Examination Outline Cross-Reference	**Level**	RO
300000 (SF8 IA) Instrument Air Knowledge of (INSTRUMENT AIR SYSTEM) design feature(s) and or interlocks which provide for the following: K4.02 Cross-over to other air systems	**Tier#**	2
	Group#	1
	K/A #	300000 K4.02
	Rating	3.0
	Revision	
Revision Statement:		

Question 1

Instrument Air header pressure is 55 psig, rising slowly.

Which one of the following is the LOWEST Instrument Air header pressure at which SA-PCV-609 [Service Air System Isolation] can be opened by depressing CONTROL VALVE PCV-609 RESET button on Panel A?

A. 75 psig

B. 79 psig

C. 83 psig

D. 87 psig

Answer: B
Explanation: The three Plant Air compressors take suction from the surrounding Control Building atmosphere and discharge, to a pair of cross- connected air receivers. Service Air distribution headers are supplied from the air receivers through a pressure control valve (SA-PCV-609). The pressure control valve will automatically isolate the non-essential Service Air system on low air pressure at 77 psig decreasing. SA-PCV-609 isolates the Service Air distribution header from the air compressors and receivers on low system pressure. Automatic isolation of the Service Air header, along with the storage capacity of the air receivers, ensures that the Instrument Air header will be available for a safe shutdown and cool down of the reactor. PCV-609 is an air-to-open and spring-to-close isolation valve. When air pressure on the discharge header of the air receivers drops to below 77 psig, the solenoid pilot valve de-energizes. When de-energized, the pilot valve isolates the air supply to PCV-609 and vents off its operator, thus allowing spring pressure to close PCV-609. The pilot valve will remain in the tripped position until air pressure goes above 77 psig and it is manually reset by SA-PCV-609, Control Valve PCV-609 Reset pushbutton on Panel A in the Control

Room. The pressure switch which de-energizes the solenoid also actuates a Control Room alarm. A control room annunciator is also generated when this setpoint is exceeded.

Distracters:
Answer A is plausible because the signal that closes SA-PCV-609 also generates a control room annunciator, and another control room annunciator, A-4/G-4 [Intake Bldg Control Air Low Pressure] alarms at 60 psig when IA pressure is lowering. The examinee who confuses the alarm setpoints and their relation to SA-PCV-609 may choose this answer. It is wrong because SA-PCV-609 cannot be opened until IA pressure is above 77 psig.

Answer C is plausible because the signal that closes SA-PCV-609 also generates a control room annunciator, and another control room annunciator, A-4/A-4 [Air Receiver A or B Low Pressure] alarms at 80 psig when IA pressure is lowering. The examinee who confuses the alarm setpoints and their relation to SA-PCV-609 may choose this answer. It is wrong because SA-PCV-609 could have already been opened at a lower pressure listed, 79 psig.

Answer D is plausible because the signal that closes SA-PCV-609 also generates a control room annunciator, and another control room annunciator, A-4/B-5 [Service Air Low Pressure] alarms at 85 psig when IA pressure is lowering. The examinee who confuses the alarm setpoints and their relation to SA-PCV-609 may choose this answer. It is wrong because SA-PCV-609 could have already been opened at a lower pressure listed, 79 psig.

Technical References: Lesson plan COR001-17-01 [Ops Plant Air](Rev 34), alarm card A-4/B-4 [Service Air Isolation PCV-609](Rev 44), alarm card A-4/G-4 [Intake Bldg Control Air Low Pressure](Rev 44), alarm card A-4/A-4 [Air Receiver A or B Low Pressure](Rev 44), alarm card A-4/B-5 [Service Air Low Pressure](Rev 44)

References to be provided to applicants during exam: none

Learning Objective: COR001-17-01 Obj LO-6c, Describe the operation of the interlocks associated with the following components in the Plant Air system: Plant Air Pressure Control Valve (PCV-609)

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(4)	
Level of Difficulty:	3	

SRO Only Justification:	N/A
PSA Applicability:	
N/A	

Lesson Number: COR001-17-01	Revision: 34

receiver is connected with the other through normally open cross connects.

