REGULATORY INFORMATION DISTRIBUTION SYSTEM (RIDS)

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FACIL:50-410 Nine Mile Point Nuclear Station, Unit 2, Niagara Moha 05000410

AUTH.NAME	AUTHOR AFFILIATION
MANGAN,C.V.	Niagara Mohawk Power Corp.

RECIP.NAME	RECIPIENT AFFILIATION
SCHWENCER,A.	Licensing Branch 2

SUBJECT: Forwards responses to SER Open Items 421.3,4,10,13,15,18,20, 23,25,27,28,34,36,37,42,43,44 & 47,to aid in NRC review of application for license.Info will be included in next FSAR amend.

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	~~RM/DDAMI/MIB~~		1	0				
EXTERNAL:	ACRS	41	6	6	BNL(AMDTS ONLY)		1	
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NIAGARA MOHAWK

NIAGARA MOHAWK POWER CORPORATION/300 ERIE BOULEVARD WEST, SYRACUSE, N.Y. 13202/TELEPHONE (315) 474-1511

September 13, 1984
(NMP2L 0152)

Mr. A. Schwencer, Chief
Licensing Branch No. 2
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Re: Nine Mile Point Unit 2
Docket No. 50-410

Dear Mr. Schwencer:

Enclosed for your use and information are the Nine Mile Point Unit 2 responses to the Nuclear Regulatory Commission's Safety Evaluation Report open items. This information has been previously discussed with your staff and is submitted to aid your review of the Unit 2 licence application for the resolution of these open items. This information includes Safety Evaluation Report open items 421.3, 421.4 421.10, 421.13, 421.15, 421.18, 421.20, 421.23, 421.25, 421.27, 421.28, 421.34, 421.36, 421.37, 421.42, 421.43, 421.44, 421.47.

The enclosed will be included in the next Final Safety Analysis Report Amendment.

Very truly yours,

CVMangan

C.V. Mangan
Vice President
Nuclear Engineering & Licensing

NRL;ja
Enclosure
xc: Project File (2)

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LIMITED DISTRIBUTION

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of	)	
Niagara Mohawk Power Corporation	)	Docket No. 50-410
(Nine Mile Point Unit 2)	)	

AFFIDAVIT

C.V. Mangan, being duly sworn, states that he is Vice President of Niagara Mohawk Power Corporation; that he is authorized on the part of said Corporation to sign and file with the Nuclear Regulatory Commission the documents attached hereto; and that all such documents are true and correct to the best of his knowledge, information and belief.

C Mangan

Subscribed and sworn to before me, a Notary Public in and the the State of Maryland and County of Montgomery, this 13 day of September 1984.

Ruth Etheridge
Notary Public in and for
Montgomery County, Maryland

My Commission expires:

7/1/86

QUESTION F421.3 (7.1, 7.2, 7.3, 7.4, 7.5, 7.6)

Identify any "first-of-a-kind" instruments used in or providing inputs to safety-related systems. Identify each application of a microprocessor, multiplexer or computer system where they are in or interface with safety-related systems.

RESPONSE

For BOP

The Unit 2 transient analysis recording system utilizes the validyne remote signal multiplexer, MC3TOAD-Q2, to provide isolation of 1E signals from non-1E equipment. The multiplexer unit and associated plug-in signal conditioning modules provide the signal conditioning, multiplexing, and A/D conversion to process and transmit up to 32 channels of input data.

D

The following components describe the multiplexer and its associated components:

1.	MC370AD-Q2	Remote multiplexer/module case
2.	AB295-Q2	Analog multiplexer board
3.	AD296-Q2	A/D converter board
4.	PS294-Q2	Multiplexer/AID power supply brand
5.	PS171-Q2	Signal/conditioning power supply
6.	PS324-Q2	Remote DC power supply
7.	CD173-Q2	High gain carrier demodulator
8.	BA332-Q2	Buffer amplifier
9.	BA332-150-Q2	Buffer amplifier
10.	DI338-24-Q2	Digital encoder plug-in module

For details of testing against EMI, short circuit failures, voltage faults and/or surges, and the summary of performance characteristics, see the Environmental Qualification document. This equipment performs no control function and is used for nonsafety plant monitoring,

The Unit 2 digital radiation monitoring system (DRMS) supplied by Kaman Instrumentation provides isolation of 1E digital, analog, and communication signals from non-1E equipment.

The following modules describe the DRMS isolators.

1. KESIM - Kaman safety radiation monitoring system isolation module provides electrical isolation between the serial data lines of the Class 1E data acquisition units and the non-1E redundant microcomputers.

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410 Nine Mile

2. KEI-D - Kaman digital isolation module provides isolation between the Class 1E and non-1E digital signals. 1.54

3. KEI-A - Kaman analog isolation module provides isolation between the Class 1E and non-1E analog signals. 1.57

For details of testing against EMI, short circuit failures, 2.1
voltage faults and/or surges, and the summary of performance 2.2
characteristics, see the Environmental Qualification 2.3
document.

STEPS HAVE BEEN TAKEN TO ASSURE THE VALIDITY OF SOFTWARE FOR THE DRMS. THE SUPPLIER OF THE DRMS HAS BEEN REQUIRED TO HAVE A VERIFICATION AND VALIDATION PROGRAM. NMPC AND SWEC HAVE JOINTLY PARTICIPATED WITH THE VENDOR TO DEVELOP AN INTEGRATED SYSTEM TEST WHEREIN ALL FUNCTIONS SPECIFIED FOR INCLUSION INTO THE DRMS SOFTWARE WILL, IN FACT, BE VERIFIED BY THE USER. THIS TEST WILL BE RUN IN THE VENDOR'S SHOP WITH ALL EQUIPMENT CONNECTED AND OPERATIONAL.

SYSTEM DESCRIPTION

THE KAMAN DIGITAL RADIATION MONITORING'S DATA ACQUISTION SYSTEM CONSISTS OF EIGHT SERIALLY CONNECTED LOOPS OF RADIATION MONITORING UNITS. SIX OF THESE MONITORING LOOPS ARE COMPRISED OF NON CLASS-1E RADIATION MONITORS. THE TWO REMAINING MONITORING LOOPS CONTAIN CLASS 1E, NUCLEAR SAFETY RELATED RADIATION MONITORS. EACH MONITORING LOOP COMMUNICATES WITH THE DIGITAL RADIATION MONITORING SYSTEM VIA AN EIA-RS-422 INTERFACE. THE CLASS 1E RADIATION MONITORS MEASURE RADIATION LEVELS IN CERTAIN PROCESSES AND AREAS CRITICAL TO PERSONNEL SAFETY. THESE CLASS 1E RADIATION MONITORS INTERFACE WITH THE DATA PROCESSING SUBSYSTEM IN SUCH A WAY AS TO ENSURE ELECTRICAL ISOLATION/SEPARATION. THIS CLASS 1E WIRING WILL MAINTAIN ELECTRICAL INTEGRITY AND IMPROVE RESPONSE TIMES TO PERSONNEL THREATENING ALARM CONDITIONS. DATA ACQUISTION FROM CLASS 1E MONITORS AND NON-CLASS 1E MONITORS IS SIMILAR. THE ONLY EXCEPTION IS THE MANIPULATIVE CONTROL OF THE CLASS 1E MONITORS. MANIPULATIVE CONTROL OF THE CLASS 1E MONITORS IS ONLY AVAILABLE FROM THE ASSOCIATED AUXILIARY CONTROL UNIT (ACU) LOCATED IN THE ALARM AND DATA DISPLAY SUBSYSTEM (ADD: L2CEC#PNL85). THE NON-CLASS 1E MONITORS' MANIPULATIVE CONTROL IS AVAILABLE FROM THE DATA PROCESSING SUBSYSTEM (DPS), AS WELL AS LOCALLY.

THE DATA PROCESSING SUBSYSTEM (DPS) MAY COMMUNICATE WITH A CLASS 1E DATA AQUISITION UNIT (DAU) TO RETRIEVE ALL ACCUMULATED DATA. HOWEVER, THE DATA PROCESSING SUBSYSTEM (DPS) OPERATOR CANNOT ALTER ANY INFORMATION ACQUIRED BY THE CLASS 1E DATA ACQUISTION UNIT (DAU) OR COMMAND ANY MONITOR FUNCTIONS. SOFTWARE CHECKS IN BOTH THE DATA PROCESSING SUBSYSTEM (DPS) AND THE DATA ACQUISITION UNIT (DAU) ASSURE THAT THE ABOVE CONDITIONS ARE MET. IN ORDER TO INSURE THAT THE DATA PROCESSING SUBSYSTEM (DPS) OPERATOR HAS THE CURRENT STATUS OF THE CLASS 1E MONITORS FOR DISPLAY AND LOGGING, THE CLASS 1E DATA ACQUISITION UNIT (DAU) WILL NOTIFY THE DATA PROCESSING SUBSYSTEM (DPS) OF ANY DATABASE CHANGES MADE BY AN AUXILIARY CONTROL UNIT (ACU) OPERATOR. THIS UPDATE OF THE DATA PROCESSING SUBSYSTEM'S (DPS'S) DATABASE WILL BE ACCOMPLISHED BY MEANS OF AN "UPLOAD" MESSAGE FROM THE DATA ACQUISITION UNIT (DAU). THE CLASS 1E DATA ACQUISITION UNITS (DAU) UTILIZES A DEDICATED SERIAL CHANNEL TO COMMUNICATE WITH ITS ASSOCIATED AUXILIARY CONTROL UNIT (ACU). THE SAFETY RADIATION MONITORING SYSTEM (SRMS) MODULES PROVIDES THE CLASS 1E TO NON-CLASS 1E ISOLATION TO THE DATA PROCESSING SUBSYSTEM (DPS). ANALOG AND DIGITAL ISOLATORS ARE ALSO PROVIDED TO SEPARATE THE AUXILIARY CONTROL UNIT (ACU) OUTPUTS FROM THE NON-CLASS 1E INTERFACES. THE ALARM AND DISPLAY SUBSYSTEM (ADDS) CONTAIN CLASS 1E RECORDERS WHICH MONITOR:

AND DOCUMENTS RADIATION LEVELS.

NOTED AUG 1-6 1984 H. PINKSTON-JR.

Digital Radiation Monitoring System

1. ACRONYMS

a. DPS - Data Processing Subsystem (redundant minicomputers located in computer room) - non 1E

b DAU - Data Acquisition Unit - (microcomputers located local to process/area) - 1E and non 1E applications

c ADDS - Alarm and Display Subsystem (Class 1E control room cabinets - 2CEC* PNL 880 A → D)

d ACU - Auxiliary Control Unit - (located in ADDS - 1 for each monitor) - Class 1E

e SRMS - Safety Radiation monitoring system - module located in ADDS provides parallel communications to 1E DAU associated with 1E monitors.

f SIM - Safety Isolation module - located in ADDS for isolating the communications channel from the SRMS to the DPS while maintaining required separation & Isolation of 1E/non 1E devic

G PAM - Post Accident Monitor

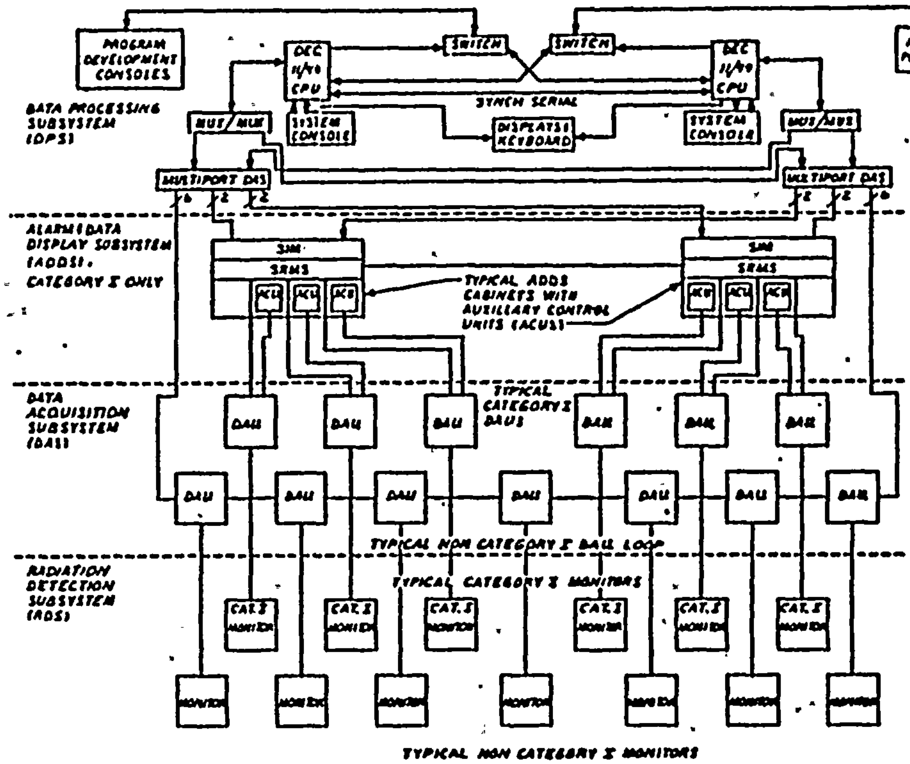

FIGURE 2-1

SYSTEM CONFIGURATION FOR NMP

D 77028 FIGURE 2-1

GE130

QUESTION

421.3 Identify any "first-of-a-kind" instruments used in or providing inputs to safety-related systems. Identify each application of a mircroprocessor, multiplexer or computer system where they are in or interface with safety-related systems.

(7.1)
(7.2)
(7.3)
(7.4)
(7.5)
(7.6)

RESONSE

For NSSS

1) There are no "first-of-a-kind" instruments ued in or providing inputs to safety-related systems.

2) Microprocessors are used as an integral part of the Redundant Reactivity Control System (RRCS). Four microprocessors (2/division) receive input signals, (e.g. low water level, high dome pressure, APRM downscale), process them against a time base formula, and generate output signals (e.g. ARI, recirc pump trip, feedwater runback) to other systems. Details of RRCS operation are discussed in Section (7.6.1.X). In addition to these data processing microprocessors, the RRCS has 4 microprocessors (2/division) for monitoring power supply status, 2 microprocessors (1/division) for assisting in the calibration of RRCS process instrumentation, and 2 microprocessors (1/division) to perform automatic on-line testing of the safety related RRCS system. Hardware failures are annunciated and faults localized via use of a local keyboard/display.

The performance monitoring system (PMS), which interfaces with safety-related systems, is a non-safety-related system. Isolation of safety-related inputs to the PMS is shown functionally in the logic diagrams and elementary diagrams listed in Table 1.7-1 and provided to the NRC.

QUESTION F421.4 (7.1, 7.2, 7.3, 7.4, 7.5, 7.6)

Section 7.1.2.3 of the FSAR provides a brief discussion on conformance to Reg. Guide 1.47. Discuss in detail the design of the bypassed and inoperable status indication using detailed schematics. Include the following information in the discussion:

1. Compliance with the recommendations of Reg. Guide 1.47 and Reg. Guide 1.22 Position D.3a and 3b.

2. The design philosophy used in the selection of equipment/systems to be monitored, including auxiliary and support systems.

3. How the design of the bypass and inoperable status indication systems comply with Positions B1 through B6 of ICSB Branch Technical Position 21.

4. The list of system automatic and manual bypasses as it pertains to the recommendations of Reg. Guide 1.47.

5. Discuss hardware features employed to provide a consolidated, human factored, display of the bypassed and inoperable status of ESF equipment.

RESPONSE

1. Refer to ~~Chapter 1~~ Section 1.8 for degrees of compliance with Regulatory Guides.

2. Automatic bypassed and inoperable status indication is provided for all systems that affect plant safety. This indication system accompanies any operational procedure for all safety-related systems.

   Any deliberate action which makes a support system inoperable and also inhibits the proper function of a dependant safety system will also be automatically indicated.

   Equipment within the supporting/safety-related systems that is Class 1E is annunciated (component level). In this group, the equipment that when bypassed causes a system to be defeated, will contribute to its respective system level annunciator and indicate a bypassed system condition. If a system is declared inoperable, whether it be a redundant portion of a system or a total system, and also supports other systems, the bypassed and inoperable indication will cascade into the dependent systems

3\. ALL OF THE SYSTEMS LISTED UNDER ~~[illegible]~~ PART 1 4 WILL HAVE ~~[illegible]~~ certain BYPASSED AND INOPERABLE STATUS INDICATION SYSTEM EMPLOYED. EITHER THE TOTAL SYSTEM/CASCADED SYSTEM APPROACH OR JUST COMPONENT INDICATION WILL BE PROVIDED. ~~REFERENCE THESE SIGNALS FOR THE LOGIC EMPLOYED IN THE SAFETY AND SUPPORT SYSTEM INOPERABILITY LOGIC.~~

THE DESIGN OF THE BYPASSED AND INOPERABLE STATUS INDICATION SYSTEM ~~[illegible]~~ COMPLIES WITH BRANCH TECHNICAL POSITION ICSB-21 AS discussed below: ~~[illegible]~~ ~~AS FOLLOWS.~~

A. THE COMPONENT LEVEL BYPASS INDICATORS ARE ARRANGED WITHIN THEIR RESPECTIVE SYSTEM CONFINES ON THE CONTROL PANELS. THE SYSTEM LEVEL ANNUNCIATOR IS LOCATED IMMEDIATELY ABOVE THE COMPONENT LEVEL INDICATOR MATRIX WITHIN THE STANDARD PLANT ANNUNCIATOR SYSTEM. ALL INOPERABILITY ANNUNCIATION IS AMBER IN COLOR.

B. THE DESIGN OF THE BYPASSED AND INOPERABLE STATUS INDICATION SYSTEM WILL INDICATE WHICH PARTICULAR SYSTEM AND/OR SYSTEMS ARE AFFECTED WHENEVER A COMPONENT OR FUNCTION IS RENDERED INOPERABLE. THIS IS PROVIDED BY THE INTEGRATED SYSTEM/CASCADED SYSTEM APPROACH.

C. THE OPERATOR AT NO TIME CAN CANCEL AN AUTOMATIC BYPASS CONDITION THAT HAS BEEN ANNUNCIATED. ONLY THE MANUAL INOPERABILITY FUNCTION WHICH IS PROVIDED FOR EQUIPMENT AND/OR FUNCTIONS THAT DO NOT HAVE AN AUTOMATIC INDICATION FEATURE, and CAN BE EITHER ACTIVATED OR DE-ACTUATED.

D. THE DESIGN INTENT OF THE BYPASSED AND INOPERABLE STATUS INDICATION SYSTEM IS TO AID THE OPERATOR IN DETERMINING THE OPERABILITY OF A PARTICULAR SYSTEM. THIS INDICATION SYSTEM DOES NOT PERFORM ANY ~~[illegible]~~ FUNCTIONS THAT MAY IMPEDE A PROTECTIVE SYSTEMS' PERFORMANCE.

E. ALL OF THE EQUIPMENT USED IN THE BYPASSED AND INOPERABLE STATUS INDICATION SYSTEM IS QA CATEGORY I. ~~WHICH IS EQUAL WITH ALL OF THE [illegible] SYSTEMS [illegible],~~ THEIR BEING ~~QA CATEGORY I~~ ALSO. ~~[illegible]~~ NO ADVERSE EFFECT ON THE INTERDEPENDENCE BETWEEN SAFETY SYSTEMS EXISTS.

F. THE BYPASSED AND INOPERABLE STATUS INDICATION SYSTEM HAS PUSH-TO-TEST INDICATORS FOR COMPONENT LEVELS AND THE MANUALLY INOPERABLE FEATURE FOR SYSTEM LEVEL ANNUNCIATOR ILLUMINATION.

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4. The following list of systems are provided with bypass inoperable status. 2.27
2.28

System Mnemonic	Systems Containing Bypassed/Inoperable Requirements	
		2.35 a 2.36
ADS	Automatic Depressurization System RS 24 VDC SYSTEM ~~[illegible]~~	2.38 a 2.39 a
BYS	Battery System	? 41
CCP	Reactor Building Closed Loop Cooling Water (Component Level Only)	2.52 2.53
CMS	Containment Atmosphere Monitoring	2.55
CPS	Primary Containment Purge (Component Level Only)	2.57 2.58
CSH	High Pressure Core Spray - Power Supply	3.2
CSL	Low Pressure Core Spray	3.4
DER	Reactor Building Equipment Drains (Component Level Only)	3.6 3.7
EGA	Standby Diesel Generator Air Startup	3.9
EGF	Standby Diesel Generator Fuel	3.11
EGP	Standby Diesel Generator Protection (Breaker)	3.13
EGS	Standby Diesel Generator Protection (Generator)	3.15 3.16
EJS	Standby Station Service Substation	3.18
ENS	Standby Station Service Supply Breakers	3.20

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System Mnemonic	Systems Containing Bypassed/Inoperable Requirements	
FPW	Fire Protection - Water (Component Level Only)	3.22
FWS	Feedwater System (Component Level Only)	3.24
GTS	Standby Gas Treatment	3.26
HCS	Hydrogen Recombiner	3.28
HVC	Control Building Air Conditioning	3.30
HVK	Control Building Chilled Water	3.32
HVP	Standby Diesel Generator Building Ventilation	3.34
HVR	Reactor Building Ventilation (Component Level Only)	3.36
HVY	Yard Structure Ventilation (Component Level only)	3.38
IAS	Instrument Air (Component Level Only)	3.40
MSS	Main Steam (Component Level Only)	3.42
RHS	Residual Heat Removal	3.44
SFC	Spent Fuel Pool Cooling and ~~Purification~~ Clean up	3.46
SWP	Service Water	3.48
WCS	Reactor Water Cleanup (Component Level Only)	3.50

5. It is not a requirement of Regulatory Guide 1.47 that 3.57
the bypassed and inoperable status indication system be 3.58
Class 1E. However, the control circuit wiring is 4.1
associated with the Class 1E components and is designed 4.2
in accordance with Class 1E requirements. Optical 4.3
isolation will be employed to separate the annunciator,
which is a non-Class 1E circuit, from the bypassed and 4.4
inoperable logic circuits.

The component level inoperability will be displayed 4.6
using master specialty switch-light units within their 4.7
respective operating area on the control panel.

The system level indicators used are the standard plant 4.8
annunciator windows separated into divisions if 4.9
applicable. At the system level, the indicators will be 4.10
accompanied by an audible alarm. All bypassed and 4.11

inoperable status indication has unique amber illumination.

QUESTION F421.10 (7.1)

Section 1.10 of the FSAR provides a response to NUREG-0737. The discussion on item II.D.3 does not mention alarms associated with the valve position indication. Confirm that alarms are provided in conjunction with the position monitoring system. The discussions on items II.K.3.13, II.K.3.21 and II.K.3.22 briefly address modifications that will be made to the RCIC and HPCS systems. Provide a detailed discussion on the design modifications proposed for these systems. Use one-line diagrams and other drawings as appropriate.

