for communicating to the non-Class 1E DEC 11/34 computer and operate at 4800 band via Class 1E communication isolation devices (see Item B). The third part is in for communicating to the 1E cabinets in the MCR or the local control panel (portable) at 1200 band. In order to prevent blocking of transmission on the DEC 11/34 computer loop the first two ports are equipped with hardware relay bypasses which shunt the loop transmission around the monitor in the cases of failure.

Validity checking is performed on all raw data before any further action occurs. Usually it involves checking the values of the data to insure that it is within acceptable limits of range. In some cases the validity is dependent upon the value of the data the previous time it was sampled.

b. Isolation

The communication isolation device provides physical separation and electrical isolation between Class 1E circuits and non-Class 1E circuits and between circuits of different safety classifications.

Circuits outside the isolation box are physically separated by 16 in. between input and output conduit entries.

Optically coupled isolators, each consisting of a 3-in. light pipe between an infrared light-omitting diode (LED) and a silicon photo-transistor, provide electrical isolation.

All IE equipment is fabricated to the applicable sections of IEEE 323-1974, IEEE 384-1977, IEEE 344-1975, and Regulatory Guides 1.75 (Rev. 2) and 1.89.

ENCLOSURE 23

QUESTION 421.037 (7.1)

The FSAR information provided describing the separation criteria for instrument cabinets and the main control board is insufficient. Please discuss the separation criteria as it pertains to the design criteria of IEEE Std. 384-1977, Sections 5.6 and 5.7. Detailed drawings should be used to aid in verifying compliance with the separation criteria.

RESPONSE

The response to this request ~~will be provided by September 1983~~. is provided in revised Section 7.1.2.3, Item B. Sections 5.6 and 5.7 of IEEE 384-1977 are identical to IEEE 384-1974.

The GE Licensing Topical Report NEDO-10466A is applicable to the RBS Power Generation Control Complex (PGCC) design except for the limited use of Richlite floor plates. The Richlite floor plates provide flexibility in installation while meeting floor plate requirements. The Richlite plates replace floor plates described in NEDO-10466A which cannot be modified in the field to fit special cases or close tolerance fits.

4. Conformance to IEEE 336-1971 - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

Where applicable, purchase and contract specifications define installation, inspection, and testing requirements for plant instrumentation and controls. Conformance to IEEE 336-1971 is discussed in Section 8.1.

5. Conformance to IEEE 338-1971 - Periodic Testing of Nuclear Power Generating Stations

Conformance to IEEE 338-1971 is presented on a system basis in the analysis portions of Sections 7.2, 7.3, 7.4, and 7.6 as part of the discussion of Regulatory Guide 1.22 compliance.

6. Conformance to IEEE 344-1975 - Seismic Qualification of Class 1E Equipment

All safety-related instrumentation and control equipment is classified as Seismic Category I, designed to withstand the effects of the safe shutdown earthquake (SSE) and remain functional during normal and accident conditions. Qualification and documentation procedures used for Seismic Category I equipment and systems are identified in Section 3.10.

7. Conformance to IEEE 379-1972 - Application of Single-Failure Criterion to Nuclear Power Generating Stations

The extent to which the single-failure criteria of IEEE 379-1972 are satisfied is specifically covered for each system in the analysis of IEEE 279-1971, Paragraph 4.2 in Sections 7.2, 7.3, 7.4, and 7.6.

8. Conformance to IEEE 384-1974 - Independence of Class 1E Equipment and Circuits

The safety-related systems described in Sections 7.2 through 7.6 meet the independence and separation criteria for redundant systems in accordance with IEEE 279-1971, Paragraph 4.6.

The criteria and bases for the independence of safety-related instrumentation and controls, electrical equipment, cable, cable routing, marking, and cable derating, are discussed in Section 8.3. Fire detection and protection in the areas where wiring is installed are described in Section 9.5.1, and in Appendix 9A.

INSERT

INSERT (for Pg. 7.1-8)

RBS instrument cabinets and main control room boards meet the separation criteria defined in Sections 5.6 and 5.7 of IEEE Standard 384 (1974).

The preferred method of separation at RBS is by physical separation of redundant Class 1E systems by safety class structures. Where physical separation by separate enclosures is not possible because of the plant design, a barrier or a six (6) inch minimum separation distance is provided. Instances where a barrier or six inch separation is not provided as required have been analyzed to insure compliance with R.G. 1.75, Revision 2 and IEEE Standard 384 (1974).

Control panels are physically separated such that hazards such as fire, missiles, pipe whip, and water sprays including fire protection water systems do not cause failures common to redundant Class 1E functions. Consult FSAR Sections 9.5, 3.5, and 3.6 for additional information. Further, the station arrangement drawings shown in Section 1.2 of the FSAR identify equipment locations which may be used to verify separation by physical location and safety class structures. A further description of the PGCC Design is provided in Reference 2.

References- 7.1

1. GE Licensing Topical Report. NEDO 21617-A, December 1978.

2. Clay, H.R. Power Generation Control Complex Design Criteria and Safety Evaluation, NEDO-10466-A, February 1979.