The air receivers are sized to be able to supply at least 10 minutes of operating air to the essential instruments and controls on the loss of all air compressors.

3. Each receiver is equipped with an automatic drain trap. The trap drains any moisture accumulated in the receiver to the Turbine Building equipment drains. Over-pressure protection is provided by three 3" relief valves mounted on the receiver, set to relieve at 125 psig.

4. The air receivers discharge, via individual headers, to the air dryers to supply Instrument Air and to the Pressure Control valve (PCV-609) to supply Service Air.

Fig 2 F. Pressure Control Valve (PCV-609)

LO-01g, LO-05d, 06d SO-02e

1. This pressure control valve isolates the Service Air distribution header from the air compressors and receivers on low system pressure. Automatic isolation of the Service Air header, along with the storage capacity of the air receivers, ensures that the Instrument Air header will be available for a safe shutdown and cool down of the reactor.

2. PCV-609 is an air-to-open and spring-to-close isolation valve. The air is supplied to the valve by a solenoid operated, pilot valve (PCV-SV-609). PCV-609 is powered from 120 VAC panel CCP1A.

LO-01g, LO-05d, 06d SO-02e

When air pressure on the discharge header of the air receivers drops to below 77 psig, the solenoid pilot valve de-energizes. When de-energized, the pilot valve isolates the air supply to PCV-609 and vents off its operator, thus allowing spring pressure to close PCV-609. The pilot valve will remain in the tripped position until air pressure goes above 77 psig and it is manually reset by a pushbutton on Panel A in the Control Room. The pressure switch which de-energizes the solenoid also actuates a Control Room alarm.

LO-03e, SO-09c

3. An alarm in the Control Room is sounded when system pressure drops below 77 psig.

Lesson Number: COR001-17-01	Revision: 34

Fig 2 G. Service Air Distribution Header

LO-01h, LO-03a, SO-02f

1. The Service Air distribution header supplies compressed air at 90 to 110 psig for plant service connections (Green band 95-110psig) (hose connections), and for system service connections, such as resin transfer operations, Standby Liquid Control sparging, etc.

2. The distribution header, downstream of PCV-609 splits to provide one supply line to each of the Reactor, Turbine and Radwaste Buildings.

Table 1

An alarm is sounded in the Control Room when header pressure downstream of PCV-609 drops below 85 psig.

Fig 5 H. Air Dryers

LO-01i LO-05c, SO-02g

1. The air dryers remove water vapor from the compressed air distributed to the Instrument Air header at 95-105 psig with a dew point of < -40°F per the USAR. However, actual plant operation demonstrates that < -60°F can be achieved and maintained by the air dryers.

LO-01i LO-05c, SO-02g

1. Two sets of air dryers are used, each with an inlet and outlet filter. The inlet filters remove excess moisture and particulate from the air. The outlet filters also ensure that any desiccant released from the dryers does not enter the remainder of the system. The filters have a capacity of greater than 800 SCFM at 115 psig and 110°F.

2. The air dryer consists of two chambers, each rated to pass 1000 SCFM of air at 100 psig, that contain a desiccant material which removes water vapor from the air flow. The air is dried such that its dew point (the temperature at which moisture starts to condense) is reduced to -60°F at 100 psig. Since each set is capable of passing > 100% flow of a compressor, one set will be in service and the other will be isolated.

3. Modes of Operation for the Air Dryers

   The Instrument Air dryers can operate in one of four modes: Standby, Manual Stepping Heated, Automatic Heated and Automatic Heatless.

   a. In the Standby mode, both towers are pressurized with air flow

A-4/B-4

SETPOINT
(3402)
1. SERVICE AIR ISOLATION SIGNAL TO PCV-609 at 77 psig

CIC
SA-REL-PS609X
1. SA-PS-609

PROBABLE CAUSES
- Service air header line break.
- SAC malfunction.