RESPONSE

See revised Section 1.10 for Item II.D.3.

TMI Item II.K.3.13 resulted in the modification of the RCIC system to allow automatic restart after RCIC system shutdown due to high water level (Level 8) signal. Instead of tripping the RCIC turbine which required operator action to allow restart of the system, RCIC steam supply valve E51-F045 is closed, shutting down RCIC turbine/pump operation. Four separate transmitter/trip units energize individual relays, arranged in a one-out-of-two-twice logic configuration, to provide the closure signal for the valve F045. If the water level falls to Level 2, the system initiation logic will reopen the steam supply valve, restarting RCIC operation.

See revised Section 1.10 for Item II.K.3.21.

TMI Item II.K.3.22 resulted in the modification of the RCIC system to allow automatic switchover of pump suction from the condensate storage tank to the suppression pool if the condensate storage tank falls to a preset low level. Low level in the tank is monitored by two redundant level transmitters. If either transmitter senses low level, pump suction is automatically transferred to the suppression pool. These are different transmitters/trip units from those that activate switchover for the HPCS system. The condensate storage tank suction valve will be signaled to close upon opening of the suppression pool suction valve. The RCIC elementary (Drawing No. 807E173TY, Rev. 14) shows the circuitry details.

The P&ID and elementary diagram will be revised to reflect a relocation of the transmitter to the pump suction line.

See Insert attached

INSERT "A" to Q421.10

Additional NRC ORAL QUESTION ON THE RCIC INITIATION LOGIC

QUESTION

The NRC questioned ~~This is in response to the question regarding~~ the length of time the operator will be required to hold the RCIC initiation button in a depressed condition to assure injection into the reactor. The concern is that if the manual initiation button is depressed only momentarily the opening of the RCIC injection valve will not be sealed in and reactor injection will not occur. The NRC has recently indicated that they feel this design may not satisfy IEEE-279, Paragraph 4.16, which requires the system, once initiated, to go to completion. ← staff

Response

The logic for the RCIC injection valve E51-F013 is shown in Attachment 1. Contacts of relays K3, K20, and K40 must all be closed for F013 to open in response to a manual initiation signal or a low reactor water level 2 signal. Relay K3 is a momentary contact relay which is energized when the manual initiation button is depressed or when reactor water level is below Level 2. Relay K20 is energized when the turbine trip and throttle valve is partially or fully open. Since the trip and throttle valve is open during system standby the contacts of relay K20 will already be closed when RCIC is started. Relay K40 is energized when the steam admission valve E51-F045 is fully closed. Since F045 is closed when the system is on standby the contacts of K40 are open at that time.

Given this logic, to manually initiate RCIC and assure the injection valve opening is sealed in, the operator must maintain the initiation switch in a depressed condition until valve F045 comes off its seat causing closure of relay K40 contacts. A red-valve position indicating light will inform the operator when F045 has started to open. At this time the initiation switch can be released since the seal-in circuit in the MCC for valve F013 will now drive it to the full open position.

OPERATED DIRECTLY FROM THE VALVE LIMIT SWITCH CONTACTS (LS6)

Limit switch LS6 energizes relay K40 when valve F045 is fully closed. Depending on the adjustment of this limit switch, it is not expected to take more than 1-2 seconds for relay K40 to be deenergized and its contacts closed when F045 starts to open. This is the time required for the operator to hold the initiation button down to assure vessel injection.

As explained in the above the contacts of relay K3 in the initiation logic have to be closed only 1 to 2 seconds before the injection valve opening logic is sealed in for automatic initiation. For an actual transient event requiring the RCIC system (i.e., loss of feedwater events) reactor water level will be below the initiation level for well over this time required to seal-in the injection valve logic, since water level will not begin to recover until the RCIC and/or HPCS is initiated. It is GE's position that this meets the intent of IEEE-279 in that the RCIC system initiation will go to completion when required for it to perform its safety function. A momentary Level 2 lasting less that 1 to 2 seconds is considered very unlikely and could only occur if feedwater flow is reestablished in time to reverse the water level drop. In this case it would be preferable not to initiate RCIC, thereby avoiding injection of cold water into the reactor.

In conclusion, GE considers the current RCIC design to be adequate and that it satisfies IEEE-279, Paragraph 4.16. Requiring the operator to hold the button for 1 to 2 seconds for a manual start does not impose a hardship on the operator. Normally, on a manual start the operator will stay with RCIC for at least 30 seconds or more to verify turbine speed, flow and valve positions. Operating procedures will include a precaution statement for the operator to ensure that he holds the manual initiation switch/button for RCIC until the valve position indicator shows the valve is opening.

Attachment I
1 of 4

QUESTION F421.13 (7.1, 7.2, 7.3, 7.4, 7.5, 7.6)

Various instrumentation and control system circuits in the plant rely on certain devices to provide electrical isolation capability in order to maintain the independence between redundant safety-related circuits and between safety-related circuits and nonsafety-related circuits. Provide the following information:

(1) Identify the types of isolation devices which are used as boundaries to isolate nonsafety-related circuits from the safety-related circuits or to isolate redundant safety-related circuits.

(2) Provide a summary of the performance characteristics from the purchase specifications for each isolation device identified in response to part (1) above.

(3) Describe the type of testing that was conducted on the isolation devices to ensure adequate protection against the effects of electromagnetic interference, short-circuit failures (line to line to ground), voltage faults, and/or surges.

RESPONSE

For BOP

1) The following list identifies the types of isolation devices that are used to isolate nonsafety-related circuits from the safety-related circuits or to isolate redundant safety-related circuits.

1. GE optical isolators

2. Potter and Brumfield MDR relays

3. Valedyne multiplexers (MC370AD-QZ)

4. Kaman Industries isolation devices

a. KESIMS (serial data line communication isolator)

b. KEI-D (digital isolation module)

c. KEI-A (analog isolation module)

INSERT

Insert

Each type of device used to accomplish electrical isolation is tested to demonstrate isolation capability under maximum credible fault conditions. These tests verify that the maximum voltage/current to which the device could be exposed within the panel/cabinet will not jeapordize the integrity of the class 1E circuits. In addition, it will be shown that any destructive effects caused by application of the worst creditable fault will not jeapordize the function of any redundent divisional circuits or devices in physical proximity to the failed device. All isolation devices comply with environmental qualifications (10CFR50.49) and seismic qualifications requirements which are the bases for plant licensing.

QUESTION

421.13 (7.1) (7.2) (7.3) (7.4) (7.5) (7.6)

Various instrumentation and control system circuits in the plant rely on certain devices to provide electrical isolation capability in order to maintain the independence between redundant safety-related circuits and between safety-related circuits and nonsafety-related circuits. Provide the following information:

(1) Identify the types of isolation devices which are used as boundaries to isolate nonsafety-related circuits from the safety-related circuits or to isolate redundant safety-related circuits.

(2) Provide a summary of the performance characteristics from the purchase specifications for each isolation device identified in response to part (1) above.

(3) Describe the type of testing that was conducted on the isolation devices to ensure adequate protection against the effect of electromagnetic interference, short-circuit failures (line to line to ground), voltage faults, and/or surges.

NSSS RESPONSE

The isolation devices used to electrically separate nonessential and essential circuits are designed to the guidelines of IEEE 384. Both relay and optical isolation devices are employed.

The optical isolators use a fiber-optic light pipe to electrically separate the input from the output. For example, an essential logic signal activates a light emitting diode; the light is transmitted through the light pipe to a photo switch; and the switch changes state upon receipt of the light signal and either blocks or transmits. These are the same types of optical isolators used in other GE plants.

The relay isolation devices provide a functionally equivalent degree of separation and are used typically for control voltage separation applications, i.e., 120-Vac and 125-Vdc essential to nonessential and redundant essential circuits. The relays are designed and mounted so that a metal barrier separates the coil from the contacts with a minimum distance of one inch between the coil and barrier and between the contact and barrier.

The designs of isolation devices are responsive to the concerns regarding susceptibility to noise, shorts, surges, and faults. Adverse conditions affecting the coil or the semiconductor device cannot propagate through the isolation barrier (i.e., metal enclosure or fiber-optic light pipe). Conversely, adverse conditions affecting the contacts or receiving semiconductor cannot propagate through the isolating barrier and affect the coil or transmitting semiconductor. Therefore, essential systems or circuits are electrically isolated from nonessential and/or redundant systems or circuits.

Summary of Purchase Specification:

A. MDR RELAY

1. Design Specification

a. MIL-R-19523
b. Contract Specification
c. Coil Specification
d. Insulation Specification
e. Design Life
f. Reliability

2. Class 1E Safety Function

a. Functional Specification
b. Reliability

3. Qualification Testing

a. Ambient and Design Environments
b. Normal Mounting

B. ISOLATOR

1. Application Data Specification
2. Performance Specification
3. Qualification Testing

a. Tested as a part of panel subassembly

The documents listed above are available for review at the General Electric offices in San Jose, CA.

The optical isolator comprises semiconductors, resistors, and capacitors mounted on a printed circuit board. As designed, this device satisfies electrical isolation requirements.

The NMP-2 NSSS uses two generations of optical isolators to provide isolation/separation between two divisional or divisional and nondivisional circuits. The PGCC uses one generation of isolator cards, and the Redundant Reactivity Control System uses a later generation. The basic difference is that the later generation has current-limiting resistors on its input circuits to more fully protect the card from damage due to excessive input signals. Installation in the panels is the same for both generations. Each is mounted in panel racks designed to hold the input and output cards separated by a 1" quartz rod through a ceramic barrier.

Specifications control the type of testing and qualification required on the isolators. The basic difference is that line to line voltage tests (140 VDC for two minutes and 400 V pulse for one msec.) were performed on the new generation isolators. Instead of this test, an input circuit 5KV line-to-ground

test was performed on the older generation isolators. In either case, subsequent to the test, it was confirmed that there was no degradation of the card on the other side of the barrier.

Additionally, the RRCS used isolated lamp drivers (card mounted relays) to isolate class 1E signals from certain non-class 1E loads (e.g., indicators). As part of its qualification, a 200 VDC line-to-line test across output contacts was performed to determine no degradation will be propagated back to the input circuit on the card.

Since the same kind of panel enclosures is used for both generations of isolators, running the 5KV test on the old generation will be sufficient to confirm the barrier (dielectric) capability for both generations of isolator cards and their housing. In addition, since the 5KV test greatly exceeds the voltage to be applied during the line-to-line test of the new generation cards, it can be considered equivalent to the test on the new generation cards, with respect to causing detriment to the cards on the other side of the barrier.

The isolator enclosures are designed to hold either four or eight isolator cards; only cards representing circuits from the same division are contained in the same enclosure. A worse case failure would only cause loss of function to one division; because of built-in redundancies in other divisions, safety functions would not be lost.

Copies of test plans, procedures, and results are on file at GE.

A summary of the qualification test performed on the MDR relay and the optical isolators are given in Attachments 1 and 2.

An additional test of the optical isolators to verify that they can withstand the maximum credible voltage applied in the transverse mode is being scheduled. This test will verify that the maximum credible voltage applied to the optical isolators in the transverse mode will not be propagated through the quartz barrier to the other side of the device.

COMMENT TO SWEC/NMPC

SWEC should provide the portion of the response concerning BOP devices used in electrical isolation. This response should be incorporated into SWEC/NMPC FSAR revision.

ATTACHMENT 1 TO QUESTION 421.13
SUMMARY OF QUALIFICATION TEST
PERFORMED ON MDR AUXILIARY RELAY

I. GENERAL

Relay Manufacturer: Potter and Brumfield
Relay Model: MDR-4130-1
GE Drawing: 169C9481
GE Design Record File: A00-901-1

II. FUNCTIONAL TEST

The following tests were performed in the sequence listed.

a. Normal Operation:

Application of normal coil rating voltage to coil terminals and observance of relay contact status change. Repeat test with gradually removing applied voltage.

b. Contact Current Rating Test:

Application of contact rated load and observance of contact status change while relay coil energization and deenergization.

c. Dropout and Pickup Voltage Test:

Gradual decrease and increase of relay coil voltage application, observance of contact status change.

d. Response Time Test:

Energization and deenergization of relay coil and recording of cycle time.

e. Dielectric Strength Test:

Application of appropriate voltage based on Mil Spec R-19523A (1230V for 120 VAC nominal, 2375V for 125 VDC nominal, 1265V for 24 VDC nominal) for one minute between relay coil circuit and relay main frame.

Acceptance Criteria - Relay shall not short out between coil circuit and contacts or frame during one minute exposure to applied voltage.

f. Typical Test Set-Up (see Figure 421.13-1)

III. SEISMIC TEST

Clutter and contact bounce monitoring in the energized and deenergized state at different times during seismic excitation.

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Relay State	NC Contact	NO Contact
De-energized @ 6.7g	5 msec. max.	No transfer of contact
Energized @ 17g	No transfer of contact	2 msec. max.

IV. ENVIRONMENTAL TEST

Exposure to temperature and humidity environment of each extreme and various conditions in between and demonstration of relay operation before, during, and after such exposure.

Environmental Exposure

a. 71°F, 60% RH
b. 55°F, 40% RH
c. 41°F, 20% RH
d. 61°F, 35% RH
e. 81°F, 50% RH
f. 101°F, 65% RH
g. 102°F, 80% RH
h. 119°F, 90% RH

V. CONCLUSION

Test samples successfully demonstrated that the relay will function before, during, and after the test exposure environment. The relay met all functional requirements as specified.

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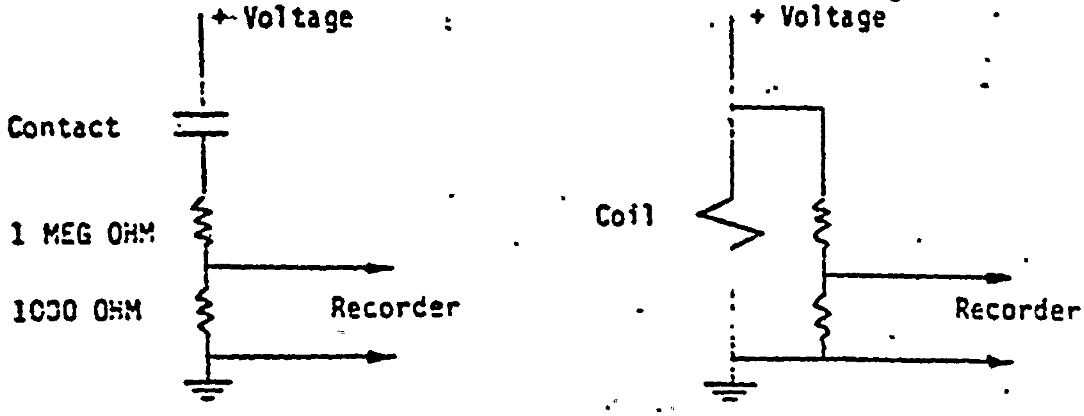
TYPICAL RECORDER CONNECTIONS



TYPICAL TEST SET-UP

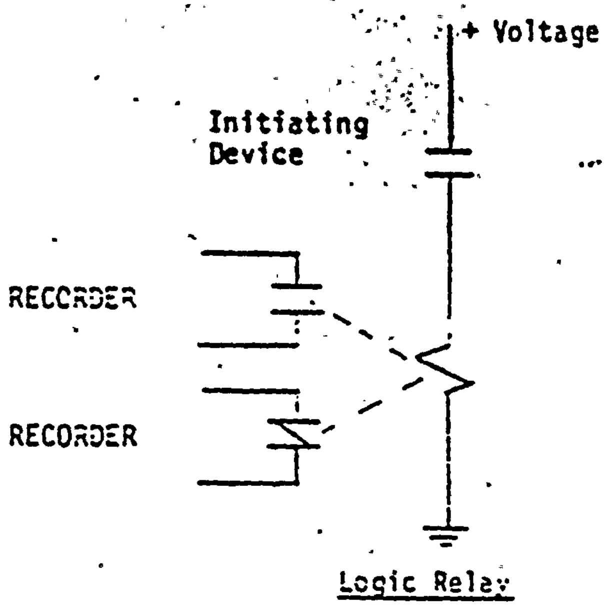


FIGURE 4.21.13-1

ATTACHMENT 2 TO QUESTION 421.13

SUMMARY OF QUALIFICATION TEST
PERFORMED ON OPTICAL ISOLATORS

I. DEVICE

Field Contact	204B6186AAG004
5V Logic Input	204B6190AAG003
12V Logic Input	204B6190AAG004
5V Logic Input	204B6190AAG005
High Speed Input	204B6198AAG002
Analog Input	204B6208AAG002
Analog Input	204B6208AAG003
Floating Low Level Output	198B6241AAG003
High Level Output	204B6188AAG002
5V Logic Output	204B6194AAG002
High Speed Output	204B6196AAG002
Analog Output	204B6220AAG002
Isolator Power Supply	198B6203AAG004
Optical Isolator	133D9947G003
Optical Isolator	133D9947G004

II. FUNCTIONAL TEST

The optical isolators were tested to verify that they met the requirements as specified in 272A8638, Isolator Application Data Information Document.

III. SEISMIC TEST

The optical isolators were tested using 22A4320 Seismic Qualification Procedure for Class 1E Electrical Equipment Test Specification.

IV. ENVIRONMENTAL EXPOSURE

TEMPERATURE (F)	RELATIVE HUMIDITY (RH)	DURATION
137	80%	100 hrs
153	80%	8 hrs
70±15 (Ambient)	50±15% (Ambient)	12 hrs
40	80%	100 hrs

V. HIGH VOLTAGE TEST

A 5KV hi-pot test was performed on the Isolators to assure that electrical isolation between the input or output will not impair the function of devices on the other side of the barrier.

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VI. DETERMINATION OF TEST VOLTAGE

A generic review of the voltage sources present within the plants utilizing optical isolators indicated that 4160 volts is the maximum voltage that could conceivably be present. Therefore, a test voltage source of 5000 volts was chosen.

The actual voltages that could be present in a panel are determined by a specific plant analysis.

VII. CONCLUSION

Test samples successfully demonstrated that the optical isolators will function before, during and after the test exposure environment and meet the qualification requirements of IEEE 323-1971 and IEEE 344-1975. It was also demonstrated that electrical isolation is maintained between input and output.

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TYPICAL TEST CONFIGURATION FOR OPTICAL ISOLATORS

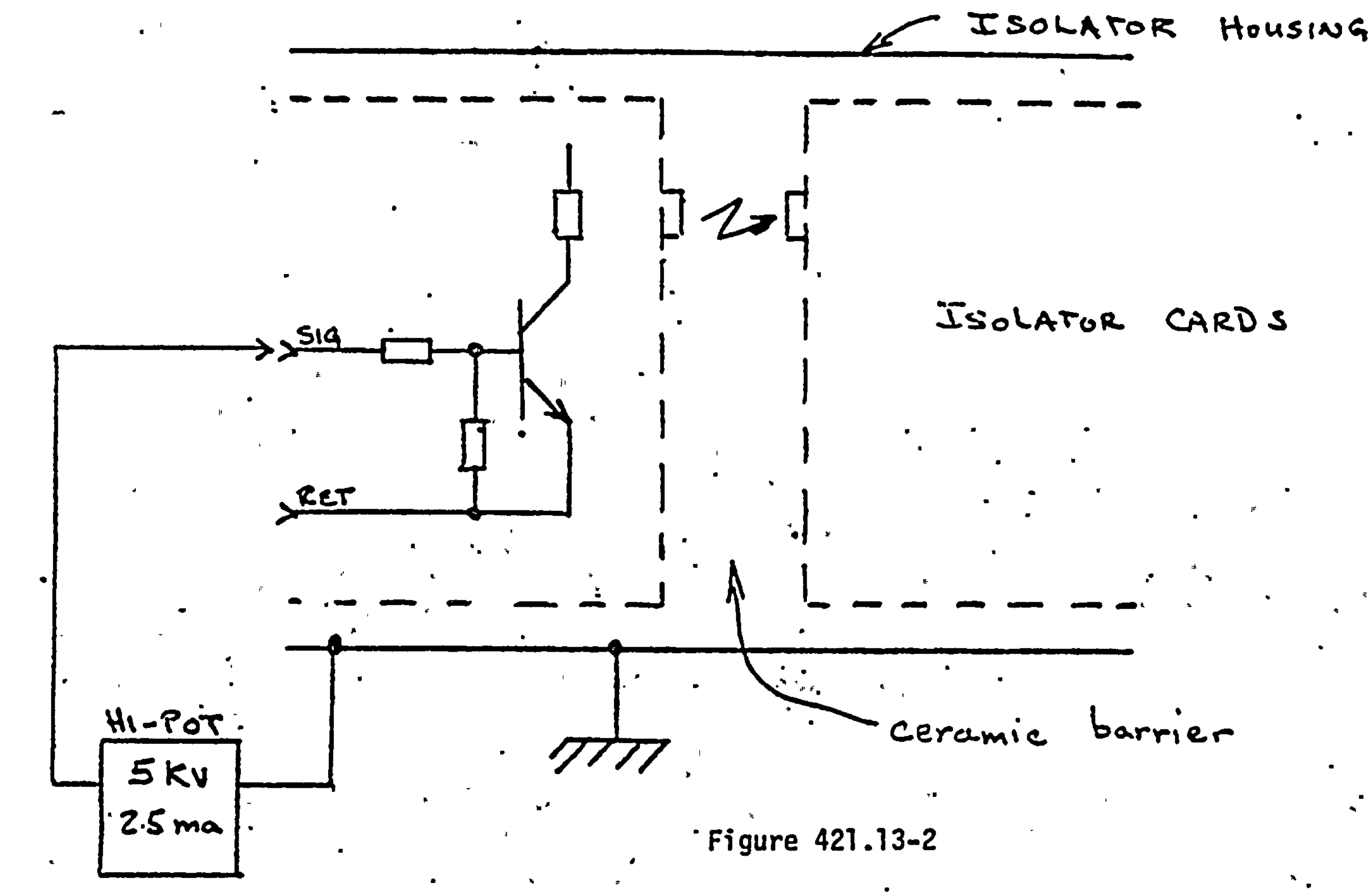

Figure 421.13-2

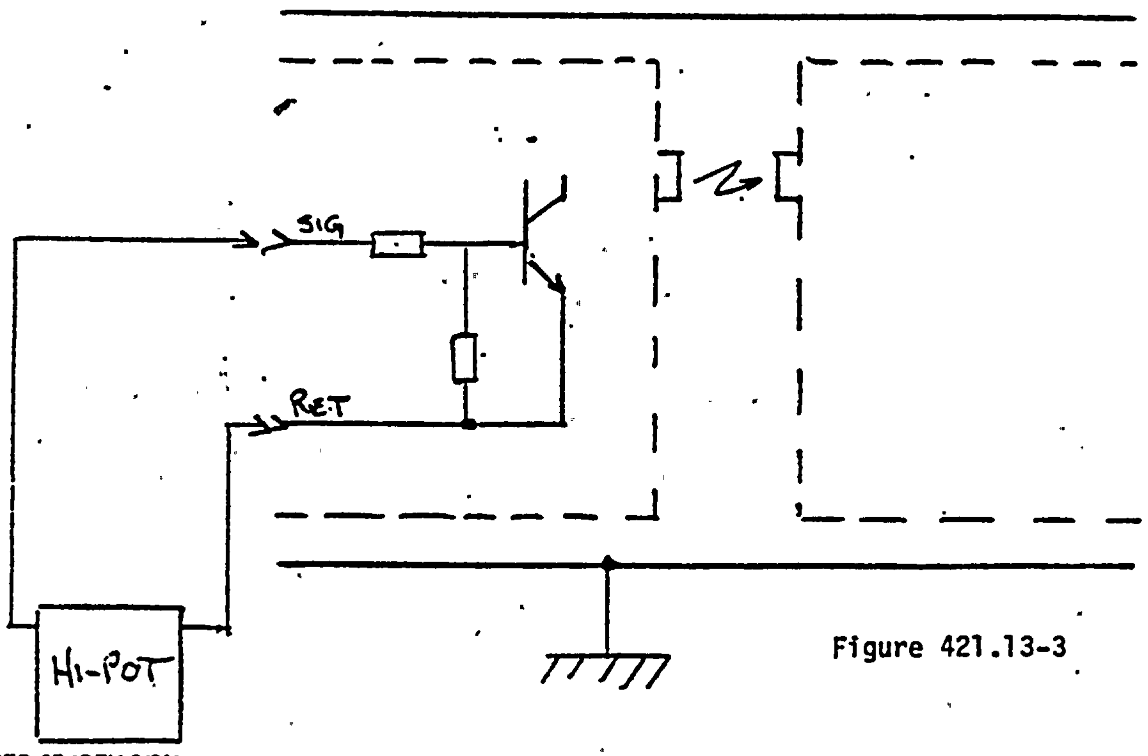

Figure 421.13-3

QUESTION F421.15 (7.1, 7.3, 7.7)

Table 7.1-2 of the FSAR provides a listing of the safety related systems similarity to licensed reactors. Eleven systems are shown to have no similarity. For these systems sufficient design details have not been provided to enable the NRC staff to verify conformance to the acceptance criteria of the Standard Review Plan (NUREG-0800). For each of these systems provide a detailed comparison of the design to the applicable requirements and recommendations delineated in Table 7-1 of NUREG-0800. Specifically identify and justify deviations from these provisions.