REFERENCES
- Emergency Procedure 5.2AIR, Loss of Instrument Air.

SERVICE AIR ISOLATION PCV-609	PANEL/WINDOW: A-4/B-4

1. AUTOMATIC ACTIONS

   1.1 Closes SA-AO-PCV609, SERVICE AIR SUPPLY HEADER.

2. OPERATOR OBSERVATION AND ACTION

   2.1 Make gaitronics announcement twice, "All personnel using breathing equipment supplied by plant air shall move to an area with a clean atmosphere".

   2.2 Verify SA-AO-PCV609 closed.

   2.3 Check SACs operating properly.

   2.4 Enter Procedure 5.2AIR.

   2.5 WHEN pressure on IA-PI-606, INSTRUMENT AIR PRESSURE, > 77 psig, THEN as directed by SM/CRS, press SA-PCV-609, CONTROL VALVE PCV-609 RESET (C-932), button.

SETPOINT
(3410) INTAKE BLDG CONTROL AIR PRESSURE LOW at 70 psig

CIC
IA-PS-810

A-4/G-4

PROBABLE CAUSES
- SAC failure.

REFERENCES
- Emergency Procedure 5.2AIR, Loss of Instrument Air.

INTAKE BLDG
CONTROL AIR
LOW PRESSURE

PANEL/WINDOW:
A-4/G-4

1. OPERATOR OBSERVATION AND ACTION

1.1 IF instrument air pressure lowering, THEN concurrently enter Procedure 5.2AIR.

1.2 Control seal water to circulating water pumps and screen wash pumps locally.

SETPOINT
(3412) SERVICE AIR PRESSURE LOW at 85 psig

CIC
SA-PS-810

A-4/B-5

PROBABLE CAUSES
- Service air header line break.
- SACs malfunction.

REFERENCES
- Emergency Procedure 5.2AIR, Loss of Instrument Air.

SERVICE AIR
LOW PRESSURE

PANEL/WINDOW:
A-4/B-5

1. OPERATOR OBSERVATION AND ACTION

NOTE – Service Air System isolation occurs at 77 psig from SA-PS-609.

1.1 Make gaitronics announcement twice, "All personnel using breathing equipment supplied by plant air shall move to an area with a clean atmosphere".

1.2 Verify SACs operating properly.

1.3 Enter Procedure 5.2AIR.

A-4/A-4

SETPOINT	CIC
1. (3400) AIR RECEIVER A PRESSURE LOW at 80 psig	1. SA-PS-603A
2. (3401) AIR RECEIVER B PRESSURE LOW at 80 psig	2. SA-PS-603B

PROBABLE CAUSES

- Line break.

REFERENCES

- Emergency Procedure 5.2AIR, Loss of Instrument Air.

AIR RECEIVER
A OR B
LOW PRESSURE

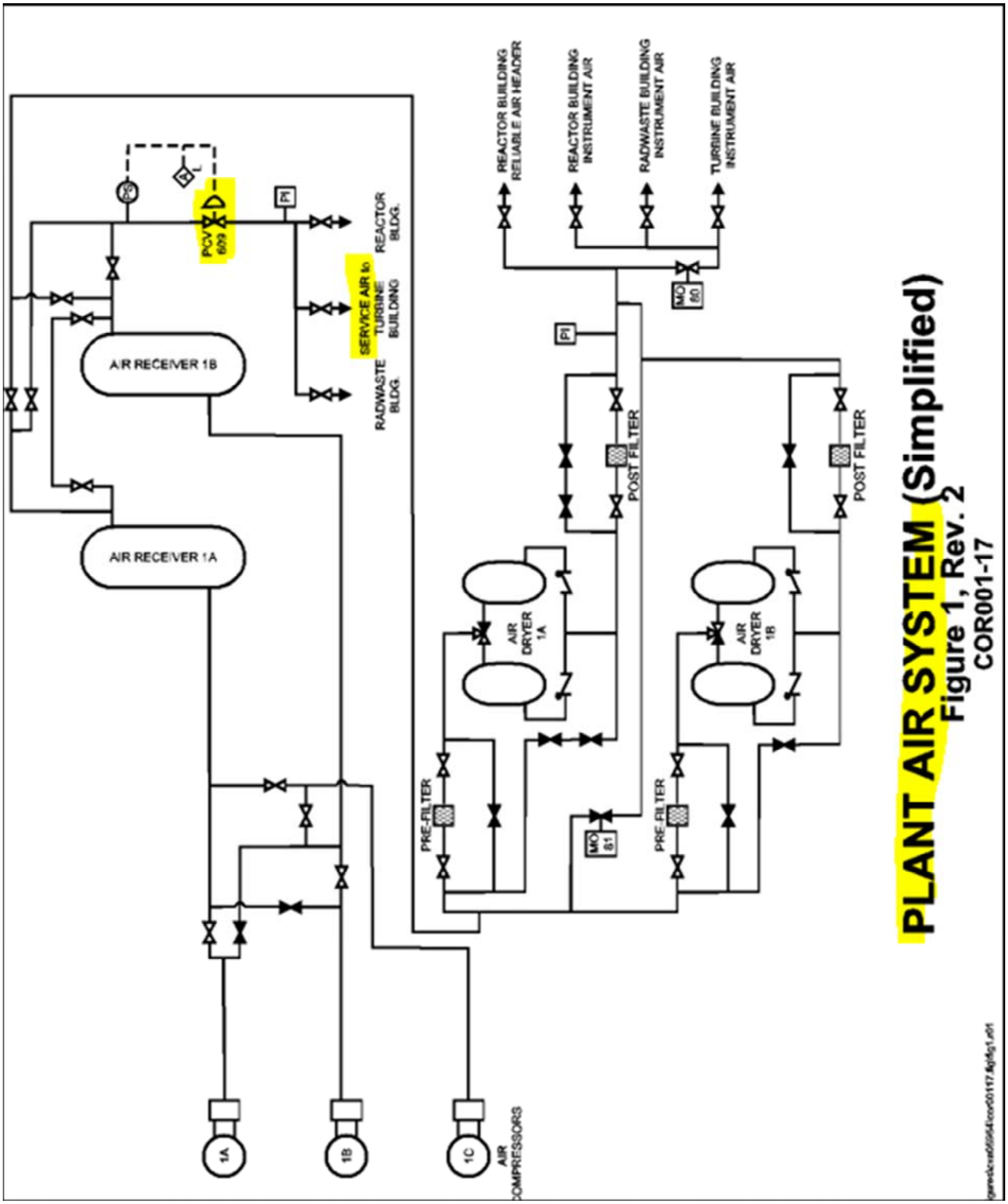
PANEL/WINDOW:
A-4/A-4

1. OPERATOR OBSERVATION AND ACTION

1.1 Verify SAC operating properly.

1.2 Check for excessive air leaks or usage.

1.3 Enter Procedure 5.2AIR.



PLANT AIR SYSTEM (Simplified)
Figure 1, Rev. 2
COR001-17

Examination Outline Cross-Reference	Level	RO
218000 (SF3 ADS) Automatic Depressurization Knowledge of the physical connections and/or cause-effect relationships between AUTOMATIC DEPRESSURIZATION SYSTEM and the following: K1.02 Low pressure core spray: Plant-Specific	Tier#	2
	Group#	1
	K/A #	218000 K1.02
	Rating	4.0
	Revision	0
Revision Statement:		

Question 2

An ATWS is in progress with the following conditions:

- Reactor water level -120 inches, Wide Range
- Reactor pressure 800 psig
- The ONLY ECCS pump running is Core Spray Pump A
- All ADS valves just automatically opened

Which one of the following lists EVERY operator action that will cause ADS valves to automatically close?