RESPONSE

See Section 7.1, Table 7.1-3 for applicability of standards; Section 1.8, Table 1.8-1 for Degree of Compliance to Regulatory Guides; and Section 7.1.1.2 for applicable FSAR section ~~for~~ containing the system description.

Table 421.15-1 ~~gives~~ lists examples of the Regulatory Guides and the systems they apply to

TABLE 421.15-1

REG. GUIDE	DESCRIPTION	SWEC SYSTEM (TYPICAL EXAMPLE)	FSAR SEC. NO.	FSAR FIGURE NO. (P&ID)	FSAR FIG. NO. (LSK)	FSAR DWG FROM
1.21	LIQUID RADIOACTIVE RELEASE GASEOUS RADIOACTIVE RELEAS SOLID RADIOACTIVE RELEASE	LWS, SWP RMS, OFG. WSS	11.2.3 11.3.3 11.4.4	11.2-1 A-G 11.3-1 A-C, 11.3-2 11.4-1 A-G	N/A	VOL. 11 VOL. 11 VOL. 11
1.23	ON SITE METEOROLOGICAL PROGRAM	MMS	2.3.3	2.3-1 – 2.3-46	N/A	N/A
1.45	REACTOR COOLANT PRESSUR BOUNDARY	LDS, LMS (GE-E31)	5.2	5.2-1 – 5.2-9	N/A	N/A
1.47	BYPASSED / INOPERABLE STATUS	SFC	7.1.2.3	TABLE 7.1-1 TABLE 7.1-2 TABLE 7.1-3	N/A	N/A
1.53	SINGLE FAILURE CRITERIA FOR PROTECTION SYSTEM	SFC	7.6.2.7.3	N/A	N/A	N/A
1.62	MANUAL INITIATION OF PROTECTIVE ACTIONS	CMS	7.5.2	TABLE 7.5-1	N/A	N/A
1.75	PHYSICAL INDEPENDENCE OF ELECTRICAL SYSTEMS	ISC	7.1.2.3 8.3	TABLE 7.1-3	N/A	N/A
1.89	QUALIFICATION OF 1E SYSTEMS	SWEC 1E SPECS	3.10 3.11	TABLE 3.10A-1 TABLE 3.10B-1	N/A	N/A
1.97	POST-ACCIDENT PARAMETER SET	ERF	1.8 1.10	TABLE 1.8-1, 1.8-2 TABLE 1.10-1	II.8.3-1	N/A
1.105	INSTRUMENT SETPOINTS	ALL	7.1.2.3	N/A	N/A	N/A
1.106	THERMAL OVERLOAD PROTECTION OF MOTORS	E: RHS N1E: LWS	8.3.1.1.6 8.3.1.1.5	N/A	N/A	N/A
1.120	FIRE PROTECTION GUIDELINES	FPW	9.5.1 APPENDIX 9A & 9B	N/A	N/A	N/A

TABLE 4.[illegible]5-1 (CONT.)

REG GUIDE	DESCRIPTION	SWEC SYSTEM (TYPICAL EXAMPLE)	FSAR SEC. NO.	FSAR FIGURE NO. (P&ID)	FSAR FIG. NO (LSK)	FSAR DWG PKG
1.133	LOOSE PARTS DETECTION PROGRAM	LPM	4.4.6	4.4-6 4.4-7 4.4-8 4.4-9	4.4-7	N/A
8.8	ALARA (OCCUPATIONAL RADIATION EXPOSURE ARE AS LOW AS REASONABLY ACHIEVABLE)	RMS	12.1	N/A	N/A	N/A
1.68	TARS - TRANSIENT ANALYSIS RECORDING SYSTEM	FWS; CNM	14.2	TABLE 14.2-36 14.2-27	N/A	N/A

Attachment A.

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421.18 (7.2) (7.3) Provide a detailed discussion on the methodology used to establish the technical specification trip setpoints and allowable values for the Reactor Protection System (including Reactor Trip and Engineered Safety Feature channels) assumed to operate in the FSAR accident and transient analyses. Include the following information:

(1) The trip setpoint and allowable value for the technical specifications.

(2) The safety limits necessary to protect the integrity of the physical barriers which guard against uncontrolled release of radioactivity. The safety limits should be the limits established for licensing purposes, for example the technical specification safety limits on minimum critical power ratio (1.06), and reactor coolant system pressure (1325 psig).

(3) The values assigned to each component of the combined channel error allowance (e.g., modeling uncertainties, analytical uncertainties, transient overshoot, response time, trip unit setting accuracy, test equipment accuracy, primary element accuracy, sensor drift, nominal and harsh environmental allowances, trip unit drift), the basis for these values, and the method used to sum the individual errors. Where zero is assumed for an error a justification that the error is negligible should be provided.

(4) The margin (i.e, the difference between the safety limit and the setpoint less the combined channel error allowance).

(5) Identify any trip for which the setpoint and allowable value in the technical specifications will be assigned best estimate values and for which you do not have an analysis of errors and/or uncertainties to confirm that the trip function will occur before the actual value of the measured parameter exceeds that assumed in the plant safety analysis. Provide justification for this nonanalytical approach.

Response

The development process of a Category I setpoint was ~~provided~~ presented to the NRC during the I&C review.

GE141

QUESTION

421.20
(7.2)
(7.3)
(7.4)

Operating reactor experience indicates that a number of failures have occurred in BWR reactor vessel level sensing lines and that in most cases the failures have resulted in erroneously high reactor vessel level indication. For BWRs, common sensing lines are used for feedwater control and as the basis for establishing vessel level channel trips for one or more of the protective functions (reactor scram, MSIV closure, RCIC, LPCI, ADS or HPCS initiation). Failures in such sensing lines may cause a reduction in feedwater flow and consequential defect of a trip within the related protective channel.

If an additional failure, perhaps of electrical nature, is assumed in a protective channel not dependent on the failed sensing line, protective action may not occur or may be delayed long enough to result in unacceptable consequences. This depends on the logic for combining channel trips to achieve protective actions.

Identify each case where a reactor vessel water level tap or sensing line failure concurrent with an additional random single electrical failure induces a transient and precludes the automatic operation of reactor scram and/or engineered safety feature system. For each case identified provide an evaluation which demonstrates how the redundancy or diversity of the plant design provides for reactor scram or safety system operation within acceptable limits. Where manual action is required by the operators discuss the instrumentation and time available for the operator to take such corrective action.

To reduce the consequences of sensing line failures in combination with a single failure in a protection channel not dependent on the failed sensing line, a modification of the protection system logic may be required. Logic configurations which may be considered for NRC approal on this plant are described in the BWR owners group study entitled "Review of BWR Reactor Vessel Water Level Measurement Systems", SLI-8211, prepared by S. Levy Inc.

RESPONSE

A postulated break in an instrument line plus an additional failure is beyond the design basis for this plant; however, an assessment of plant response to this event has been performed on the basis of the following methodology and assumptions.

Methodology

1. Determine the logic for combining channel trips to achieve protective actions.

GE141

2. Identify each case where a reactor vessel water level tap or sensing line failure concurrent with an additional random single electrical failure induces a transient and precludes the automatic operation of a reactor protection and/or an engineered safety feature (ESF) system.

3. For each case identified, demonstrate how the redundancy or diversity of the plant design provides the reactor protection or ESF system operation within acceptable limits. For the worst failure combination scenarios, perform transient analyses to demonstrate that plant safety is not compromised.

Assumptions

1. Instrument reference line failure (break)
2. Single electrical device failure (no power supply failure)
3. ARI operable
4. No operator action.

A review of various failure combinations resulted in the identification of the worst postulated failure path as the failure of division 1 instruments reference leg line (i.e., connected to condensing chamber B21-D004A) combined with a failure "high" of B21-N080C.

The manual selection switch for feedwater controller is assumed to be onthe failed instrument line, and the operator is assumed not to switch control to the other instrument line as would be expected. This causes the feedwater controller to respond to the high water level error signal by reducing the feedwater flow. Following the loss of feedwater, water level will decrease to level 4 initiating a low water level alarm. Water level will further decrease to level 3 initiating a second low water level alarm, and reactor scram will not occur due to the assumed failure. When water level decreases to level 2, a third low water level alarm will be initiated, reactor scram will occur due to Alternate Rod Insertion (ARI). RCIC system will automatically start, and both recirculation pumps will trip. HPCS system is unavailable (tripped) due to the assumed failure.

The core thermal hydraulic analysis using the REDY transient code shows that the water level inside the shroud drops to a minimum of 1.9 feet above the top of the active fuel at 1436 seconds and slowly rises thereafter. Since the core remains covered throughout the transient, no core heatup is expected.

Note: The justification of Assumption 2 is as follows:

Section 4.4.3 of BWROG-8253, "BWR Owners Group Reactor Vessel Water Level Measurement System Report," from T. J. Dente (BWROG) to H. R. Denton (NRC), dated August 13, 1982, stated: "...the ATWS events...indicate that mechanical failures, not instrument failures, in the system...are the largest contributor to core melt.. Events involving electrical failure, which included instrument failures, are less than 0.1% of the total core melt frequency."

QUESTION 421.23
(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:

High drywell temperature does not significantly affect measured reactor water level when reactor pressure is greater than the saturation pressure of water in the water level sensing lines because the vertical drop of the wide range, narrow range and fuel zone range reference and variable leg sensing lines in the drywell are approximately equal. The water level indication is not affected because the comparable vertical drops of the reference and variable leg sensing lines in the drywell result in nearly equal changes in hydrostatic pressure in these lines due to reduced water density at increased drywell temperature.

If reactor pressure decreases to less than the saturation pressure of the water in the water level sensing lines, the water in the lines will flash and boil. The flashing and boiling may result in loss of some of the water in the sensing lines. Loss of water from the sensing lines results in reactor water level measurement error until operator action refills the sensing lines.

Analyses have demonstrated that water level activated safety trips will be initiated for high energy line breaks before reactor pressure decreases to less than the saturation pressure of the water in the sensing lines. Therefore, these safety trips will be initiated before high drywell temperature significantly affects water level measurement.

The NMP2 containment monitoring design consists of eighteen redundant Class 1E temperature elements distributed throughout the Primary Containment: The containment temperature monitoring system constantly scans and selects the highest containment temperatures for control room indication and annunciation. The control room indication of containment temperatures includes metered indication as well as temperature recorders. The control room annunication alerts the operator of high containment temperatures which could lead to possible erroneous level indication.

Long term (i.e. following RPV blowdown and reflooding) water level measurement errors due to flashing and boiling of water in the sensing lines are postulated to occur as a result of multiple failures by the operator to follow established

emergency procedures. The BWR Owners Group (BWROG) has established the position with the NRC that potentially large water level measurement errors resulting from high drywell temperature increase the probability of core melt and that these errors should be minimized and/or eliminated. This position was established with the NRC via the BWROG reports #SLI-8211, titled "Review of BWR Reactor Water Level Measurement System" and #SLI-8218, titled "Inadequate Core Cooling Detection in BWR's" prepared by S. Levy, Inc.

This response provides the results of an evaluation of the NMP2 reactor water level sensing line arrangement in the drywell based upon the criterion accepted on the Shoreham docket. Specifically, the acceptance criterion is that:

> "Following initial reactor water level stabilization after reactor depressurization and assuming the operator fails to properly monitor reactor water level during long term (on the order of hours) post-LOCA conditions, the operator shall receive a low reactor water level alarm before the lower tap is uncovered."

It should be emphasized that the stated criteria is based on the assumption of multiple failures. Under the highly unlikely scenario postulated it is assumed that the operator:

1) fails to properly monitor reactor water level (i.e., the most important post-LOCA parameter),

2) stops all systems providing reactor core inventory,

3) fails to properly monitor drywell temperature and vessel pressure and reflood the reactor in order to recover/restore water level indication, as required by the emergency procedures, when drywell temperature near the instrument lines exceeds that saturation temperature of the reactor vessel, and

4) fails to initiate the drywell spray at the high drywell temperature specified in the emergency procedures.

The evaluation assumes loss of all water in the part of the reference leg sensing line located in the drywell as a result of failure of the operators to follow established emergency procedures. The loss of water from the reference leg is assumed to occur due to high drywell temperature conditions (i.e., flash-off that occurs when the reactor is depressurized and long-term boil-off of water due to drywell temperatures higher than reactor temperatures). The error resulting from flash-off and boil-off is proportional to the vertical elevation change of the reference leg in the drywell. NMP2 has a maximum of 6'-11" ~~6.5 feet~~ vertical elevation of reference legs in the drywell. This evaluation is based on the nominal trip setpoint.

The results of this evaluation indicate that a low reactor water level 2 alarm will be received before the lower instrument tap connected to the alarm is uncovered.

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8/29/84

QUESTION F421.25 (7.2, 7.3, 7.4, 7.5, 7.6, 7.7)

Reg. Guide 1.118, which provides guidance with respect to periodic testing of the reactor protection system (reactor trip, engineered safety features and supporting systems, RCIC) excludes lifting of leads to perform surveillance tests and accepts opening of a breaker to perform surveillance tests only if opening of the breaker causes the trip of the associated channel. Confirm that the Nine Mile Point Unit 2 surveillance tests will conform to the above cited guidance.

RESPONSE

See Table 1.8-1, Regulatory Guide 1.118.

or the use of jumpers

Periodic surveillance testing procedures for the reactor protection system are currently under development. Lifting of leads is not normally utilized in procedure steps unless the procedure would require this action to accomplish the purpose of the procedure and no other method, such as opening a breaker, is possible. Whenever lifted leads are utilized, an analysis will be performed to verify that this is the only practical method available to accomplish the surveillance. Within the body of a procedure specific instructions are given to identify, lift, and replace the leads. Such actions are performed under strict administrative control with independent verification for safety-related systems or components.

or the use of jumpers

or jumpers.

Additionally, ~~the~~ Unit 2 comits to implementing the recomendation of IE Notice NO 84-37 AS DISCUSSED BELOW:
NIAGARA MOHAWK POWER CORPORATION WILL ENDEAVOR TO PERFORM ACTIONS TO FUNCTIONALLY CHECK SAFETY RELATED EQUIPMENT AFTER LIFTING LEADS (TO ACCOMMODATE SURVEILLANCE OR MAINTENANCE) WHENEVER PRACTICAL. A LIST OF CASES WHERE IT IS REQUIRED TO LIFT LEADS FOR AT-POWER TESTING WILL BE PROVIDED TO THE NRC. A LIST WHERE FUNCTIONAL CHECKS

CANNOT BE PERFORMED WILL ALSO BE PROVIDED THE NRC.

QUESTION 421.27

Mode switch contact and mode switch operating mechanism malfunctions have caused inadvertent protective actions. Similar malfunctions could have rendered redundant channels of protective functions inoperable. IE Information Notice 83-42 provided notification of potentially significant events concerning mode switch malfunctions. Section 7.2.1 of the FSAR indicates that the reactor mode switch is used to bypass and enable protective functions, rod withdrawal interlocks and refueling equipment interlocks. Provide a detailed discussion on how the mode switch is incorporated into the overall design, supplemented with detailed drawings and schematics. Please include the following:

(1) Identification of the reactor protection system, rod block, refueling interlock and other functions important-to-safety that are dependent on proper mode switch contact operation.

(2) Identification of the analyzed transients and accidents where credit is taken for the operation of any function identified in (1) above.

(3) The surveillance actions necessary to positively verify mode switch contact positions, detect mode switch contact failures and detect mode switch operating mechanism failures for each function identified in (1) above.

RESPONSE An assessment of the system impact of postulated misoperations for the presently installed mode switch is provided below. The assessment includes an evaluation of the impact of postulated misoperations on the analyses described in Chapter 15. It identifies normal switch contact positions for each mode of operation (RUN, SHUTDOWN, REFUEL, and STARTUP), and summarizes the consequnce should one or more pairs of contacts misoperate. All of these misoperations are detectable by annunciation, instrumentation checks, ~~or~~ AND surveillance testing.

CZ194

Assessment of Effects of Mode Switch Misoperation

NOTE: Each pair of switch contacts is identified by identical digits with the letter C as a suffix on one digit (e.g., 1-1C, 2-2C, etc.). For brevity, only one digit will be used, thus: contact 1, contact 3, etc.

I. Contacts Normally Closed in RUN Position

1.1 IRM Bypass Contacts-3, 5, 19, 21, 35, 37, 51, 53

1.1.1 If any of the above contacts are open in the RUN position the IRM scram function would be enabled and half-scrams or scrams could result if IRM's were upscale or inoperative.

1.1.2. If any of the above contacts are closed in STARTUP, REFUEL, or SHUTDOWN switch positiions, the IRM scram function would be bypassed. This would not be detected immediately but would be evident during weekly channel functional tests because half scrams due to the IRM function could not be induced in the affected channel(s).

1.2 Shutdown Scram Interlock Contacts-9, 25, 41, 57

(Note: These contacts are also normally closed in STARTUP and REFUEL.)

1.2.1 If any of the above contacts are open in the RUN position a scram or half scram will result.

1.2.2 If any of the above contacts are closed in SHUTDOWN, the shutdown trip function of the affected logic circuit would be disabled.

CE194

1.3 APRM Interlock Contacts-11, 27, 28, 43, 44, 59

1.3.1 If any of the above contacts are open in the RUN position, the APRM setdown scram trip function would be enabled and the APRM's would provide half scrams or full scrams at reactor power levels of 15% or greater.

1.3.2 If any of the above contacts are closed in any position but RUN, the APRM setdown scram trip function would be disabled and the trips setpoints would be raised to their high setpoint level of about 113% of reactor rated power.

1.4 Rod Block Interlock Contacts-30, 62

1.4.1 If either of the above contacts are open in the RUN position, an annunciated rod block signal would be sent to the reactor manual control system to prevent removal of more than one control rod.

1.4.2 If either of the above contacts are closed in STARTUP, REFUEL, or SHUTDOWN, there would be an unannunciated permissive for the reactor manual control system to move more than one control rod. In the STARTUP or REFUEL mode, the permissive would be redundant.

1.5 Conclusions

For multiple failures of mode switch contacts which are normally closed in the RUN mode, the principal concerns are:

a. The unannunciated bypass of the IRM scram function in switch positions other than RUN.

b. Failure to cause scram when moving the mode switch to SHUTDOWN.

c. The unannunciated bypass of the APRM setdown scram function in switch positions other than RUN.

d. The unannunciated permissive to move more than one control rod when in the SHUTDOWN mode.

II. Contacts Normally Closed in STARTUP Positions

2.1 MSIV Closure Scram Bypass Contacts-7, 23, 39, 55

(Note: These contacts are also normally closed in REFUEL and SHUTDOWN.)

2.1.1 If any of the above contacts are open in the STARTUP position, the MSIV closure scram trip function would be enabled without immediate operator knowledge, unless one of the two bypass annunciations were to cease. This would require at least two of the four sets of contacts to open.

2.1.2 If any of the above contacts are closed in RUN, an annunciated bypass of the MSIV closure scram trip function would occur.

2.2 Shutdown Scram Interlock Contacts-9, 25, 41, 57

(Note: These contacts are also normally closed in RUN and REFUEL.)

2.2.1 If any of the above contacts are open in the STARTUP position, a scram or half scram will result.

2.2.2 If any of the above contacts are closed in the SHUTDOWN position, the shutdown scram trip function of the affected logic circuit would be disabled.

2.3 Steamline Low Pressure Isolation Trip Bypass Contacts-10, 26, 42, 58

(Note: These contacts are also normally closed in REFUEL and SHUTDOWN.)

2.3.1 If any of the above contacts are open in the STARTUP position, the MSIV isolation-on-low-steamline-pressure function would be enabled. A MSIV isolation trip or half trip would occur. The isolation trip could be followed by a scram or half scram on MSIV closure.

2.3.2 If any of the above contacts are closed in the RUN position, MSIV isolation on low steamline pressure would be bypassed.

2.4 Rod Block Interlock contacts-31, 63

2.4.1 If either of the above contacts are open in the STARTUP position, an annunciated rod block signal would be sent to the reactor manual control system to prevent removal of more than one control rod.

2.4.2 If either of the above contacts are closed when not in STARTUP, there would be an unannunciated permissive for the reactor manual control system to move more than one control rod. In the RUN and REFUEL modes the permissive would be redundant.

2.5 Conclusions

For multiple failures of mode switch contacts which are normally closed in the STARTUP mode, the principal concerns are:

a. The annunciated bypass of the MSIV closure scram trip function in the RUN mode.

b. The unannunciated bypass of the MSIV-isolation-on-low-steam-line pressure function in the RUN mode.

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c. The failure to initiate scram when the mode switch is moved to the SHUTDOWN position.

d. The unannunciated permissive to move more than one control rod in the SHUTDOWN mode.

III Contacts Normally Closed in REFUEL Position

3.1 MSIV Closure Scram Bypass Contacts-7, 23, 39, 55

(Note: These contacts are also normally closed in STARTUP and SHUTDOWN.)

3.1.1 If any of the above contacts are open in the REFUEL position, the MSIV closure scram trip function would be enabled without immediate operator knowledge, unless one of the two bypass annunciations were to cease. This would require at least two of the four sets of contacts to be open.

3.1.2 If any of the above contacts are closed in the RUN position, an annunciated bypass of the MSIV closure scram trip function would occur.

3.2 SDV High Water Level Scram Bypass Contacts-8, 24, 40, 56

(Note: These contacts are also normally closed in SHUTDOWN.)

3.2.1 If any of the above contacts are open in the REFUEL position, the SDV high water level scram trip function would be enabled for the affected logic channel without immediate operator knowledge, unless one of the two bypass annunciations were to cease. This would require at least two of the four sets of contacts to be open.

3.2.2 If any of the above contacts are closed in RUN or STARTUP,

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the SDV high-water-level scram trip bypass would be enabled. (A separate bypass switch for each channel must also be closed to effect the bypass.)

3.3 Shutdown Scram Interlock Contacts-9, 25, 41, 57

(Note: These contacts are also normally closed in RUN and STARTUP)

3.3.1 If any of the above contacts are open in the REFUEL position, a scram or half scram will result.

3.3.2 If any of the above contacts are closed in the SHUTDOWN position, the shutdown scram trip function of the affected logic channel would be disabled.

3.4 Steamline Low Pressure Isolation Trip Bypass Contacts-10, 26, 42 58

(Note: These contacts are also normally closed in STARTUP and SHUTDOWN.)

3.4.1 If any of the above contacts are open in the REFUEL position, the MSIV isolation-on-low-steamline-pressure function would be enabled. A MSIV isolation trip or half trip would occur.

3.4.2 If any of the above contacts are closed in the RUN position, MSIV isolation on low steamline pressure would be bypassed.

3.5 Rod Block Interlock Contacts-29, 61

3.5.1 If either of the above contacts are open in the REFUEL position, an annunciated rod block signal would be sent to the reactor manual control system to prevent removal of more than one control rod.

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3.5.2 If either of the above contacts are closed when not in the REFUEL mode, there would be an unannunciated permissive for the reactor manual control system to move more than one control rod. In the RUN and STARTUP modes, the permissive would be redundant.

3.6 Conclusions

For multiple failures of mode switch contacts which are normally closed in the REFUEL mode, the principal concerns are:

a. The annunciated bypass of the MSIV closure scram trip function in the RUN mode.

b. The unannunciated bypass of the MSIV-isolation-on-low-steamline pressure function in the RUN mode.

c. The failure to cause a scram when the mode switch is moved to the SHUTDOWN position.

d. The unannunciated permissive to move more than one control rod in the SHUTDOWN mode.

e. The annunciated bypass of the SDV high-water-level scram in the RUN or STARTUP mode.

IV. Contacts Normally Closed in SHUTDOWN Position

4.1 Shutdown Scram Reset Controls-1, 2, 17, 18, 33, 34, 49, 50

4.1.1 If any of the above contacts are open in the SHUTDOWN position, the shutdown scram/manual scram logic for the affected logic channel will not be configured to permit the logic channel to be reset after a scram trip.

4.1.2 If any of the above contacts are closed in any position

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except SHUTDOWN, there would be no immediate effect. If both sets of contacts in any logic channel (1 and 2 for logic A1, 17 and 18 for logic B1, etc.) were closed when not in SHUTDOWN, the shutdown scram function would be in the "reset" configuration, and a scram trip would not occur for that logic channel when the mode switch is moved to the SHUTDOWN position.

4.2 MSIV Closure Scram Bypass Contacts-7, 23, 39, 55

(Note: These contacts are also normally closed in STARTUP and REFUEL.)

4.2.1 If any of the above contacts are open in the SHUTDOWN position, the MSIV closure scram trip function would be enabled without immediate operator knowledge, unless one of the two bypass annunciations would cease. This would require at least two of the four sets of contact to be open.

4.2.2 If any of the above contacts are closed in the RUN position, an annunciated bypass of the MSIV closure scram trip function would occur.

4.3 SDV High Water Level Scram Bypass Contacts-8, 24, 40, 56

(Note: These contacts are also normally closed in REFUEL.)

4.3.1 If any of the above contacts are open in the SHUTDOWN position, the SDV high water level scram trip function would be enabled for the affected logic channel without immediate operator knowledge, unless one of the two bypass annunciations were to cease. This would require at least two of the four sets of contacts to be open.

4.3.2 If any of the above contacts are closed in RUN or

STARTUP, the SDV high water level scram trip bypass would be enabled. (Closure of a separate bypass switch for each channel would be required to complete the bypass.

4.4 Steamline Low Pressure Isolation Trip Bypass Contacts-10, 26, 42, 58

(Note: These contacts are also normally closed in STARTUP and REFUEL.)

4.4.1 If any of the above contacts are open in the SHUTDOWN position, the MSIV isolation-on-low-steamline-pressure function would be enabled. A MSIV isolation trip or half trip would occur.

4.4.2 If any of the above contacts are closed in RUN, MSIV isolation on low steamline pressure would be bypassed.

4.5 Conclusions

For multiple failures of mode switch contacts which are normally closed in the SHUTDOWN mode, the principal concerns are:

a. The annunciated bypass of the MSIV closure scram trip function in the RUN mode.

b. The unannunciated bypass of the MSIV-isolation-on-low-steamline pressure function in the RUN mode.

c. The annunciated bypass of the SDV high-water-level scram in the RUN or STARTUP mode.

V. Summary and Conclusions

A. All failure modes for the mode switch contacts where contacts open that should be closed would result in scrams or half scrams depending on the number of contacts that are open. At the same

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time, for conditions of operation where steamline pressure is low, isolation of the main steamlines would occur.

B. In the "STARTUP", "REFUEL", and "SHUTDOWN" positions of the mode switch, closures of contacts that should be open (3,5,19,21, 35,37,51,53) would result in a bypass of the IRM scram function in one or more of the RPS channels. Closure of contacts 11, 27, 28, 43, 44, 59, would result in raising the setpoint of the normally setdown APRM high flux scram function from 15% to 113% in one or more of the RPS/NMS channels.

C. In item B above, although the mode switch failure, (i.e., contacts closing), would not be immediately apparent to the plant operator, the failure would be detected during the weekly IRM and APRM channel functional tests. If these tests were performed prior to the power increase and after transferring the mode switch to the "STARTUP" position, then the IRM channel functional tests would detect the IRM failures because no half scram would result. The proposed technical specification requirement will be that the IRM channel functional test and the APRM channel functional test be performed within 24 hours prior to startup, if it has not been performed in the previous seven days. Weekly surveillance would be required for the case whereby the "hot standby" (STARTUP position) condition is maintained for long periods of time. INSERT A

D. In the "RUN" position of the mode switch, closures of contacts 7, 23, 39, 55 would result in the bypass of one or more RPS trip channels related to the MSIV closure scram functions. Closure of contacts 10, 26, 42, 58 would result in the bypass of one or more NSSSS trip channels related to the steamline low pressure isolation function. Concurrent with the incorrect mode switch contact closures, there would be annunciations that one or more of the RPS MSIV closure scram trip channels have been bypassed.

INSERT A

ALSO, ONCE A REFUELING CYCLE AFTER THE MODE SWITCH IS PLACED IN THE STARTUP POSITION A CHANNEL FUNCTION TEST OF THE IRM'S HIGH FLUX TRIP WILL BE PERFORMED.

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E. Closure of contacts 9, 25, 41, 57 can bypass the "SHUTDOWN" mode scram function. If the contacts remain closed during and after transfer of the mode switch to the "SHUTDOWN" position, such closed contacts would not allow a scram to occur from positioning of the switch. That is, only a half scram or no scram would result. This fact would be immediately apparent to the operator. Mannual scraming of the plant is accomplished by depressing the manually scram switch. The ability to scram the plant from the mode switch is only a secondary effect, and one of several backup alternates to the scram pushbutton.

F. In the "SHUTDOWN" mode, closure of mode switch contacts 29, 30, 31, 61, 62, 63 would remove the normal rod withdrawal block restriction associated with this mode. This fact would be apparent to the operator because the window for the normal rod withdrawal block annunciator would be extinguished, and its change of state would alert the operator. The manual positioning of rods is under strict procedural controls. The rod block positioning restrictions are only backups to those controls. Additionally, the operator would become aware of the situation via standard technical specification driection by verifying this rod block by attempting to withdraw a second rod after the first one is withdrawn.

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VI. Evaluation of the Effects of Mode Switch Misoperation on Chapter 15 Analyses.

The potential impacts of the effects of mode switch misoperation on the analyses of transients and accidents presented in Chapter 15 were evaluated. The focus was on certain specific events because of previously expressed NRC concerns with those events or because the events might impact the limiting transients. These specific events were classified into two groups according to the consequences of mode switch misoperation.

1. Group 1

The events in Group 1 include:

a. The abnormal startup of an idle recirculation loop.

b. The failure of the recirculation flow controller with increasing flow.

c. A rod drop accident.

These are events for which the concern is related to the bypass of the scram function of the intermediate range monitor (IRM) while the mode switch is in the "STARTUP," "REFUEL," or "SHUTDOWN" positions. This would also raise the scram setpoint of the average power-range monitor (APRM) from the 15% "startup" value to the 118% "run" value, which corresponds to the analytical limit of 121% used for the analyses of Chapter 15 transients and accidents.

None of the Chapter 15 analyses of the events in Group 1 takes credit for either the IRM scram function or the APRM scram function with the setpoint setdown to the 15-to-25% level. Events a and b of Group 1 were analyzed from a "RUN"-mode power condition since the Chapter 15 analyses are initiated from about 56% power and 40% core flow. In the "RUN" mode, the IRM trips are bypassed and the APRM flux scram-setpoint is approximately 118% (121% analytical limit). The rod drop accident analysis was initiated from 0% power, (50% rod density); consequently, the mode switch would be in the "STARTUP" position.

No impact would result from the misoperation of the mode switch in the "REFUEL" or "SHUTDOWN" modes.

a. For the analysis of the abnormal recirculation-loop startup transient, no credit was taken for the flow reference in the scram for high neutron flux. The high neutron flux setpoint of 121% was used. The Analysis of this event was initiated from a power level significantly in excess of where recirculation-loop startups would

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normally originate and corresponding to the mode switch in the "RUN" mode. At lower power levels, the consequences of the event would be less severe; consequently, the impact of the mode switch misoperation on the analysis of this event is of no significant consequence.

The initiation of an abnormal recirculation-loop startup transient when the mode switch is in the "STARTUP" position would also be of no consequence since operating procedures would require the initial power level to be less than 15%. The resulting power increase probably would not cause a scram. If the resulting power level were in excess of technical specification requirements related to power, pressure, and core flow, the operator would take corrective action in accordance with those requirements.

b. The Chapter 15 analyses of the recirculation flow-controller failure with increasing flow were initiated from a 55% power and 35.7% core flow conditions, with a 121% flux scram terminating the power excursion. Similar events originating from the startup power range of 0 to 15% power would be of lesser consequence. Also, at this low power level, normal operating procedures would infer minimum pump speed with individual loop operation. These operating conditions would lessen the effect of a single-loop flow increase and would preclude the event of flow control failing with increasing flow on both loops.

c. The analysis in Chapter 15 of the rod drop event only takes credit for the 121% APRM trip and takes no credit for the IRM scram function. The event, as analyzed from the 0% power level, is terminated by the Doppler effect and is of significance only below about 2 to 3% power. At high power levels, the rod drop would be less of a problem because of the influence of the resulting steam voids in the core on the local high reactivity.

2. Group 2

The events in Group 2 include:

a. The inadvertent closure of the main steam isolation valve.

b. The loss of an auxiliary power transformer.

c. The break of a main steam line outside the containment.

d. The failure in the open position of the steam pressure controller.

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These are events for which the concern is either the bypass of the main steamline isolation function due to low steamline pressure by the nuclear steam supply shutoff system (NS^4) in the "RUN" mode or the loss of the position scram function of the MSIVs in the "RUN" mode. Only the isolation function that should result whenever the turbine-inlet steamline pressure drops below the (analysis) setpoint level of approximately 720 psig is of concern. No other isolation functions of the NS^4 are impacted by the potential mode switch misoperations.

a. The analysis of the MSIV closure event in Chapter 15 does take credit for the scram initiated from limit switches of the MSIV while the mode switch is in the "RUN" mode. Potential mode switch misoperation could cause this scram function to be bypassed while the mode switch is in the "RUN" position. However, this bypass would be annunciated in the control room. The operating procedures would require corrective action since the technical specification requirement that all four channels for the MSIV-closure trip function be operable in the "RUN: mode would be violated. Depending upon the number of inoperable channels, the affected channels and at least one trip system of the reactor protection system (RPS) would have to be placed in the tripped condition within one hour. If both RPS trip systems were affected, the plant would have to be placed in the "STARTUP" condition within 6 hours.

b. The consequences of the auxiliary power, as analyzed in Chapter 15, are also not affected by any mode switch misoperation. The scram and isolation that occur at about 2 seconds (or later) are a direct result of the loss of power to the RPS motor-generator sets and the subsequent disconnection of all power to the loads on the RPS bus.

c. The analysis of the main steamline break outside of the containment does not take credit either for the low steamline isolation signal that would probably result from low steamline pressure or for the scram from MSIV closure. In this analysis, the event is initiated at the Level 3 scram to start out with a minimum inventory. At about 0.5 seconds into the event the isolation is assumed to be initiated because of high steamline flow. Although this is not addressed in the analysis, a level-8 high-water turbine trip would be expected due to sudden depressurization.

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d. Failure of the steam pressure controller in the open position would result in a level-8 high-water level turbine trip, which would initiate a scram and a recirculation pump trip. Further depressurization would be limited to the capacity of the turbine bypass. Since an annunciation in the control room would have alerted to the bypass of the isolation function, the operator would be prepared to actuate MSIV closure manually should this event occur.

Conclusions from these evaluations are that all misoperations of the mode switch are detectable by one or more of the following means.

a. The operator would be immediately aware of a problem because of the annunciation of bypasses that should not exist for the given postion of the mode switch. All mode switch misoperations that might impact the severity of consequences of transients and accidents analyzed in Chapter 15 are in this category. Hence, the probability of a transient occuring before the operator takes corrective action would be extremely low.

b. The operator would be immediately aware of a problem in the RPS because of scrams or half scrams, which are also annunciated.

c. The remaining modes of mode switch misoperation would be detected during the weekly channel functional tests of the NMS channel inputs to the RPS. If these tests were performed prior to the power increase and after the transfer of the mode switch to the "STARTUP" position, the IRM channel functional tests would detect the failures because no half scram would result.

QUESTION F421.28 (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).

RESPONSE

See revised Section 7.3.2.1.2.1.

A review of ESF system (ECCS, RHR, NSSS) documents current as of January 1984 for Nine Mile Point - Unit 2 (NMP2) was performed to identify any ESF system reset control action that conflicts with the guidance of IE Bulletin 80-06. NMP2's automatic depressurization system (ADS) reset controls return each ADS safety/relief valve to its closed position. This deliberate operator action closing the ADS safety/relief valves B22-F013 C, H, K, M, N, R, and U to prevent or limit inadvertent reactor depressurization is considered an allowed exception to IE 80-06 compliance. Besides this exception, no deviation from the guidance indicated in IE Bulletin 80-06 was found.

In addition, RCIC (not considered an ESF) was reviewed and found to be in conformance with the guidance of IE Bulletin 80-06.

Also, the testing as required by IE Bulletin 80-06 item 2 will be conducted as part of the initial testing phase.

QUESTION F421.34 (7.4)

Section 7.4.1.4 of the FSAR provides information on the Remote Shutdown System (RSS). Attachment 1 provides the instrumentation and Control Systems Branch (ICSB) guidance for remote shutdown capability. The attachment provides guidance for meeting the requirements of GDC 19. Provide supplemental information to identify the extent that the design of the RSS at Nine Mile Point - Unit 2 conforms to the guidance provided in Attachment 1. Include the following information in your discussion using drawings as appropriate:

a) Design criteria for the remote control station equipment including the transfer switches and separation requirements for redundant functions.

b) Discuss the separation arrangement between safety related and nonsafety-related instrumentation and controls on the auxiliary shutdown panel.

c) Location of transfer switches and the remote control stations.

d) Description of isolation, separation and transfer/override provisions. This should include the design basis for preventing electrical interaction between the control room and remote shutdown equipment.

e) Description of the administrative and procedural control features to both restrict and to assure access, when necessary, to the displays and controls located outside the control room.

f) Description of any communication systems required to coordinate operator actions, including redundancy and separation.

g) Means for ensuring that cold shutdown can be accomplished.

h) Description of control room annunciation of remote control or override status of devices under local control.

i) Discuss the proposed start-up test program to demonstrate remote shutdown capability in accordance with the guidance provided in R.G. 1.68.2.

j) Discuss the testing to be performed during plant operation to verify the capability of maintaining the plant in a safe shutdown condition from outside the control room.

k) Discuss the equipment classification using the guidelines contained in FSAR Table 3.2-1.

RESPONSE

The response to Items a, b, c, and d is as follows:

Unit 2 compliance with the guidance contained in Attachment 1 is described below:

1. The remote shutdown panel (RSP) is designed to achieve and maintain hot shutdown in the event the control room is inaccessible. This is achieved by the use of redundant, safety grade instrumentation identical (in most all cases) to that used in the control room. Additionally, some nonsafety-related indicators and recorders are provided for operation use. INSERT A

2. See Item 1. INSERT B

3. No jumping, rewiring, circuit disconnection, or manual action (in locations other than the RSP) is used to achieve the desired shutdown condition.

4. The design of the RSP is such that cold shutdown is achieved using safety grade, redundant instrumentation.

5. Loss of offsite power will not negate shutdown capability since power is supplied by reliable safety grade power sources.

6. Transfer of control to the RSP does not disable any ESF function or change the operating status of any equipment. The RHR isolation valves on the RSP are of a spring return type.

7. The access to the remote shutdown room is controlled at all times and the transfer switches are the lockable type. See response to Item e below.

8. Design of the RSP is under evaluation for conformance to the requirements of Appendix R to 10CFR50.

INSERT A

AND REDUNDANT SAFETY GRADE CONTROL CIRCUITS.

INSERT B

AS A RESULT OF THE NMP2 APPENDIX R SPURIOUS ANALYSIS STUDY PROVISIONS HAVE BEEN MADE TO DISCONNECT THE AUTOMATIC INTERLOCKS BETWEEN the control/relay room AND THE SAFETY RELATED EQUIPMENT REQUIRED FOR SAFE SHUTDOWN. THE DISCONNECT SWITCHES WOULD PREVENT SPURIOUS ACTUATION OF SAFETY RELATED EQUIPMENT RESULTING FROM AUTOMATIC SIGNALS GENERATED FROM the control/relay room. THESE DISCONNECT SWITCHES INSURE TOTAL MANUAL CONTROL FROM THE REMOTE SHUTDOWN PANEL.

THE TRANSFER OF CONTROL FROM the control/relay room TO THE REMOTE SHUTDOWN PANEL WILL BE PEFORMED IN SUCH A WAY AS NOT TO CAUSE SPURIOUS ACTUATION OF SAFETY RELATED EQUIPMENT. THE TRANSFER OF CONTROL FROM the control/relay room TO REMOTE SHUTDOWN WILL NOT CAUSE ANY CHANGE IN EQUIPMENT STATUS. UPON COMPLETION OF THE CONTROL TRANSFER TO THE REMOTE SHUTDOWN PANEL, THE SAFETY RELATED EQUIPMENT REQUIRED FOR SAFE SHUTDOWN WILL ONLY OPERATE UNDER MANUAL CONTROL. PROCESS INDICATION PROVIDED ON THE REMOTE SHUTDOWN PANEL IS SUFFICIENT FOR THE OPERATOR TO ACHIEVE AND MAINTAIN HOT SHUTDOWN.

Additionaly, specific procedures and operator training will be provided to ensure safe operations from the remote shutdown panel

e. Access to the remote shutdown system controls will be controlled by the plant security system. Access will be restricted as with other vital areas. In the event of the failure of the card reader, access will be possible by use of metal keys. Additionally, key lock switches requiring the use of metal keys are utilized for panel transfer/override functions. These keys will be administratively controlled according to key control procedures and readily available to both the Control Room Operator and the Shift Supervisor in the event of a control room evacuation.

f. Use of communications to coordinate operator actions is not required as all functions to safely shut down the plant can be performed independently from either the control room or the remote shutdown system controls.

g. A description of how cold shutdown is achieved utilizing the remote shutdown panel is contained in Section 7.4.1.4.

h. A description of control room annunciation when transfer switches are changed to the emergency position is contained in Section 7.4.1.4.

i. A separate startup test procedure, as described in test abstracts, Table 14.2, will be performed to demonstrate the capability of the remote shutdown system to safely shut down the plant within guidelines provided by Reg. Guide 1.68.2.

j. Instrumentation and controls associated with the remote shutdown system shall be calibrated and functionally verified by surveillance testing as required in technical specifications. Remote shutdown system design is such that functional testing of systems verifies the operational capability to provide remote shutdown. Additionally, periodic testing of the transfer switches will be performed to verify control functions.

k. See revised Table 3.2-1.

421.34 ATTACHMENT 1
ICSB GUIDANCE FOR THE INTERPRETATION OF GENERAL DESIGN CRITERIA 19 CONCERNING REQUIREMENTS FOR REMOTE SHUTDOWN STATIONS

A. BACKGROUND

GDC 19 requires that equipment at appropriate locations outside the control room be provided to achieve a safe shutdown of the reactor. Recent reviews of remote shutdown station designs have demonstrated that some designs cannot accommodate a single failure in accordance with the guidance of SRP Section 7.4 (Interpretation of GDC-19). The following provides supplemental guidance for the implementation of the requirements of GDC-19 concerning remote shutdown stations. Requirements for remote shutdown capability following a fire are detailed in Appendix R to 10CFR50. It should be noted that although GDC 19 and Appendix R requirements are complementary, the potential exists that modifications to bring a design into conformance with GDC 19 will violate Appendix R criteria and vice versa. For example, remote manual devices for a second division of instrumentation and controls added to satisfy single failure requirements would not be acceptable if the added devices were located in the same fire area as existing transfer switches in the redundant division. In addition, transfer switches added to isolate the remote shutdown equipment from the control room fire area would not be acceptable if they disable ESF actuation, unless this is done in accordance with Item B6 below. The acceptability of remote shutdown station designs given a fire is determined by the Auxiliary Systems Branch (ASB) as outlined in Section 9.5.1 of the SRP.

B. ICSB GUIDANCE

To Meet GDC-19 (As Interpreted In SRP Section 7.4)

1) The design should provide redundant safety grade capability to achieve and maintain hot shutdown from a location or locations remote from the control room, assuming no fire damage to any required systems and equipment and assuming no accident has occurred. The remote shutdown station equipment should be capable of maintaining functional operability under all service conditions postulated to occur (including abnormal environments such as loss of ventilation), but need

not be environmentally qualified for accident conditions unless environmental qualification is required for reasons other than remote shutdown. The remote shutdown station equipment, including indicators, should be seismically qualified.

2) Redundant instrumentation (indicators) should be provided to display to the operator(s) at the remote shutdown location(s) those parameters which are relied upon to achieve and verify that a safe shutdown condition has been attained.

3) Credit may be taken for manual actions (exclusive of continuous control) of systems from locations that are reasonably accessible from the Remote Shutdown Stations. Credit may not be taken for manual actions involving jumpering, rewiring, or disconnecting circuits.

4) The design should provide redundant safety grade capability for attaining subsequent cold shutdown through the use of suitable procedures.

5) Loss of offsite power should not negate shutdown capability from the remote shutdown stations. The design and procedures should be such that following activation of control from the remote shutdown location, a loss of offsite power will not result in subsequent overloading of essential buses or the diesel generator. Manual restoration of power to shutdown loads is acceptable provided that sufficient information is available such that it can be performed in a safe manner.

6) The design should be such that if manual transfer of control to the remote location(s) disables any automatic actuation of ESF equipment, this equipment can be manually placed in service from the remote shutdown station(s). Transfer to the remote location(s) should not change the operating status of equipment.

7) Where either access to the remote shutdown station(s) or the operation of equipment at the station(s) is dependent upon the use of keys (e.g., key lock switches) access to these keys shall be administratively controlled and shall not be precluded by the event necessitating evacuation of the control room.

8) The design should comply with the requirements of Appendix R to 10 CFR 50.

QUESTION F421.36 (7.5) 1.10

The NRC staff has recently issued Revision 2 to Regulatory 1.12
Guide 1.97, "Instrumentation for Light-Water-Cooled Nuclear 1.13
Power Plants to Assess Plant and Environs Conditions During 1.14
and Following an Accident" via Supplement 1 to NUREG-0737. 1.15
This Reg. Guide revision reflects a number of major changes 1.16
in post-accident instrumentation. Supplement 1 to 1.18
NUREG-0737 includes specific Reg. Guide 1.97 implementation 1.19
requirements for plants in the operating license review 1.20
stage.

Provide a description of how the Nine Mile Point Unit 2 1.21
design conforms to the provisions of Reg. Guide 1.97, 1.22
Revision 2. This description should be in the form of a 1.24
table that includes the following information for each Type 1.25
A, B, C, D, E variable shown in Regulatory Guide 1.97: 1.26

(1) instrument range 1.28

(2) environmental qualification (as stipulated in guide or 1.29
state criteria) 1.30

(3) seismic qualification (as stipulated in guide or state 1.31
criteria) 1.32

(4) quality assurance (as stipulated in guide or state 1.33
criteria)

(5) redundancy and sensor(s) location(s) 1.34

(6) power supply (e.g., Class 1E, non-Class 1E, battery 1.35
backed)

(7) location of display (e.g., control room board, SPDS, 1.36
chemical laboratory 1.37

Deviations from the guidance in Reg. Guide 1.97 should be 1.39
explicitly shown, and supporting justification or 1.40
alternatives should be presented. 1.41

RESPONSE 1.42

Information will be provided by the end of the 1st Quarter of 1984.

See Table 7.5 —.

TABLE A. (NRC QUESTION 421.36)

SWEC ID NUMBER	GE-NED ID NUMBER	PARAMETER DESCRIPTION	R.G. 1.97 REV 3 PARAMETER VARIABLE	R.G. 1.97 REV 3 PARAMETER CLASSIFICATION	SENSOR LOCATION	SENSOR INSTR. RANGE	QUALIFICATION SEISMIC	QUALIFICATION ENVIRONMENTAL	QUALITY ASSURANCE CLASSIFICATION	POWER SUPPLY	DISPLAY LOCATION NOTE 3	NOTES
	B13-D193	POWER RNG FLUX LEVEL	B 1a.	1	CORE	.5 – 125% PWR	YES	YES	II	NON-1E	P603	1
		AVERAGE PWR RNG FLUX LVL	B 1b.	1	N/A	0 – 125% PWR	NO	NO	II	NON-1E	P603	2
	C51-N002A thru H	INTERMEDIATE RNG FLUX LEVEL	B 1c.	1	CORE	40×10^{-5} – 126 % PWR	YES	YES	II	NON-1E	P603	—
	C51-N001A thru D	SOURCE RNG FLUX LEVEL	B 1d.	1	CORE	.1 – 1×10^{6} CPS	YES	YES	II	NON-1E	P603	—
		CONTROL ROD POSITION	B 2	3	CORE	WITHDRAWN OR SCRAM	YES	YES	II	NON-1E	P603	—
		RX COOLANT BORON CONC.	B 3	3	UNIT 1 H.P. LAB.	? (Lab)	(Lab)	(Lab)	II	NON-1E	—	4
2ISC*LT13A	B22-N044A	REACTOR VESSEL LEVEL -A (FUEL ZONE)	B 4a.	1	RX BLDG (SEC CONTMT)	230.69 – 430.69"	YES	YES	I	DIV 1	P601	5
2ISC*LT13B	B22-N044B	REACTOR VESSEL LEVEL -B (FUEL ZONE)	B 4.b.	1	RX BLDG (SEC CONTMT)	230.69 – 430.69"	YES	YES	I	DIV 2	P601	5
N/A	N/A	CORE TEMPERATURE	B 5	1	—	—	—	—	—	—	—	6
2ISC*PT6A	B22-N062A	REACTOR VESSEL PRESSURE -A	B 6a.	1	RX BLDG (SEC CONTMT)	0-1500 PSIG	YES	YES	I	DIV 1	P601	—
2ISC*PT6B	B22-N062B	REACTOR VESSEL PRESSURE -B	B 6b.	1	RX BLDG (SEC CONTMT)	0-1500 PSIG	YES	YES	I	DIV 2	P601	—

TABLE A. (NRC QUESTION 421.36)

SWEC ID NUMBER / GE-NED ID NUMBER	PARAMETER DESCRIPTION	R.G. 1.97 REV 3 PARAMETER: VARIABLE	R.G. 1.97 REV 3 PARAMETER: CLASSIFICATION	SENSOR: LOCATION	SENSOR: INSTR. RANGE	QUALIFICATION: SEISMIC	QUALIFICATION: ENVIRONMENTAL	QUALITY ASSURANCE CLASSIFICATION	POWER SUPPLY	DISPLAY LOCATION NOTE 3	NOTES
2CMS*PT2A	DRYWELL PRESSURE -A	B7a.	1	RX BLDG (SEC CONTMT)	0-150 PSIG	YES	YES	I	DIV 1	P601	—
2CMS*PT2B	DRYWELL PRESSURE -B	B7b.	1	RX BLDG (SEC CONTMT)	0-150 PSIG	YES	YES	I	DIV 2	P898	—
2CMS*PT7A	SUPPRESSION CHAMBER PRESS-A	B7c.	1	RX BLDG (SEC CONTMT)	0-150 PSIG	YES	YES	I	DIV 1	P601	—
2CMS*PT7B	SUPPRESSION CHAMBER PRESS-B	B7d.	1	RX BLDG (SEC CONTMT)	0-150 PSIG	YES	YES	I	DIV 2	P898	—
SEE NOTE 7	DRYWELL SUMP LEVEL	B8	1	—	—	—	—	—	—	—	7
2CMS*PT1A	PRIMARY CONTAINMENT PRESSURE -A	B9a.	1	RX BLDG (SEC CONTMT)	-5 TO +5 PSIG	YES	YES	I	DIV 1	P601	8
2CMS*PT1B	PRIMARY CONTAINMENT PRESSURE -B	B9b.	1	RX BLDG (SEC CONTMT)	-5 TO +5 PSIG	YES	YES	I	DIV 2	P601/ P898	8
2AAS*HCV 134, 135	PRIMARY CONTAINMENT VLV ISOLATION - AAS	B10a1.	1	N/A	N/A	YES	YES	I	DIV 1	P851	—
2AAS*HCV 136, 137	PRIMARY CONTAINMENT VLV ISOLATION - ASS	B10a2.	1	N/A	N/A	YES	YES	I	DIV 2	P851	—
2CCP*MOV 15A,B; 17A,B; 124; 265	PRIMARY CONTAINMENT VLV ISOLATION - CCP	B10b1.	1	N/A	N/A	YES	YES	I	DIV 1	P602/ P873	37
2CCP*MOV 16A,B; 94A,B; 122; 273	PRIMARY CONTAINMENT VLV ISOLATION - CCP	B10b2.	1	N/A	N/A	YES	YES	I	DIV 2	P602/ P873	37

TABLE A. (NRC QUESTION 421.36)

SWEC ID NUMBER / GE-NED ID NUMBER	PARAMETER DESCRIPTION	R.G. 1.97 REV 3 PARAMETER		SENSOR		QUALIFICATION		QUALITY ASSURANCE CLASSIFICATION	POWER SUPPLY	DISPLAY LOCATION NOTE 3	NOTES
		VARIABLE	CLASSIFICATION	LOCATION	INSTR. RANGE	SEISMIC	ENVIROMENTAL				
2CMS & SOV 24A,C; 26A,C; 32A; 33A; 34A; 35A; 60A,B; 62A,B	PRIMARY CONTAINMENT ISOLATION -CMS	B10c1	1	N/A	N/A	YES	YES	I	DIV 1	P873	~
2CMS & SOV 24B,D; 26B,D; 32B; 33B; 34B; 35B; 61A,B; 63A,B	PRIMARY CONTAINMENT ISOLATION -CMS	B10c2	1	N/A	N/A	YES	YES	I	DIV 2	P875	~
2CPS & AOV 104,105,110,111 & SOV 119,120	PRIMARY CONTAINMENT ISOLATION -CPS	B10d1	1	N/A	N/A	YES	YES	I	DIV 1	P873	~
2CPS & AOV 106,107,108,109 & SOV 121,122	PRIMARY CONTAINMENT ISOLATION -CPS	B10d2	1	N/A	N/A	YES	YES	I	DIV 2	P875	~
2CSH & AOV 103 & MOV 105,107,111,118 / E22-F005 -F012, F004, F023, F015	PRIMARY CONTAINMENT ISOLATION -CSH	B10e	1	N/A	N/A	YES	YES	I	DIV 3	P601	~
2CSL & AOV 101 & MOV 104, 112 / E21-F006 -F005, F001	PRIMARY CONTAINMENT ISOLATION - CSL	B10f	1	N/A	N/A	YES	YES	I	DIV 1	P601	~
2DER & MOV 120, 131	PRIMARY CONTAINMENT ISOLATION -DER	B10g1	1	N/A	N/A	YES	YES	I	DIV 1	P873	~
2DER & MOV 119, 130	PRIMARY CONTAINMENT ISOLATION -DER	B10g2	1	N/A	N/A	YES	YES	I	DIV 2	P873	~
2DFR & MOV 120, 139	PRIMARY CONTAINMENT ISOLATION -DFR	B10h1	1	N/A	N/A	YES	YES	I	~~DIV 1~~	P873	~

TABLE A .. (NRC QUESTION 421.86)

SWEC ID NUMBER / GE-NED ID NUMBER	PARAMETER DESCRIPTION	R.G. 1.97 REV 3 PARAMETER: VARIABLE	R.G. 1.97 REV 3 PARAMETER: CLASSIFICATION	SENSOR: LOCATION	SENSOR: INSTR. RANGE	QUALIFICATION: SEISMIC	QUALIFICATION: ENVIRONMENTAL	QUALITY ASSURANCE CLASSIFICATION	POWER SUPPLY	DISPLAY LOCATION NOTE 3	NOTES
2OFR * MOV 121, 140	PRIMARY CONTAINMENT ISOLATION - OFR	B10h2,	1	N/A	N/A	YES	YES	I	DIV 2	P873	~
2FPW * SOV 218, 220	PRIMARY CONTAINMENT ISOLATION - FPW	B10f1,	1	N/A	N/A	YES	YES	I	DIV 1	P849	36
2FPW * SOV 219, 221	PRIMARY CONTAINMENT ISOLATION - FPW	B10j2,	1	N/A	N/A	YES	YES	I	DIV 2	P849	36
2FWS * MOV 21A, B / B22-F065A, B	PRIMARY CONTAINMENT ISOLATION - FWS	B10k1.	1	N/A	N/A	YES	YES	I	DIV 1	P603	~
2FWS * MOV 23A, B / B22-F032A, B	PRIMARY CONTAINMENT ISOLATION - FWS	B10k2.	1	N/A	N/A	YES	NO	II	NON-1E	P603	9
2HCS * MOV 1A, 2A, 3A, 4A, 5A, 6A	PRIMARY CONTAINMENT ISOLATION - HCS	B10L1,	1	N/A	N/A	YES	YES	I	DIV 1	P873	~
2HCS * MOV 1B, 2B, 3B, 4B, 5B, 6B	PRIMARY CONTAINMENT ISOLATION - HCS	B10L2.	1	N/A	N/A	YES	YES	I	DIV 2	P875	~
2IAS * SOV 164, 166, 167, 168	PRIMARY CONTAINMENT ISOLATION - IAS	B10m1,	1	N/A	N/A	YES	YES	I	DIV 1	P601/P851	38
2IAS * SOV 165, 180, 184, 185	PRIMARY CONTAINMENT ISOLATION - IAS	B10m2.	1	N/A	N/A	YES	YES	I	DIV 2	P601/P851	38
2ICS * MOV 121, 122, 126, 136, 143, 164 * MOV 156, 157 / E51-F064, F068, F013, F031, F019, F080 E51-F065, F066	PRIMARY CONTAINMENT ISOLATION - ICS	B10n1,	1	N/A	N/A	YES	YES	I	DIV 1	P601	~

TABLE A. (NRC QUESTION 421.36)

SWEC ID NUMBER / GE-NED ID NUMBER	PARAMETER DESCRIPTION	R.G. 1.97 REV 3 PARAMETER: VARIABLE	R.G. 1.97 REV 3 PARAMETER: CLASSIFICATION	SENSOR: LOCATION	SENSOR: INSTR. RANGE	QUALIFICATION: SEISMIC	QUALIFICATION: ENVIRONMENTAL	QUALITY ASSURANCE CLASSIFICATION	POWER SUPPLY	DISPLAY LOCATION NOTE 3	NOTES
2ICS # MOV 128, 148, 170 / E51-F063, F086, F076	PRIMARY CONTAINMENT ISOLATION - ICS	$B10_{N2}$	1	N/A	N/A	YES	YES	I	DIV 2	P601	~
2LMS # SOV 153, 157 /	PRIMARY CONTAINMENT ISOLATION - LMS	$B10_{P1}$	1	N/A	N/A	YES	YES	I	DIV 1	P873	~
2LMS # SOV 152, 156. /	PRIMARY CONTAINMENT ISOLATION - LMS	$B10_{P2}$	1	N/A	N/A	YES	YES	I	DIV 2	P875	~
2MSS # MOV 112, 208 / B22-F019, N/A	PRIMARY CONTAINMENT ISOLATION - MSS	$B10_{q1}$	1	N/A	N/A	YES	YES	I	DIV 1	P602	~
2MSS # HYV 7A, B, C, D / B22-F028 A, B, C, D	PRIMARY CONTAINMENT ISOLATION - MSS	$B10_{q2}$	1	N/A	N/A	YES	YES	I	RPS DIV 1	P602	~
2MSS # MOV 111 / B22-F016	PRIMARY CONTAINMENT ISOLATION - MSS	$B10_{q3}$	1	N/A	N/A	YES	YES	I	DIV 2	P602	~
2MSS # HYV 6A, B, C, D / B22-F022 A, B, C, D	PRIMARY CONTAINMENT ISOLATION - MSS	$B10_{q4}$	1	N/A	N/A	YES	YES	I	RPS DIV 2	P602	~
/ C51-J004A, B, C, D, E	PRIMARY CONTAINMENT ISOLATION - NMS	$B10_{\mu}$	1	N/A	N/A	YES	NO	II	NON-1E	P607	10
2RCS # SOV 65A, B; 66A, B; 67A, B; 68A, B; 2RCS # SOV 104 / B35-F020	PRIMARY CONTAINMENT ISOLATION - RCS	$B10_{S1}$	1	N/A	N/A	YES	YES	I	DIV 1	P602	~
2RCS # SOV 79A, B; 80A, B; 81A, B; 83A, B; 2RCS # SOV 105 / B35-F019	PRIMARY CONTAINMENT ISOLATION - RCS	$B10_{S2}$	1	N/A	N/A	YES	YES	I	DIV 2	P602	~

TABLE A. (NRC QUESTION 421.36)

SWEC ID NUMBER / GE-NED ID NUMBER	PARAMETER DESCRIPTION	R.G. 1.97 REV 3 PARAMETER: VARIABLE	R.G. 1.97 REV 3 PARAMETER: CLASSIFICATION	SENSOR: LOCATION	SENSOR: INSTR. RANGE	QUALIFICATION: SEISMIC	QUALIFICATION: ENVIRONMENTAL	QUALITY ASSURANCE CLASSIFICATION	POWER SUPPLY	DISPLAY LOCATION NOTE 3	NOTES
2RHS*MOV 1A, 15A, 16A, 24A, 25A, 26A, 27A, 30A, 33A, 39A, 40A, 67A, 104, 113 / E12-F004A, F016A, F041A, F042A, F017A, F074A, F073A, F105A, F027A, F050A, F053A, F099A, F023, F008	PRIMARY CONTAINMENT ISOLATION - RHS	$B10_{T1}$,	1	N/A	N/A	YES	YES	I	DIV 1	P601	~
2RHS*MOV 1B, 1C; 15B; 16BC; 24A,B; 25B; 26B; 27B; 30B; 33B; 39B; 40B; 67B; 112 / E12-F004B,C; F016B; F041B,C; F042B,C; F017B; F074B; F073B; F105B; F027B; F050B; F053B; F099B; F009	PRIMARY CONTAINMENT ISOLATION - RHS	$B10_{T2}$,	1	N/A	N/A	YES	YES	I	DIV 2	P601	~
2SAS*HCV 160, 161	PRIMARY CONTAINMENT ISOLATION - SAS	$B10_{U1}$,	1	N/A	N/A	YES	YES	I	DIV 1	P851	~
2SAS*HCV 162, 163	PRIMARY CONTAINMENT ISOLATION - SAS	$B10_{U2}$,	1	N/A	N/A	YES	YES	I	DIV 2	P851	~
2SLS*MOV 5A / C41-F006A	PRIMARY CONTAINMENT ISOLATION - SLS	$B10_{V1}$,	1	N/A	N/A	YES	YES	I	DIV 1	P601	~
2SLS*MOV 5B / C41-F006B	PRIMARY CONTAINMENT ISOLATION - SLS	$B10_{V2}$,	1	N/A	N/A	YES	YES	I	DIV 2	P601	~
2WCS*MOV 112, 200A / G33-F004, F040	PRIMARY CONTAINMENT ISOLATION - WCS	$B10_{W1}$,	1	N/A	N/A	YES	YES	I	DIV 1	P602	~
2WCS*MOV102 / G33-F001	PRIMARY CONTAINMENT ISOLATION - WCS	$B10_{W2}$,	1	N/A	N/A	YES	YES	I	DIV 2	P602	~
	RADIOACTIVE CONCENTRATION IN PRIMARY COOLANT	C1	1	UNIT 1 H.P. LAB	(4)	(4)	(4)	II	NON-1E	~	4

TABLE A. (NRC QUESTION 421.36)

SWEC ID NUMBER / GE-NED ID NUMBER	PARAMETER DESCRIPTION	R.G. 1.97 REV 3 PARAMETER: VARIABLE	CLASSIFICATION	SENSOR: LOCATION	INSTR. RANGE	QUALIFICATION: SEISMIC	ENVIRONMENTAL	QUALITY ASSURANCE CLASSIFICATION	POWER SUPPLY	DISPLAY LOCATION NOTE 3	NOTES
	ANALYSIS OF PRIMARY COOLANT GAMMA SPECTRUM	C2	3	UNIT 1 H.D. LAB	(NA)	(NA)	(NA)	II	NON-1E	—	4
N/A / N/A	CORE TEMPERATURE	C3	1	—	—	—	—	—	—	—	6
SEE NOTE 11 / SEE NOTE 11	REACTOR COOLANT SYSTEM PRESSURE	C4	1	—	—	—	—	—	—	—	11
SEE NOTE 12	PRIMARY CONTAINMENT AREA RADIATION	C5	3	—	—	—	—	—	—	—	12
N/A / N/A	DRYWELL DRAIN SUMPS LEVEL	C6	1	—	—	—	—	—	—	—	13
2CMS*LT 11A	SUPPRESSION POOL WATER LEVEL (NARROW RNG)	C7a.	1	RX BLDG (SEC CONTMT)	197 - 202 FT	YES	YES	I	DIV 1	P601	14
2CMS*LT 11B	SUPPRESSION POOL WATER LEVEL (NARROW RNG)	C7b.	1	RX BLDG (SEC CONTMT)	197 - 202 FT	YES	YES	I	DIV 2	P898	14
2CMS*LT 9A	SUPPRESSION POOL WATER LEVEL (WIDE RNG)	C7c.	1	RX BLDG (SEC CONTMT)	192 - 217 FT	YES	YES	I	DIV 1	P601	14
2CMS*LT 9B	SUPPRESSION POOL WATER LEVEL (WIDE RNG)	C7d.	1	RX BLDG (SEC CONTMT)	192 - 217 FT	YES	YES	I	DIV 2	P898	14
SEE NOTE 15	DRYWELL PRESSURE	C8	1	—	—	—	—	—	—	—	15
SEE NOTE 16 / SEE NOTE 16	REACTOR COOLANT SYSTEM PRESSURE	C9	1	—	—	—	—	—	—	—	16

TABLE A. (NRC QUESTION 421.36)

SWEC ID NUMBER / GE-NED ID NUMBER	PARAMETER DESCRIPTION	R.G. 1.97 REV 3 PARAMETER: VARIABLE	R.G. 1.97 REV 3 PARAMETER: CLASSIFICATION	SENSOR: LOCATION	SENSOR: INSTR. RANGE	QUALIFICATION: SEISMIC	QUALIFICATION: ENVIROMENTAL	QUALITY ASSURANCE CLASSIFICATION	POWER SUPPLY	DISPLAY LOCATION NOTE 3	NOTES
SEE NOTE 17	PRIMARY CONTAINMENT PRESSURE	C10	1	—	—	—	—	—	—	—	17
2CMS*AIT 6A	CONTAINMENT HYDROGEN CONCENTRATION-A	C11a.	1	RX BLDG. NORTH AUX BAY	0-30%	YES	YES	I	DIV 1	P601	~
2CMS*AIT 6B	CONTAINMENT HYDROGEN CONCENTRATION-B	C11b.	1	RX BLDG SOUTH AUX BAY	0-30%	YES	YES	I	DIV 2	P898	~
2CMS*AIT 71A	CONTAINMENT OXYGEN CONCENTRATION-A	C12a.	1	RX BLDG NORTH AUX BAY	0-10%	YES	YES	I	DIV 1	P601	~
2CMS*AIT 71B	CONTAINMENT OXYGEN CONCENTRATION-B	C12b.	1	RX BLDG SOUTH AUX BAY	0-10%	YES	YES	I	DIV 2	P898	~
2RMS-CAB 170	CONTAINMENT EFFLUENT RADIOACTIVITY	C13	3	MAIN STACK ENCLOSURE	ISOTOPIC 10^{-7} - 10^{5} µCi/cc	NO	YES	II	NON-1E (UPS)	P882	39
2RMS-CAB 180	EFFLUENT RADIOACTIVITY	C14	2	TURB BLDG TURB OPER FLOOR	ISOTOPIC 10^{-7} - 10^{5} µCi/cc	NO	YES	II	NON-1E (UPS)	P882	39
2FWS-FT 1A,B / C33-N001A,B	MAIN FEED WATER FLOW -A,B	D1	3	TURB BLDG	0-8.5 M lbs/hr (EACH)	NO	NO	II	NON-1E	P603	~
2CNS-LT 8A,B	CONDENSATE STORAGE TK LVL -A,B	D2	3	COND STOR TK 1A, TK 1B	0-500 KGAL (EACH)	NO	NO	II	NON-1E	P851	~
2RHS*FT 64A	SUPPRESSION CHAMBER SPRAY HEADER FLOW -A	D3a.	2	RX BLDG (SEC CONTMT)	0-450 GPM	YES	YES	I	DIV 1	P601	~
2RHS*FT 64B	SUPPRESSION CHAMBER SPRAY HEADER FLOW -B	D3b.	2	RX BLDG (SEC CONTMT)	0-450 GPM	YES	YES	I	DIV 2	P601	~

TABLE A. (NRC QUESTION 421.36)

SWEC ID NUMBER / GE-NED ID NUMBER	PARAMETER DESCRIPTION	R.G. 1.97 REV 3 PARAMETER: VARIABLE	R.G. 1.97 REV 3 PARAMETER: CLASSIFICATION	SENSOR: LOCATION	SENSOR: INSTR. RANGE	QUALIFICATION: SEISMIC	QUALIFICATION: ENVIROMENTAL	QUALITY ASSURANCE CLASSIFICATION	POWER SUPPLY	DISPLAY LOCATION NOTE 3	NOTES
SEE NOTE 18	DRYWELL PRESSURE	D4	2	—	—	—	—	—	—	—	18
SEE NOTE 19	SUPPRESSION POOL WATER LEVEL (WEIR WELL)	D5	2	—	—	—	—	—	—	—	19
2CMS*TE 67A, 68A, 69A, 70A	SUPPRESSION POOL WATER TEMP-A	D6a,	2	SUPPRESSION POOL	50-250°F	YES	YES	I	DIV 1	P601	20
2CMS*TE 67B, 68B, 69B, 70B	SUPPRESSION POOL WATER TEMP-B	D6b,	2	SUPPRESSION POOL	50-250°F	YES	YES	I	DIV 2	P601 P898	20
2CMS*TE 101 THRU & INC 109	DRYWELL ATMOS TEMP-A	D7a,	2	DRYWELL	0-400°F	YES	YES	I	DIV 1	P873	20
2CMS*TE 116 THRU & INC 124	DRYWELL ATMOS TEMP-B	D7b,	2	DRYWELL	0-400°F	YES	YES	I	DIV 2	P875	20
2RHS*FT 63A	DRYWELL SPRAY HEADER FLOW-A	D8a.	2	Rx BLDG (SEC CONTMT)	0-7,950 GPM	YES	YES	I	DIV 1	P601	~
2RHS*FT 63B	DRYWELL SPRAY HEADER FLOW-B	D8b.	2	Rx BLDG (SEC CONTMT)	0-7,950 GPM	YES	YES	I	DIV 2	P601	~
SEE NOTE 19 / SEE NOTE 19	MAIN STEAM LINE ISOLATION VALVE LEAKAGE CONTROL SYSTEM PRESS	D9	2	—	—	—	—	—	—	—	19
2SVV*ZT 220 - 237	PRIMARY SAFETY RELIEF VALVE POSITION	D10a.	2	ACOUSTIC SENSOR ON TAIL PIPE (18 TOTAL)	—	YES	YES	I	DIV 1	2SVV-PNL 140	~
2IAS*PT 181	PRIMARY SAFETY RELIEF VALVE -ADS HEADER PRESSURE -A	D10b,	2	Rx BLDG (SEC CONTMT)	0-250 PSIG	YES	YES	I	DIV 1	P601	~

TABLE A (NRC QUESTION 421.36)

SWEC ID NUMBER GE-NED ID NUMBER	PARAMETER DESCRIPTION	R.G. 1.97 REV 3 PARAMETER: VARIABLE	R.G. 1.97 REV 3 PARAMETER: CLASSIFICATION	SENSOR: LOCATION	SENSOR: INSTR. RANGE	QUALIFICATION: SEISMIC	QUALIFICATION: ENVIRONMENTAL	QUALITY ASSURANCE CLASSIFICATION	POWER SUPPLY	DISPLAY LOCATION NOTE 3	NOTES
2IAS*PT230,231,232 —	PRIMARY SAFETY RELIEF VALVE -ADS TANK PRESSURE	D10c.	2	RX BLDG (SEC CONTMT)	0-200 PSIG	YES	YES	I	DIV 1	P601	—
2IAS*PT186 —	PRIMARY SAFETY RELIEF VALVE -ADS HEADER PRESSURE -B	D10d.	2	RX BLDG (SEC CONTMT)	0-250 PSIG	YES	YES	I	DIV 2	P601	—
2IAS*PT233,234,235,236 —	PRIMARY SAFETY RELIEF VALVE -ADS TANK PRESSURE	D10e.	2	RX BLDG (SEC CONTMT)	0-200 PSIG	YES	YES	I	DIV2	P601	—
SEE NOTE 19 SEE NOTE 19	ISOLATION CONDENSER - SHELL SIDE WATER LEVEL	D11	2	—	—	—	—	—	—	—	19
SEE NOTE 19 SEE NOTE 19	ISOLATION CONDENSER VALVE POSITION	D12	2	—	—	—	—	—	—	—	19
2ICS*FT102 E51-N051	RCIC FLOW	D13	2	RX BLDG (SEC CONTMT)	0-800 GPM	YES	YES	I	DIV 1	N/A	—
2CSH*FT105 E22-N056	HPCI/S FLOW	D14	2	RX BLDG (SEC CONTMT)	0-1000 GPM	YES	YES	I	DIV3	N/A	21
2CSL*FT107 E21-N051	LPCS FLOW	D15.	2	RX BLDG (SEC CONTMT)	0-10,000 GPM	YES	YES	I	DIV1	N/A	—
2RHS*FT14A E12-N015A	LPCI FLOW	D16a.	2	RX BLDG (SEC CONTMT)	0-8400 GPM	YES	YES	I	DIV1	P601	—
2RHS*FT14B,C E12-N015B,C	LPCI FLOW	D16b.	2	RX BLDG (SEC CONTMT)	0-8,400 GPM	YES	YES	I	DIV2	P601	—
2SLS*FT113 C41-N007	SLCS FLOW	D17	2	RX BLDG (SEC CONTMT)	0-86 GPM	YES	YES	I	DIV 1	P601	—

TABLE A (NRC QUESTION 421.36)

SWEC ID NUMBER / GE-NED ID NUMBER	PARAMETER DESCRIPTION	R.G. 1.97 REV 3 PARAMETER		SENSOR		QUALIFICATION		QUALITY ASSURANCE CLASSIFICATION	POWER SUPPLY	DISPLAY LOCATION NOTE 3	NOTES
		VARIABLE	CLASSIFICATION	LOCATION	INSTR. RANGE	SEISMIC	ENVIRONMENTAL				
2SLS * LT103 / C41-N001	SLCS STORAGE TANK LEVEL	D18	2	RX BLDG (SEC CONTMT)	0-10,000 GAL	YES	YES	I	DIV I	P601	~
SEE NOTE 22 / SEE NOTE 22	RHR SYSTEM FLOW	D19	2	—	—	—	—	—	—	—	22
2RHS * TE13A / E12-N027A	RHR HEAT EXCHANGER OUTLET TEMP -A	D20a,	2	RX BLDG (SEC CONTMT)	0-600°F	NO	NO	II	NON-1E	P601	~
2RHS * TE13B / E12-N027B	RHR HEAT EXCHANGER OUTLET TEMP -B	D20b,	2	RX BLDG (SEC CONTMT)	0-600°F	NO	NO	II	NON-1E	P601	~
2SWP * TE31A	COOLING WATER TEMP TO ESF SYSTEM COMPONENTS -A	D21a.	2	SCREEN WELL BLDG	35-130°F	YES	YES	I	DIV I	P601	20
2SWP * TE31B	COOLING WATER TEMP TO ESF SYSTEM COMPONENTS -B	D21b,	2	SCREEN WELL BLDG	35-130°F	YES	YES	I	DIV 2	P601	20
2SWP * FT13A / E12-N007A	COOLING WATER FLOW TO ESF SYSTEM COMPONENTS -A	D22a,	2	RX BLDG (SEC CONTMT)	0-10,000 GPM	YES	YES	I	DIV I	P601	23
2SWP * FT13B / E12-N007B	COOLING WATER FLOW TO ESF SYSTEM COMPONENTS -B	D22b,	2	RX BLDG (SEC CONTMT)	0-10,000 GPM	YES	YES	I	DIV 2	P601	23
2SWP * FT76A	COOLING WATER FLOW TO ESF SYSTEM COMPONENTS - DIV I DSL	D22c,	2	DIESEL GEN. BLDG	0-860 GPM	YES	YES	I	DIV I	P852	24
2SWP * FT76B	COOLING WATER FLOW TO ESF SYSTEM COMPONENTS - DIV 2 DSL	D22d,	2	DIESEL GEN. BLDG	0-860 GPM	YES	YES	I	DIV 2	P852	24
2SWP * FT535	COOLING WATER FLOW TO ESF SYSTEM COMPONENTS - DIV 3 DSL	D22e.	2	DIESEL GEN. BLDG	0-650 GPM	YES	YES	I	DIV 3	P852	24

TABLE A (NRC QUESTION 421.36)

SWEC ID NUMBER / GE-NED ID NUMBER	PARAMETER DESCRIPTION	R.G. 1.97 REV 3 PARAMETER VARIABLE	R.G. 1.97 REV 3 PARAMETER CLASSIFICATION	SENSOR LOCATION	SENSOR INSTR. RANGE	QUALIFICATION SEISMIC	QUALIFICATION ENVIROMENTAL	QUALITY ASSURANCE CLASSIFICATION	POWER SUPPLY	DISPLAY LOCATION NOTE 3	NOTES
2LWS-2A,B,C; 2CA,B; 276; 280	HIGH RADIOACTIVITY LIQUID TANK LEVEL	D23	3	RADWASTE BLDG	0-100%	NO	NO	II	NON-1E	LWCS COMPUTER GRAPHICS	~
2HVR*AOD1A,6A,9A,10A	EMERGENCY VENTILATION DAMPER POSITION	D24a.	2	Rx BLDG (SEC CONTMT)	N/A	YES	YES	I	DIV 1	P870	~
2HVR*AOD1B,6B,9B,10B	EMERGENCY VENTILATION DAMPER POSITION	D24b.	2	Rx BLDG (SEC CONTMT)	N/A	YES	YES	I	DIV 2	P871	~
N/R	STATUS OF STDBY PWR SOURCES - BATTERY VOLTAGE -1	D25a.	2	2BYS*SWG002A	0-150 VDC	YES	YES	I	DIV 1	P852	~
2BYS*E/E1A	STATUS OF STDBY PWR SOURCES - BATTERY CURRENT -1	D25b.	2	2BYS*SWG002A	-2000 TO +2000 AMPS	YES	YES	I	DIV 1	P852	—
N/R	STATUS OF STDBY PWR SOURCES - BATTERY VOLTAGE -2	D25c.	2	2BYS*SWG002B	0-150 VDC	YES	YES	I	DIV 2	P852	~
2BYS*E/E1B	STATUS OF STDBY PWR SOURCES - BATTERY CURRENT -2	D25d.	2	2BYS*SWG002B	-2000 TO +2000 AMPS	YES	YES	I	DIV 2	P852	~
N/R	STATUS OF STDBY PWR SOURCES - BATTERY VOLTAGE -3	D25e.	2	2EGS*PNL002	0-150 VDC	YES	YES	I	DIV 3	P852	~
2BYS*E/E101	STATUS OF STDBY PWR SOURCES - BATTERY CURRENT -3	D25f.	2	2EGS*PNL002	-100 TO +100 AMPS	YES	YES	I	DIV 3	P852	~
N/R	STATUS OF STDBY PWR SOURCES - UPS VOLTAGE -A	D25g.	2	2VBS*UPS2A	0 TO 120 VAC	YES	YES	I	DIV 1	P852	~
N/R	STATUS OF STDBY PWR SOURCES - UPS CURRENT -A	D25h.	2	2VBS*UPS2A	0 TO 250 AMPS	YES	YES	I	DIV 1	N/A	~

TABLE A (NRC QUESTION 421.86)

SWEC ID NUMBER / GE-NED ID NUMBER	PARAMETER DESCRIPTION	R.G. 1.97 REV 3 PARAMETER VARIABLE	R.G. 1.97 REV 3 PARAMETER CLASSIFICATION	SENSOR LOCATION	SENSOR INSTR. RANGE	QUALIFICATION SEISMIC	QUALIFICATION ENVIRONMENTAL	QUALITY ASSURANCE CLASSIFICATION	POWER SUPPLY	DISPLAY LOCATION NOTE 3	NOTES
N/R	STATUS OF STBY PWR SOURCES - UPS VOLTAGE -B	$D25_j$,	2	2VBS*UPS2B	0 TO 120 VAC	YES	YES	I	DIV 2	P852	~
N/R	STATUS OF STBY PWR SOURCES - UPS CURRENT -B	$D25_k$,	2	2VBS*UPS2B	0 TO 250 AMPS	YES	YES	I	DIV 2	N/A	~
N/R	STATUS OF STBY PWR SOURCES - 600V SWGR VOLTAGE	$D25_l$,	2	2EJS*RS1.	0 TO 750 VAC	YES	YES	I	DIV 1	2EJS*RS1	25
N/R	STATUS OF STBY PWR SOURCES - 600V SWGR CURRENT	$D25_m$,	2	2EJS*X1A, B	0 TO 3000 AMPS	YES	YES	I	DIV 1	N/A	26
N/R	STATUS OF STBY PWR SOURCES - 600V SWGR VOLTAGE	$D25_n$.	2	2EJS*RS3	0 TO 750 VAC	YES	YES	I	DIV 2	2EJS*RS3	25
N/R	STATUS OF STBY PWR SOURCES - 600V SWGR CURRENT	$D25_p$,	2	2EJS*X3A,B	0 TO 3000 AMPS	YES	YES	I	DIV 2	N/A	26
N/R	STATUS OF STBY PWR SOURCES - 4KV. SWGR VOLTAGE	$D25_q$.	2	SWGR	0 TO 4.16 KV	YES	YES	I	DIV 1	P852	25
N/R	STATUS OF STBY PWR SOURCES - 4KV SWGR CURRENT	$D25_r$,	2	SWGR	0-1000 AMP - DIESEL FEED 0-1,500 AMP - NORMAL & ALT FEEDS	YES	YES	I	DIV 1	P852	27
N/R	STATUS OF STBY PWR SOURCES - 4KV SWGR VOLTAGE	$D25_s$,	2	SWGR	0 TO 4.16 KV	YES	YES	I	DIV 2	P852	25
N/R	STATUS OF STBY PWR SOURCES - 4KV SWGR CURRENT	$D25_t$.	2	SWGR	0-1,000 AMP - DIESEL FEED 0-1,500 AMP - NORMAL & ALT FEEDS	YES	YES	I	DIV 2	P852	27
N/R	STATUS OF STBY PWR SOURCES - 4KV SWGR VOLTAGE	$D25_u$.	2	SWGR	0 TO 4.16 KV	YES	YES	I	DIV 3	P852	25

TABLE A (NRC QUESTION 421.36)

SWEC ID NUMBER / GE-NED ID NUMBER	PARAMETER DESCRIPTION	R.G. 1.97 REV 3 PARAMETER		SENSOR		QUALIFICATION		QUALITY ASSURANCE CLASSIFICATION	POWER SUPPLY	DISPLAY LOCATION NOTE 3	NOTES
		VARIABLE	CLASSIFICATION	LOCATION	INSTR. RANGE	SEISMIC	ENVIRONMENTAL				
NIR	STATUS OF STDBY PWR SOURCES - 4KV SWGR CURRENT	D25y.	2	SWGR	0-600 AMP - DIESEL FEED 0-1,500 AMP - NORMAL (ALT) FEEDS	YES	YES	I	DIV 3	PS52	27
SEE NOTE 28	STATUS OF STDBY PWR SOURCES - AIR FOR ADS	D25w.	2	—	—	—	—	—	—	—	28
2RMS*RE1A,C	PRIMARY CONTAINMENT AREA RADIATION HIGH RNG	$E1_a$	1	DRYWELL	$1-10^7$ R/hr	YES	YES	I	DIV 1	P880	~
2RMS*RE1B,D	PRIMARY CONTAINMENT AREA RADIATION HIGH RNG	E1b	1	DRYWELL	$1-10^7$ R/hr	YES	YES	I	DIV 2	P880	~
SEE NOTE 29	SECONDARY CONTAINMENT AREA RADIATION	E2	2	—	—	—	—	—	—	—	29
SEE NOTE 30	VITAL AREA RADIATION MONITORS	E3	3	SEE NOTE 30	SEE NOTE 30	NO	NO	II	NON-1E	RADN COMPUTER GRAPHICS	30,31
SEE NOTE 32	EFFLUENT RADIATION RELEASED FROM PLANT	E4	2	—	—	—	—	—	—	—	32
SEE NOTE 33	ENVIRONS RADIATION AND RADIOACTIVITY	E5	3	—	—	—	—	—	—	—	31,33
SEE NOTE 34	METEOROLOGY	E6	3	—	—	—	—	—	NON-1E	P882	31,34
2SSP-IPNL101 / D24-D007	ACCIDENT SAMPLING PRIMARY COOLANT & CONTAINMENT AIR	E7	3	RADWASTE SAMPLE ROOM	N/A	NO	NO	II	NON-1E	~	4,35

NOTES FOR NRC QUESTION 421.36 TABLE A

1. CONSISTS OF ALL LPRM'S CLASSIFIED AS FOLLOWS:

LPRM - GROUP A	(21 LPRM'S)
LPRM - GROUP B	(22 LPRM'S)
APRM - CHANNEL A	(21 LPRM'S)
APRM - CHANNEL B	(22 LPRM'S)
APRM - CHANNEL C	(21 LPRM'S)
APRM - CHANNEL D	(22 LPRM'S)
APRM - CHANNEL E	(21 LPRM'S)
APRM - CHANNEL F	(22 LPRM'S)

2. AVERAGE WEIGHTED VALUE SIGNAL FROM NEUTRON MONITORING CIRCUITS.

3. ALL DISPLAYS ARE AVAILABLE ON SPDS, OR RADIATION COMPUTER TERMINALS. LOCATIONS DEFINED PROVIDE ANALOG/DIGITAL INDICATION TO OPERATORS.

4. DATA MANUALLY ENTERED INTO COMPUTER

5. ZERO REFERENCE IS AT 380.69" (TOP OF CORE SUPPORT PLATE) RPV INVERT IS 0.0" REFERENCE. SEE NUREG 0737 JUSTIFICATION FOR NON-CONFORMANCE

6. PARAMETER NOT MEASURED OR MONITORED

PER BWROG POSITION THAT BWR CORE THERMOCOUPLES ARE INEFFECTIVE IN A BWR CORE BECAUSE OF THERMODYNAMIC CONSIDERATIONS (POSITION BASED UPON RG 1.97 REV 2)

7. DRYWELL SUMPS MONITORED VIA SUPPRESSION POOL LEVEL INSTRUMENTS (PARAMETER C7a,b) AFTER AN ACCIDENT

8. UPPER RANGE OF INSTRUMENT COVERED BY VARIABLE B.7.b.

9. TESTABLE CHECK VALVE, OUTBOARD OF CONTAINMENT

10. TRAVERSING IN-CORE PROBE (5 ASSBL'YS)

11. PARAMETER SAME AS PARAMETER B 6 a, b.

12 PARAMETER SAME AS PARAMETER E 1 a, b.

13. NMP-2 HAS A MARK II CONTAINMENT. DURING A LOCA, THE SUPPRESSION POOL SERVES AS A SUMP BECAUSE THE OUTSIDE (OF CONTAINMENT) HOLDING TANKS ARE ISOLATED

14. BOTTOM OF ECCS SUCTION LINE IS 192'
SUPPRESSION POOL N.W.L. IS 200'

15. PARAMETER SAME AS PARAMETER B 7 a, b.

16. PARAMETER SAME AS PARAMETER B 6 a, b.

17. PARAMETER SAME AS PARAMETERS B7a,b & B9a,b.
OVERLAPPING OF RANGES IS REQUIRED TO MEET R.G.

18. PARAMETER SAME AS PARAMETER B9a,b.

19. PARAMETER NOT APPLICABLE TO NMP-2

20. INSTRUMENT RANGE MEETS INTENT OF THE GUIDE.

21. NMP-2 UTILIZES HPCS IN LIEU OF HPCI

22. PARAMETER SAME AS PARAMETER D16a,b.

23. SERVICES RHR HEAT EXCHANGERS

24 SERVICES EMERGENCY DIESEL GENERATOR SETS. NOTE THAT FLOW IS MEASURED FROM DIESEL VS. TO DIESEL.

25. BUSS VOLTAGE IS MEASURED

26. PARAMETER CONSISTS OF TWO SIGNALS: NORMAL & ALTERNATE FEEDER CURRENT (INDIVIDUAL INPUTS)

27. PARAMETER CONSISTS OF THREE SIGNALS: NORMAL, ALTERNATE, & DIESEL FEEDER CURRENT (INDIVIDUAL INPUTS)

28. PARAMETER SAME AS PARAMETER D10 b, c, d, and e.

29. PARAMETER NOT IN COMPLIANCE WITH GUIDE. RADIATION MONITORS ARE NOT QUALIFIED TO R.G. 1.89. JUSTIFICATION: THE REACTOR BUILDING IS INACCESSABLE AFTER A LOCA.

30.

MONITOR ID	DESCRIPTION	INSTR. RNG.
2RMS-RE 118	Turb Bldg Sample Rm	$.1 - 10^4$ mR/hr
2RMS-RE 121	Radwaste Control Rm	$.01 - 10^3$ mR/hr
2RMS-RE 129	Main Control Rm	$.01 - 10^3$ mR/hr
2RMS-RE 190	Relay & Computer Rm	$.1 - 10^4$ mR/hr
2RMS-RE 191	H.P./Low Level Counting Rm	$.1 - 10^4$ mR/hr
2RMS-RE 192	Rx/Radw Vent Monitor	$.1 - 10^4$ mR/hr
2RMS-RE 193	Main Stack Release Monitor	$.1 - 10^4$ mR/hr

31. DATA NOT ENTERED INTO EMERGENCY RESPONSE FACILITIES (ERF) COMPUTER

32. PARAMETER SAME AS PARAMETERS C13, C14. Additional info: a) Particulate RadN Level: $10^{-12} - 10^{2}$ μCi/cc

b) Flow Rate 1) Main Stack : 0 - 102,000 CFM

2) Rx/Radw Vent : 0 - 237,310 CFM

c) Halogen RadN Level: $10^{-12} - 10^{2}$ μCi/cc

33. Full compliance RHP
TO R.G. 1.97 EXISTS FOR: PORTABLE SAMPLING AND MULTICHANNEL SPECTROMETER. PORTABLE INSTRUMENTATION DOES NOT COVER THE REQUIRED RANGE. THIS EQUIPMENT, HOWEVER, REPRESENTS THE "BEST AVAILABLE TECHONOLOGY."

34. FULL COMPLIANCE RHP
TO R.G. 1.97 EXISTS FOR:

a) WIND DIRECTION

b) WIND SPEED

c) ATMOSPHERIC STABILITY

35. H.P. TO PROVIDE ANALYSIS FROM LAB

36. NON-DIVISIONAL INDICATION ON P849. VALVES NORMALLY CLOSED DURING RX OPERATION.

37. a) ALL VALVES INDICATED ON P602 - 2CCP*MOV 15A,B; 16A,B; 17A,B; 94A,B

b) ALL VALVES INDICATED ON P873 - 2CCP*MOV 122, 124, 265, 273

38 a) ALL VALVES INDICATED ON P601 - 2IAS*SOV 164, 165

b) ALL VALVES INDICATED ON P851 - 2IAS*SOV 166, 167, 168, 180, 184, 185

39. INDICATION IS GROSS GAS CHANNEL, INSTRUMENT RNG: 10^1 TO 10^7 CPM.

NINE MILE POINT 2 FSAR

QUESTION

421.37 (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 conform that they are included in the listing required by Item 1 above.

RESPONSE

A methodology has been developed for addressing concerns raised in IE Bulletin 79-27. This methodology, applied on WNP2, has been reviewed and approved by the NRC. The same methodology will be used in performing the required study for the NMP2 project. The NMP2 study is currently scheduled for completion in the second quarter of 1985. The methodology provides for a systematic and comprehensive analysis to ensure that, in the event of a single power bus failure, sufficient control room indicators, instruments, and controls exist for the operators to achieve reactor cold shutdown. The following paragraphs outline the methodology to be used in addressing the concerns identified in IE Bulletin 79-27.

1) Review the Class 1E and non-Class 1E buses, including inverters, supplying power to instrumentation and controls in systems used in attaining the cold shutdown condition. All buses that could affect the ability to achieve cold shutdown are identified. Existing plant operating procedures and procedures already developed for the event of certain power bus failures are used to ensure the identification of all potential power buses.

2) Identify the instrumentation and control devices connected to each identified power bus. Evaluate the effects of a power loss to each load, including the limiting effects on the ability to achieve cold shutdown.

3) Create "bus trees" denoting the bus hierarchy and cascading bus configuration of all buses that power instrumentation and controls used by the operator to achieve cold shutdown.

4) Determine the annunciators and alarms that would alert the operators to a failure of any of the identified buses.

5) Determine the effect of any single power bus loss on the ability to continue in the particular shutdown path being used at the time the bus loss occurs. This analysis includes the cascading effects of any bus loss and considers alternative indications and controls powered by unaffected buses that may aid the operator in the event of a bus loss. Identify alternative shutdown paths available in the event of a bus loss and existing procedures for restoration of the affected bus.

6) Document the results of the analysis with recommendations of hardware or procedural changes.

QUESTION 421.42
(7.7)

The transient and accident analyses included in the FSAR are intended to demonstrate the adequacy of safety systems in mitigating anticipated operational occurrences and accidents.

Based on the conservative assumptions made in defining these "design bases" events and the detailed review of the analyses by the staff, it is likely that they adequately bound the consequences of single control system failures. To provide assurance that the design basis event analysis for Nine Mile Point 2 adequately bounds other more fundamental credible failures, provide the following:

(1) Identify those control systems whose failure of malfunction 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 whose failure or malfunction could lead to failure or malfunction of 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 common taps, hydraulic headers and impulse lines feeding pressure, temperature, level or other signals to two or more control systems.

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

RESPONSE

Two system interaction studies, common power failure analysis and common sensor failure or sensing line analysis, are required to address the issues of this question. The methodology to be applied for these analyses for NMP-2 has already been approved by the NRC for Grand Gulf, Shoreham and WNP-2 analyses. The studies will evaluate the consequences of single power source or sensing line failures on control grade systems and determine whether the limiting case events are bounded by Chapter 15 analyses. These studies are scheduled for completion second quarter of 1985.

A. Common Power Source Failure

The following paragraphs outline the methodology to be used in the common power source failure analysis.

1) Identify all non-safety control grade systems that could affect the critical reactor parameters, i.e., water level, pressure, and power.

2) Review these control systems at the component level. Identify the effect of the loss of power to each system component and subsequent interactions with other components and systems.

3) Generate "bus trees" which represent the bus hierarchy and cascading configuration of all power buses that supply components of control systems under study.

4) Perform a combined effects analysis. Evaluate the failure of each power bus, i.e., load center, motor control center, etc. starting with the lowest level source common to multiple control systems and working up the "bus trees" to the highest common power level. At each level, examine the effects of the single bus failure and consequential cascading bus failures on all control systems' components affected.

5) Postulate the limiting transient events as a result of the combined effect analysis. Compare these events to those analyzed in Chapter 15.

6) Perform any additional transient calculations or analyses required to determine whether the postulated transient events are bounded* by Chapter 15 analyses, assuming there is a single active failure in a safety system required to mitigate effects of the event.

7) Identify any hardware or procedural change recommendations that result from this study.

B. Common Sensor or Sensing Line Failure

The following paragraphs outline the methodology to be used in the common sensor or sensing line failure analysis.

1) Identify all non-safety control grade systems that could affect the critical reactor parameters, i.e., water level, pressure, and power.

2) Identify all instrument sensing lines and sensors common to two or more of these control systems.

3) Analyze the effects of a failure of a common sensors, a complete plug, or a guillotine break in each of these common instrument lines. Examine the effects of the erroneous signals on each affected instrument and on each function, i.e., scrams, trips, permissives, etc., actuated or rendered inoperative.

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4) Examine the interactive effects among all systems affected by the common sensing line failure and the consequential combined effect on the critical reactor parameters.

5) Compare the consequences of these postulated events with the Chapter 15 analyses to ensure that Chapter 15 bounds the effects and the events would not require action or responses beyond the capability of operators or safety systems. Perform any additional transient calculations or analyses necessary to determine whether the postulated limiting events are bounded* by those events analyzed in Chapter 15, assuming there is a single active failure in a safety system required to mitigate effects of the event.

6) Identify any hardware or procedural change recommendations that result from this study.

*The term "bounded" means within the consequence limits for abnormal operational transients given in Section 15.0.3.1.2 of the FSAR or, if the combined probability of occurrence of both the initiating event and the single active failure is similar to the occurrence probabilities of limiting faults (see Section 15.0.3.1), "bounded" means within the consequence limits for limiting the faults given in Section 15.0.3.1.3.

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~~LDCN GE 123~~
~~ATTACHMENT I~~
~~pg 1 of 2~~

QUESTION

421.43 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-related 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 analyses. 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.

RESPONSE

HIGH ENERGY LINE BREAK AND CONTROL
SYSTEM FAILURE EVALUATION

INTRODUCTION

IE Information Notice 79-22 identifies the concern that the performance of nonsafety grade equipment subjected to an adverse environment could impact the protective functions performed by safety grade equipment. The purpose of this analysis is to determine if a malfunction of a nonsafety control system, associated with a high energy line break, might result in a severe event not bounded by FSAR Chapter 15.

METHODOLOGY

The HELB/control system failure evaluation will be analyzed as follows:

1. Identify all nonsafety control systems and components within these systems which may impact critical reactor parameters (water level, pressure, power).

2. Establish the criteria for energy lines, break postulation, and consequence evaluation.

3. Identify critical nonsafety grade components located in areas of high energy piping..

4. Postulate breaks in these areas and determine the resultant effects on the components.

5. Evaluate the events to determine if the event is bounded by FSAR Chapter 15. If not bounded, additional analysis or a corrective action will be taken.

NONSAFETY CONTROL SYSTEMS

All plant nonsafety control systems are included in the initial evaluation for HELB. The following criteria is used for the elimination of systems from the initial list prior to performing a detailed HELB analysis.

1. Dedicated inputs into the process computer, as well as the computer itself.

2. Control systems which have no direct or indirect interaction with reactor operating parameters. Examples are communications, lighting, ventilation for exterior buildings, machine shop systems, refueling or maintenance systems, etc.

3. Control systems that do interact or interface with reactor operating systems, but which cannot affect the reactor parameters either directly or indirectly.

4. Electrical systems, the loss of which will result in a condition similar to total or partial loss of offsite power. Examples include the station transformers, ac instrument power, and dc instrument power.

5. Systems which are not used during normal power operation. For example, refueling systems, turning gear, and turbine bearing lift pumps.

6. Safety systems or safety portions of control systems.

7. Mechanical and structural type systems. Examples include structural steel, turbines, cranes, etc.

All control components, including power sources, within systems not eliminated by the above criteria are evaluated for component elimination by the following criteria prior to the final HELB analysis.

1. Instruments which provide only indication or position status information are excluded from the detailed analysis.

2. Components which provide passive inputs into the control logic, examples of which are arming-type permissives which require additional manual action to command equipment to operate, are excluded from the detailed analysis.

3. Instruments and other dedicated inputs to the process computer are excluded from the detailed analysis.

4. Position switches on air- and motor-operated valves which are not interlocked with other equipment but rather provide position indication or position status to the process computer are excluded from the detailed analysis.

5. Mechanical type components, such as structural steel, tanks, and pipes are not considered "components" which can fail. However, associated instruments, taps, tubing, and control components not eliminated by Items 1 through 4 and physically located on the above mechanical components, are evaluated.

PIPE BREAK CRITERIA

The pipe break criteria is taken directly from FSAR Section 3.6.

1. Pipe Criteria

   High energy piping is defined as including those systems or portions of systems in which the maximum operating temperature exceeds 200°F or the maximum operating pressure exceeds 275 psig during normal full power operation. Those lines that operate above these limits for only a relatively short period of time (less than 2 percent) to perform their intended function, are classified as moderate energy and excluded from consideration.

2. Break Postulation

   High energy pipes are assumed to break only at terminal ends and at each intermediate pipe fitting or weld attachment. Each longitudinal or circumferential break in high energy fluid system piping is considered separately as a single postulated initial event occurring during normal plant conditions.

3. Consequence Evaluation

   Pipe breaks are evaluated for the effects of pipe whip, jet impingement, and environmental effects.

   a. Pipe Whip

      Pipe whip is assumed to occur in the plane defined by the piping geometry and to cause movement in the direction of the jet reaction.

   b. Jet Impingement

      Jet impingement loads are determined by taking the jet force as being constant at all effective distances from, and normal to, the break area and by assuming that the jet stream diverges conically at a solid angle of 20 degrees.

ANALYSIS

1. Utilizing current plant drawings, the nonsafety control components and high energy systems will be located in particular zones.

2. In small zones it will be assumed that any HELB would incapacitate all nonsafety control components in the zone.

3. In large zones the effect of a high energy line break on each component will be evaluated based upon the pipe criteria.

4. Postulate breaks and evaluate the effects on the controls equipment.

5. Compare postulated effects with events as reported in FSAR Chapter 15 to determine if they are bounded.

6. If not bounded, determine if protection or relocation of the controls equipment is appropriate.

   may be performed

7. If required ... additional analysis to determine if the effect is significant and then a corrective action will be taken.

8. Draft final report.

QUESTION 421.44 (7.7)

A. Table 7.1-1 of the FSAR lists the safety-related instrumentation and control systems. Nonsafety-related systems are identified in Table 7.7-1. From a review of Chapter 15 of the FSAR the staff has determined that the analysis of certain anticipated operational occurrences (i.e., the feedwater controller failure-maximum demand) and design basis accidents (i.e., recirculation pump seizure) take credit for the operation of nonsafety-related instrumentation and control systems. It is the staff's position that for events classified as anticipated operational occurrences, credit can be taken for nonsafety-related systems to mitigate the event provided only high availability nonsafety-related systems are being relied upon. Therefore, identify each instrumentation and control system/component which is not classified as safety-related but assumed in the FSAR analyses to mitigate the consequences of transients. Provide a justification for the assumption of operability of this equipment based upon system design, equipment quality, and proposed technical specifications. In addition, provide a discussion on the interfaces with the safety-related portions of the Nine Mile Point-Unit 2 design.

B. It is the staff's position that no credit may be taken for nonsafety-related instrumentation and control systems/components in mitigating the consequences of design bases accidents. Therefore, identify each instrumentation and control system/component which is classified as nonsafety-related but assumed in the FSAR analyses to mitigate the consequences of accidents. Either redo the analysis assuming no credit for the operation of this equipment, or propose modifications to upgrade the equipment to safety-related status.

RESPONSE

A. The following non-safety grade systems/components may be actuated during the course of anticipated operational occurrences (transients) shown in Chapter 15:

a. Level 8 turbine trip,

b. Level 8 feedwater trip,

c. turbine bypass,

d. recirculation runback,

e. rod sequence control system,

f. rod block monitor, and

g. relief function of the safety relief valves.

None of these systems are required to mitigate the events analyzed in Chapter 15.

The assumed performance of the nonsafety grade system listed in Table 440.43-1, in response to Question 440.43-1, is based on extensive failure rate data for equipment of similar design and quality requirements. Among the nonsafety grade systems listed in Table 440.43-1, the failures of the L8 trip and turbine bypass would have the most adverse effects on ΔCPR. For the most limiting transient, a feedwater controller failure at maximum demand, the estimated increase in ΔCPR is about 0.02 for L8 trip failure and 0.11 for turbine bypass failure. Since this postulated event is 2 to 3 seconds in duration, no fuel failure is expected.

In summary, certain transient events assume the operation of specific nonsafety-grade equipment to provide a realistic transient signature; however, failures of such equipment would still yield events bounded by the safety limits of transient and limiting fault events analyzed in Chapters 6 and 15. The peak vessel pressure is bounded by the overpressure protection analysis described in Chapter 5.

See FSAR Section 7.7.1.5 and 10.4.4 for turbine bypass and Section 7.7.1.3 for L8 I&C design information.

B. FMEA's take no credit for nonsafety-related instrumentation and control system/components in mitigating the consequences of design basis accidents.

QUESTION
421.47

From its review of the Nine Mile Unit 2 FSAR, the NRC staff has been unable to conclude that the separation of Class 1E components and interconnecting circuits is acceptable. Regulatory Guide 1.75, "Physical Independence of Electrical Systems" which endorses IEEE Standard 384, "IEEE Trial-Use Standard Criteria for Separation of Class 1E Equipment and Circuits" provides guidance with regard to separation. To provide the level of detail necessary to complete our review, we request that you submit a comparison of the Nine Mile Point Unit 2 design to the criteria contained in R.G. 1.75 and IEEE 384. This comparison should focus on the instrumentation and control systems within both the Power Generation Control Complex and the balance of plant. The information provided should supplement FSAR Table 1.8-1 and FSAR Sections 7.1.2, 7.2.6 and 8.3.1 such that each regulatory position of R.G. 1.75 and each separation criterion of IEEE 384 is addressed. Alternate methods of providing separation to those contained in R.G. 1.75 and IEEE 384 should be identified and justified. Where barriers (e.g., flexible conduit, sheet metal enclosures, fire retardant tape) are used to provide separation, the details of the testing used to qualify the barriers should be provided. Where analyses have been used to justify lesser separation than that recommended in R.G. 1.75 and IEEE 384, a detailed discussion of the analyses including the assumptions, methods, supporting tests and conclusions should be provided.

RESPONSE

A comparison of the Nine Mile Point Unit 2 design to the criteria contained in R.G. 1.75 and IEEE 384 is shown in the following tables for instrumentation and control systems within the PGCC and balance of plant.

Note: Balance of plant response provided by SWEC.

IEEE 384-74 CRITERIA	REGULATORY GUIDE 1.75, REV. 1 REGULATORY POSITION	DESIGN CONFORMANCE PGCC	DESIGN CONFORMANCE BOP
DEFINITIONS			
Isolation device. A device in a circuit which prevents malfunctions in one section of a circuit from causing unacceptable influences in other sections of the circuit or other circuits.	C.1 Supplement IEEE 384 definition as follows "interrupting devices actuated only by fault current are not considered to be isolation devices within the context of this document.	Since interrupting devices (fuses and/or circuit breakers) actuated only by fault current are not considered as isolation devices a combination of two interrupting devices or an EPA in conjunction with an interrupting device is used.	Interrupting devices actuated only by fault current are not used as isolation devices for isolating non-class 1E circuits from class-1E circuits. In the case of control/instrument associated circuits, fuse/breakers actuated by fault current have been used to isolate non-class 1E and devices.
Raceway. Any channel that is designed and used expressly for supporting wires, cable, or busbars. Raceways consist primarily of, but are not restricted to, cable trays, conduits, and interlocked armor enclosing cable.	C.2 Interlocked armor enclosing cable should not be construed as a "raceway".	Interlocked armor cable is not used as a raceway.	Meets this requirement.
CRITERIA			
4.1 Required Separation. Separation shall be provided to maintain the independence of sufficient number of circuits and equipment so that the protective functions required during and following any design basis event can be accomplished. The degree of separation required varies with the potential hazards in a particular area.	No comment.	Separation is provided to maintain the independence of sufficient number of circuits and equipment required for protective function. Independence is achieved through equipment arrangement, materials, wiring practices and isolation devices and/or space or by analysis.	Meets this requirement.

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IEEE 384-74 CRITERIA	REGULATORY GUIDE 1.75, REV. 1 REGULATORY POSITION	DESIGN CONFORMANCE PGCC	DESIGN CONFORMANCE BOP
4.2 <u>Equipment and Circuits Requiring Separation</u>. Equipment and circuits requiring separation shall be determined and delineated early in the plant design and shall be identified on documents and drawings in a distinctive manner.	No comment.	Equipment and circuits requiring separation are delineated in the plant design documents and identified in a distinctive manner.	Meets this requirement.
4.3 <u>Methods of Separation</u>. The separation of circuits and equipment shall be achieved by safety class structures, distance, or barriers, or any combination thereof.	<u>C.3</u> Whenever practicable and where its use does not conflict with other safety objectives, locate redundant circuits and equipment in separate safety class structures.	The separation of circuits and equipment is achieved by locating them in separate safety class structures, distance, or barriers, or any combination thereof or by analysis.	Meets this requirement.
4.4 <u>Compatibility with Mechanical Systems</u>. The separation of Class 1E circuits and equipment shall be such that the required independence will not be compromised by the failure of mechanical systems served by the Class 1E systems. For example, Class 1E circuits shall be routed or protected such that failure of related mechanical equipment of one redundant system cannot disable Class 1E circuits or equipment essential to the operation of the other redundant system(s).	No comment.	Class 1E circuits are routed and/or protected such that failure of related mechanical equipment of one Class 1E system will not disable Class 1E circuits or equipment essential to the operation of its redundant system(s).	Meets this requirement.

IEEE 384-74 CRITERIA	REGULATORY GUIDE 1.75, REV. 1 REGULATORY POSITION	DESIGN CONFORMANCE PGCC	DESIGN CONFORMANCE BOP
4.5 Associated Circuits. Associated circuits shall comply with one of the following: (1) They shall be uniquely identified as such and shall remain with, or be separated the same as, those Class 1E circuits with which they are associated. (2) They shall be in accordance with (1) above from the Class 1E equipment to and including an isolation device. Beyond the isolation device a circuit is not subject to the requirements of this document provided it does not again become associated with a Class 1E system. (3) They shall be analyzed or tested to demonstrate that Class 1E circuits are not degraded below an acceptable level.	C.4 and C.6 Associated circuits should be subject to all requirements placed on Class 1E circuits such as cable derating, environmental qualification, flame retardance, splicing restrictions and raceway fill unless it can be demonstrated that the absence of such requirements could not significantly reduce the availability of the Class 1E circuits. Analysis should be submitted as part of Safety Analysis Report, and should identify those circuits installed in accordance with this section.	Associated circuits are either subject to all requirements placed on Class 1E circuits or are analyzed to demonstrate that the associated circuits will not degrade the Class 1E circuits below an acceptable level. Such an analysis, when performed, is maintained as part of the design record. ~~See note 5.~~ a summary of these analyses will be provided under seperate cover	Associated circuits are treated as class 1E circuits.
4.6 NON-CLASS 1E CIRCUITS			
4.6.1 Separation from Class 1E Circuits. Non-Class 1E circuits shall be separated from Class 1E circuits by the minimum separation requirements specified in Sections 5.1.3, 5.1.4, or 5.6 or they become associated circuits.	No comment.	Non-Class 1E circuits comply with the requirements of IEEE 384 Section 5.1.3, 5.1.4 or 5.6, or they are treated as associated circuits.	Meets this requirement except in the case of non-class 1E conduits proximate to class 1E trays. The minimum distance between a non-class 1E conduit and a class 1E cable tray (open) shall be 1 inch. See FSAR Section 1.8 RG 1.75 position for justification.

IEEE 384-74 CRITERIA	REGULATORY GUIDE 1.75, REV. 1 REGULATORY POSITION	DESIGN CONFORMANCE PGCC	DESIGN CONFORMANCE BOP
4.6.2 Separation from Associated Circuits. Non-Class 1E circuits shall be separated from associated circuits by the minimum separation requirements specified in Sections 5.1.3, 5.1.4, or 5.6.2 or (1) the effects of lesser separation between the Non-Class 1E circuits and the associated circuits shall be analyzed to demonstrate that Class 1E circuits are not degraded below an acceptable level or (2) they become associated circuits. Non-Class 1E instrumentation and control circuits are not required to be separated from associated circuits. Figure 1 shows examples of acceptable circuit arrangements.	C.6 Analysis performed in accordance with this section should be submitted as part of Safety Analysis Report and should identify those circuits installed in accordance with this section. C.7 Non-Class 1E instrumentation and control circuits should not be exempted from the provisions of Section 4.6.2.	Non-Class 1E circuits are separated from Class 1E and associated circuits in accordance with the requirements of IEEE-384, Sections 5.1.3, 5.1.4, or 5.6.2 or effects of lesser separation are analyzed to demonstrate that Class 1E circuits are not degraded below an acceptable level. Such analysis, when performed, is a part of the design record. Non-Class 1E instrumentation and control circuits are not exempted from the provisions of Section 4.6.2.	Meets this requirement.
5. SPECIFIC SEPARATION CRITERIA			
5.1 Cables and Raceways 5.1.1 General 5.1.1.1 The routing of Class 1E circuits and location of equipment served by these Class 1E circuits shall be reviewed for exposure to potential hazards such as high pressure piping, missiles, flammable material flooding, and wiring that is not flame retardant. A degree of separation commensurate with the damage potential of the hazard shall be provided such that the independence of redundant Class 1E systems are	C.8 Section 5.1.1.1 should not be construed to imply that adequate separation of redundant circuits can be achieved within a confined space such as a cable tunnel that is effectively unventilated.	Separation of Class 1E circuits and equipment makes effective use of such features as different safety structures and separated areas for redundant circuits and equipment. A degree of separation commensurate with the damage potential of the hazard is provided such that the independence of the redundant Class 1E systems is maintained at an acceptable level.	Generally, different ~~color~~ DIVISIONAL equipment are located in different rooms; different ~~color~~ cables are routed through different areas; separate tunnels are used for routing cables of different ~~colors.~~ DIVISIONS

IEEE 384-74 CRITERIA	REGULATORY GUIDE 1.75, REV. 1 REGULATORY POSITION	DESIGN CONFORMANCE PGCC	DESIGN CONFORMANCE BOP
maintained at an acceptable level. The separation of Class 1E circuits and equipment shall make effective use of features inherent in the plant design such as using different rooms or opposite sides of rooms or areas.		(See also FSAR Section 8.3.1.4.2 for exception.)	(See FSAR Section 8.3.1.4.2 for details.)
5.1.1.2 In those areas where the damage potential is limited to failures or faults internal to the electrical equipment or circuits, the minimum separation distance can be established by analysis of the proposed cable installation. This analysis shall be based on tests performed to determine the flame retardant characteristics of the proposed cable installation considering features such as cable insulation and jacket materials, cable tray fill, and cable tray arrangement.	C.6 Analysis performed in accordance with this section should be submitted as part of the Safety Analysis Report, and should identify circuits installed in accordance with these section.	Cable installations within PGCC have been analyzed for separation adequacy.	Analysis has been used in the case noted in Section 4.6.1. The analysis is included in Section 1.8, RG 1.75 position.
5.1.1.3 The minimum separation distances specified in Sections 5.1.3 and 5.1.4 are based on open ventiliated cable trays of either the ladder or trough type as defined in NEMA VE 1-1971, Cable Tray Systems. Where these distances are used to provide adequate physical separation: (1) Cables and raceways involved shall be flame retardant (2) The design basis shall be that the cable trays will not be filled above the side rails	C.9 This section should be supplemented with Item 5.1.1.3(4) as follows: "Cable splices in raceways should be prohibited". NOTE: Cable splices are not, by themselves, unacceptable. If they exist, the resulting design should be justified by analysis. The analysis should be submitted as part of the Safety Analysis Report.	Open ventilated cable trays and cable splices are not used.	Meets the criteria 1, 2 and 3 of Section 5.1.1.3 where the minimum separation distances of Sections 5.1.3 and 5.1.4 are used; cables splices in raceways are prohibited; splicing in electrical penetrations is considered to be exempt from this requirement.

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IEEE 384-74 CRITERIA	REGULATORY GUIDE 1.75, REV. 1 REGULATORY POSITION	DESIGN CONFORMANCE PGCC	DESIGN CONFORMANCE BOP
(3) Hazards shall be limited to failures or faults internal to the electric equipment or cables. If less separation distances are used they shall be established as in Section 5.1.1.2.			
5.1.2 Identification. Exposed Class 1E raceways shall be marked in a distinct permanent manner at intervals not to exceed 15 ft and at points of entry to and exiting from enclosed areas. Class 1E raceways shall be marked prior to the installation of their cables. Cables installed in these raceways shall be marked in a manner of sufficient durability and at a sufficient number of points to facilitate initial verification that the installation is in conformance with the separation criteria. These cable markings shall be applied prior to or during installation. Class 1E cables shall be identified by a permanent marker at each end in accordance with the design drawings or cable schedule. The method of identification used to meet the above requirements shall readily distinguish between redundant Class 1E systems and between Class 1E and non-Class 1E systems.	C.10 The phrase "at a sufficient number of points" should be understood to mean at intervals not to exceed 5 ft throughout the entire cable length. Also the preferred method of marking cable is color coding. C.11 This section should be supplemented as follows: "The method of identification used should be simple and should preclude the need to consult any reference material to distinguish between Class 1E and Non-Class 1E circuits, between Non-Class 1E circuits associated with different redundant Class 1E systems, and between redundant Class 1E systems.	Meets the requirement.	Meets the requirements except that the cables are marked at intervals of 15 ft. instead of 5 ft.; see FSAR Section 1.8, RG 1.75 position for the explanations. See FSAR Sec. 8.3.1.3 for the details of the methods of identification used.

IEEE 384-74 CRITERIA	REGULATORY GUIDE 1.75, REV. 1 REGULATORY POSITION	DESIGN CONFORMANCE PGCC	DESIGN CONFORMANCE BOP
5.1.3 Cable Spreading Area The cable spreading area is the space(s) adjacent to the main control room where instrumentation and control cables converge prior to entering the control, termination, or instrument panels. The cable spreading area shall not contain high energy equipment such as switch-gear, transformers, rotating equipment, or potential sources of missiles or pipe whip and shall not be used for storing flammable materials. Circuits in the cable spreading area should be limited to control and instrumentation functions and those power supply circuits and facilities serving the control room and instrument systems. Power supply feeders to instrument and control room distribution panels shall be installed in enclosed raceways that qualify as barriers. Other power circuits that are required to traverse this area shall be assigned to a minimum number of routes consistent with their separation requirements and allocated solely for these power circuits. Such traversing power circuits shall be separated from other circuits in this area by a minimum distance of 3 ft. and barriers.	C.12 Pending issuance of other acceptance criteria, those portions of Section 5.1.3 (exclusive of the NOTE following the second paragraph) that permit the routing of power cables through the cable spreading area(s) and by implication, the control room, should not be construed as acceptable. Also, Section 5.1.3 should be supplemented as follows: "Where feasible, redundant cable spreading areas should be utilized."	Cables feeding power to control and instrumentation circuits are not required to run in conduit within PGCC. These cables are treated as control and instrumentation cables and are run in PGCC ducts along with other cables in the same division.	Meets the requirements; separate cable riser areas are used for the redundant circuits. Power cables in the riser areas are routed in enclosed raceways. See FSAR Sec. 8.3.1.4.2.

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IEEE 384-74 CRITERIA	REGULATORY GUIDE 1.75, REV. 1 REGULATORY POSITION	DESIGN CONFORMANCE PGCC	DESIGN CONFORMANCE BOP
NOTE: An acceptable alternative routing for such traversing power circuits would be to route them in imbedded conduit or in a separate enclosure designed as safety class structure (for example, a concrete duct bank or other suitable enclosure) which in effect removes them from the area defined as the cable spreading area.			
The minimum separation distance between redundant Class 1E cable trays shall be determined by Section 5.1.1.2 or, where the conditions of Section 5.1.1.3 are met, shall be 1 ft. between trays separated horizontally and 3 ft. between trays separated vertically.			
NOTE: Horizontal separation is measured from the side rail of one tray to the side rail of the adjacent tray. Vertical separation is measured from the bottom of the top tray to the top of the side rail of the bottom tray. (See also Section 5.1.4).			
Where termination arrangements preclude maintaining the minimum separation distance, the redundant circuits shall be run in enclosed raceways that qualify as barriers or other barriers shall be provided between redundant circuits. The minimum distance between these	C.13 No significance should be attached to the different tray widths illustrated in Figure 2.	See notes 2, 3, 4, 6, 7, 9 and 10.	Where the minimum separation requirements cannot be met, Sil-temp tape may be used as a separation barrier.

IEEE 384-74 CRITERIA	REGULATORY GUIDE 1.75, REV. 1 REGULATORY POSITION	DESIGN CONFORMANCE PGCC	DESIGN CONFORMANCE BOP
redundant enclosed raceways and between barriers and raceways shall be in 1 in. Figs. 2, 3, 4 and 5 illustrate examples of acceptable arrangements of barriers and enclosed raceways where the minimum separation distance cannot be maintained.			
5.1.4 General Plant Areas. In plant areas from which potential hazards such as missiles, external fires, and pipe whip are excluded, the minimum separation distance between redundant cable trays shall be determined by Section 5.1.1.2 or, where the conditions of Section 5.1.1.3 are met, shall be 3 ft. between trays separated horizontally and 5 ft. between trays separated verticially. If, in addition, high energy electric equipment such as switchgear, transformers, and rotating equipment is excluded and power cables are installed in enclosed raceways that qualify as barriers, or there are no power cables, the minimum separation distance may be as specified in Section 5.1.3.		Not applicable.	Meets the requirements.
Where plant arrangements preclude maintaining the minimum separation distance, the redundant circuits shall be run in enclosed raceways that qualify as barriers or other barriers shall be provided between redundant circuits. The minimum distance between these			

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IEEE 384-74 CRITERIA	REGULATORY GUIDE 1.75, REV. 1 REGULATORY POSITION	DESIGN CONFORMANCE PGCC	DESIGN CONFORMANCE BOP
redundant enclosed raceways and between barriers and raceways shall be in 1 in. Figs. 2, 3, 4 and 5 illustrate examples of acceptable arrangements of barriers and enclosed raceways where the minimum separation distance cannot be maintained.			
5.2 STANDBY POWER SUPPLY			
5.2.1 Standby Generating Units. Redundant Class 1E standby generating units shall be placed in separate safety class structures.	C.14 Section 5.2.1 should be supplemented as follows: And should have independent air supplies."	Not Applicable	Meets this requirement. See Section 8.3.1.1.2.
5.2.2 Auxiliaries and Local Controls. The auxiliaries and local controls for redundant standby generating units shall be located in the same safety class structure as the unit they serve or be physically separated in accordance with the requirements of Section 4.			Meets this requirement. See Section 8.3.1.1.2.
5.3 DC SYSTEM			
5.3.1 Batteries. Redundant Class 1E batteries shall be placed in separate safety class structures.	C.15 Where ventilation is required, the separate safety class structures required by Section 5.3.1 should be served by independent ventilation systems.	Not Applicable	Meets this requirement. See Section 8.3.1.4.2.
5.3.2 Battery Chargers. Battery chargers for redundant Class 1E batteries shall be physically separated in accordance with the requirements of Section 4.	No comment	Not Applicable	Meets this requirement. See Section 8.3.1.4.2.

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IEEE 384-74 CRITERIA	REGULATORY GUIDE 1.75, REV. 1. REGULATORY POSITION	DESIGN CONFORMANCE PGCC	BOP
5.4 DISTRIBUTION SYSTEM			Section 8.3.1.4.2.
5.4.1 Switchgear. Redundant Class 1E distribution switchgrear groups shall be physically separated in accordance with the requirements of Section 4.			Meets this requirement. See Section 8.3.1.4.2.
5.4.2 Motor Control Centers. Redundant Class 1E motor control centers shall be physically separated in accordance with the requirements of Section 4.			Meets this requirement. See Section 8.3.1.4.2.
5.4.3 Distribution Panels. Redundant Class 1E distribution panels shall be physically separated in accordance with the requirements of Section 4.			Meets this requirement. See Section 8.3.1.4.2.
5.5 CONTAINMENT ELECTRICAL PENETRATIONS. Redundant Class 1E containment electrical penetrations shall be physically separated in accordance with the requirements of Section 4. Compliance with Section 4 will generally require that redundant penetrations be widely dispersed around the circumference of the containment. The minimum physical separation for redundant penetrations shall meet the requirements for cables and raceways given in Section 5.1.4.	No comment	Not Applicable	Meets this requirement. See Section 8.3.1.4.2.

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IEEE 384-74 CRITERIA	REGULATORY GUIDE 1.75, REV. 1 REGULATORY POSITION	DESIGN CONFORMANCE PGCC	DESIGN CONFORMANCE BOP
Non-Class 1E circuits routed in penetrations containing Class 1E circuits shall be treated as associated circuits in accordance with the requirements of Section 4.5.			

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IEEE 384-74 CRITERIA	REGULATORY GUIDE 1.75 REV. 1 REGULATORY POSITION	DESIGN CONFORMANCE PGCC	DESIGN CONFORMANCE BOP
5.6 Control Switchboards 5.6.1 Location and Arrangement. Main control switchboards shall be located in a control room within a safety class structure. The control room shall protect from and shall not contain high energy switchgear, transformers, rotating equipment, or potential sources of missiles or pipe whip.	• No comment	• See BOP	• Meets the requirements. The main control switchboards (PGCC) are located in the control building which is a seismic Cat. I structure. The main control room does not contain any high energy equipment. See Section 3.8.
Local control switchboards shall be located so that hazards such as fires, missiles, vibration, pipe whip, and water sprays shall not cause failures common to redundant Class 1E functions.		• Not applicable.	• Meets this requirement.
Separation of redundant Class 1E equipment and circuits may be achieved by locating them on separate control switchboards physically separated in accordance with the requirements of Section 4. Where operational considerations dictate that redundant Class 1E equipment be located on a single control switchboard the requirements of Sections 5.6.2, 5.6.3, 5.6.4, and 5.6.6 shall apply.		• Controls for redundant Class 1E equipment are located on separate control panels. However, due to operational considerations, some of the redundant Class 1E controls are located on the same control panel. These items are provided with adequate separation to meet the single failure criteria.	• Meets this requirement.

IEEE 384-74 CRITERIA	REGULATORY GUIDE 1.75 REV. 1 REGULATORY POSITION	DESIGN CONFORMANCE PGCC	DESIGN CONFORMANCE BOP
5.6.2 Internal Separation. The minimum separation distance between redundant Class 1E equipment and wiring internal to the control switchboards can be established by analysis of the proposed installation. This analysis shall be based on tests performed to determine the flame retardant characteristics of the wiring, wiring materials, equipment, and other materials internal to the control switchboard. Where the control switchboard materials are flame retardant and analysis is not performed, the minimum separation distance shall be 6in. In the event the above separation distances are not maintained, barriers shall be installed between redundant Class 1E equipment and wiring.	• No comment.	• The minimum separation distance between redundant Class 1E equipment and wiring inside the control panels is maintained at 6". Due to the circuit configuration, if 6" is not achievable, alternate means are used to justify lesser degree of separation, such as metallic barriers, enclosures, conduits, isolation devices and/or analysis. See notes 2, 3, 4, 5, 7, 9, and 10.	• Meets this requirement.
5.6.3 Internal Wiring Identification. Class 1E wire bundles or cables internal to the control boards shall be identified in a distinct permanent manner at a sufficient number of points to readily distinguish between redundant Class 1E wiring and between Class 1E and non-Class 1E wiring.	• No comment.	• Class 1E wires and cables internal to panel are identified to distinguish between redundant Class 1E and non-Class 1E wiring. See notes 5 and and 8.	• Meets this requirement.
5.6.4 Common Terminations. Where redundant Class 1E wiring is terminated on common device, the provisions of Section 5.6.2 shall be met.	• No comment.	• Common terminations within the control panels meet the provisions of IEEE-384 para 5.6.2. See note 1.	• Meets this requirement.

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IEEE 384-74 CRITERIA	REGULATORY GUIDE 1.75 REV. 1 REGULATORY POSITION	DESIGN CONFORMANCE PGCC	DESIGN CONFORMANCE BOP
5.6.5 Non-Class 1E Wiring. Non-Class 1E wiring not separated from Class 1E wiring by the minimum separation distance (determined in Section 5.6.2) or by a barrier shall be treated as associated circuits in accordance with the requirements of Section 4.5.	• No comment.	• Non-Class 1E wiring within the control panels is separated from the redundant Class 1E wiring. Wherever the non-Class 1E wiring cannot be separated from the Class 1E wiring, (1) it is treated as associated wiring, or (2) an analysis is performed to demonstrate the adequacy of lesser separation, or (3) proper isolation (barrier or common device) is provided to achieve the required separation.	• Meets this requirement.
5.6.6. Cable Entrance. Redundant Class 1E cables entering the control board enclosure shall meet the requirement of Section 5.1.3.	• No comment.	• Redundant Class 1E cables entering the control board enclosure are (a) separated by a minimum distance of six inches or a barrier or (b) enclosed in a raceway. See notes 2 and 9.	• Meets this requirement
5.7 Instrumentation Cabinets. Redundant Class 1E instruments shall be located in separate cabinets or compartments of a cabinet. Where redundant Class 1E instruments are located in separate compartments of a single cabinet, attention must be given to routing of external cables to the instruments to assure that cable separation is retained.	C.16 The first paragraph of Section 5.7 should be augmented as follows: "The separation requirements of 5.6 apply to instrumentation cabinets."	• Redundant Class 1E instruments are located in separate cabinets or separate compartments of a cabinet. If redundant instruments are required to be located on a single cabinet or single single compartment, barriers are provided. Cables entering such cabinets are separated by a minimum distance; or, barriers are provided between redundant components and wiring.	• Meets this requirement.
In locating Class 1E instrument cabinets, attention must be given to the effects of all pertinent design basis events.		• See BOP response.	• Meets this requirement.

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SEPARATION EVALUATION
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IEEE 384-74 CRITERIA	REGULATORY GUIDE 1.75 REV. 1 REGULATORY POSITION	DESIGN CONFORMANCE PGCC	DESIGN CONFORMANCE BOP
5.8 <u>Sensors and Sensor to Process Connections.</u> Redundant Class IE sensors and their connections to the process system shall be sufficiently separated that functional capability of the protection system will be maintained despite any single design basis event or result therefrom. Consideration shall be given to secondary effects of design basis events such as pipe whip, steam release, radiation, missiles, or flooding. Large components such as the reactor vessel can be considered a suitable barrier if the sensor to process connecting lines are brought out at widely divergent points and routed so as to keep component between redundant lines. Redundant pressure taps located on opposite sides of a large pipe may be considered to be separated by the pipe, but the lines leaving the taps must be protected against damage from a credible common cause unless other redundant or diverse instrumentation is provided.	• No comment.	• Sufficient number of redundant sensors are provided to perform system level safety function. Adequate separation is maintained between required number of redundant sensors to maintain the functional capability of the protection system. Neutron monitoring sensor cables under the vessel are exempt from this criterion because of the space limitations.	• Meets this requirement.

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IEEE 384-74 CRITERIA	REGULATORY GUIDE 1.75 REV. 1 REGULATORY POSITION	DESIGN CONFORMANCE PGCC	DESIGN CONFORMANCE BOP
5.9 Actuated Equipment. Locations of Class 1E actuated equipment, such as pump drive motors and valve operating motors are normally dictated by the location of the driven equipment. The resultant locations of this equipment must be reviewed to ensure that separation of redundant Class 1E actuated equipment is acceptable.	• No comment.	• Redundant Class 1E actuated equipments are separated to meet the single failure criteria and assure sufficient safety function to mitigate a DBE.	• Meets this requirement.

Non-Class 1E circuits not separated by 6 inches from Class 1E or associated circuits have been analyzed to demonstrate the adequacy of lesser separation. The items analyzed are:

1. Common devices such as relays and contactors for Class 1E/Class 1E and Class 1E/non-Class 1E interfaces. Test reports and analyses are available in GE Design Record Files. Common devices include scram contactors, HFA relays, Agastat relays, and reactor mode switches.
2. Sil-Temp tape as a separation barrier. The test report and analysis is available in GE DRFs.
3. Use of flexible or rigid conduit or steel enclosures as a separation barrier. The test report and analysis is available in GE DRFs.
4. Justification of separation less than six inches between smoke detector, its wiring and Class 1E wiring is available in GE DRFs.

   Common devices are also covered under the response to Question 421.13. Sil-Temp tape and flexible conduit are covered under the response to Question 430.23.
5. NMS panels P606, P608 and P633 are exceptions to RG 1.75.
6. Justification of running bare cable along with a conduit is available in GE DRF's.
7. Justification of separation of less than 1" between redundant enclosed raceways and between barriers and raceways are available in GE DRF's.
8. Pre-wired vendor equipment that does not meet color coding is identified in GE specification.
9. Use of cable connector housing as an acceptable separation barrier is available in GE DRF's.

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10. Justification of separation of less than six inches between utility devices and its wiring and Class 1E wiring is available in GE DRF's.

11. All analyses/justification for any exceptions are documented in GE DRF's and are available on request.

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