A. Place both ADS Inhibit Switches to INHIBIT, ONLY

B. Momentarily depress both ADS Logic Timer Reset buttons simultaneously or place CS Pump A control switch to STOP, ONLY

C. Place both ADS Inhibit Switches to INHIBIT or momentarily depress both ADS Logic Timer Reset buttons simultaneously, ONLY

D. Place both ADS Inhibit Switches to INHIBIT or momentarily depress both ADS Logic Timer Reset buttons simultaneously or place CS Pump A control switch to STOP

Answer: D

Explanation:
This question requires understanding of signals that input into ADS initiation logic and the arrangement of those signals, ADS Logic Timer Reset switches, and ADS inhibit switches within ADS logic. Automatic ADS initiation logic requires reactor water level low +3”, plus reactor water level low-low-low -113”, plus 109 second time delay, plus any low pressure ECCS pump discharge pressure ≥108 psig. For the conditions

given, placing both ADS Inhibit Switches to INHIBIT or simultaneously depressing both ADS Logic Timer Reset buttons or placing CS Pump A control switch to STOP will cause ADS logic relays to de-energize. The contacts from those relays are normally open, so ADS valves lose their open signal when ADS logic relays de-energize, and ADS valves close.

This question is listed as higher cognitive because Examinees who do not understand the ADS logic arrangement have historically exhibited confusion for this topic, because depending on the situation and the question, the answer can be different. For example, if ADS had not yet initiated and the question was what would prevent ADS initiation, momentarily depressing the Timer Logic Reset would not be correct. The examinee usually has to picture the logic and then apply the given conditions.

Distracters:
Answer A is plausible to the examinee who does not know the ADS logic arrangement but who remembers from simulator training that ADS Inhibit Switches are always placed in INHIBIT during ATWS conditions to prevent ADS valves from opening. It is wrong because depressing both ADS Logic Timer Reset buttons or placing CS Pump A control switch to STOP will also cause ADS logic relays to de-energize and ADS valves to close.

Answer B is plausible for the same reason given for distractor A and for the examinee who remembers a low pressure ECCS pump must be operating for ADS to initiate but does not know the arrangement of ADS Logic Timer Relay/Reset contacts in ADS logic. This answer is wrong because depressing both ADS Logic Timer Reset buttons causes ADS initiation relays and the 109 second time delay to pick up relay to drop out, resulting in ADS valves closing.

Answer C is plausible to the examinee who does not know the arrangement of low pressure ECCS pump discharge pressure inputs into ADS logic. Low reactor water level signals can clear after ADS logic has initiated, and ADS valves will remain open because when the 109 second timer elapses, ADS logic seals in around the low water level contacts. If low pressure ECCS pump discharge pressure signals were similarly arranged, the ECCS pumps could be stopped but ADS logic would remain sealed in. This answer is wrong because low pressure ECCS pump discharge pressure contacts are arranged in ADS logic such that the ADS initiation relays are de-energized if no low pressure ECCS pump is running.

Technical References: Lesson plan COR002-16-02 [Ops Nuclear Pressure Relief](Rev 21)

References to be provided to applicants during exam: none

Learning Objective: COR002-16-02 Obj LO-5a, Describe the Nuclear Pressure Relief system design features and/or interlocks that provide for the following: Allows prevention of inadvertent initiation of ADS blowdown.

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(7)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA Applicability:		
Top 10 Risk Significant System – ADS/SRV		

Lesson Title: OPS Nuclear Pressure Relief	
Lesson Number: COR002-16-02	Revision Number: 21

LO-05a

b. ADS may be secured, or prevented from actuating, at any time by placing the ADS A and B Inhibit switches to the "INHIBIT" position. Depressing the ADS Logic A and B Timer Reset pushbuttons will secure the ADS blowdown, if in progress, and will reset the timers to zero. If the initiating conditions still exist, the timer will begin timing down again immediately after it has been reset. Securing all low pressure injection pumps (CS and LPCI) will also cause the ADS to stop a blowdown in progress.

c. ADS logic is powered from 125V DC, with Channel A powered from Panel AA2 and Channel B from Panel BB2. Channel B will automatically transfer to Panel AA2 on loss of power. Channel A does not have an automatic power supply backup.

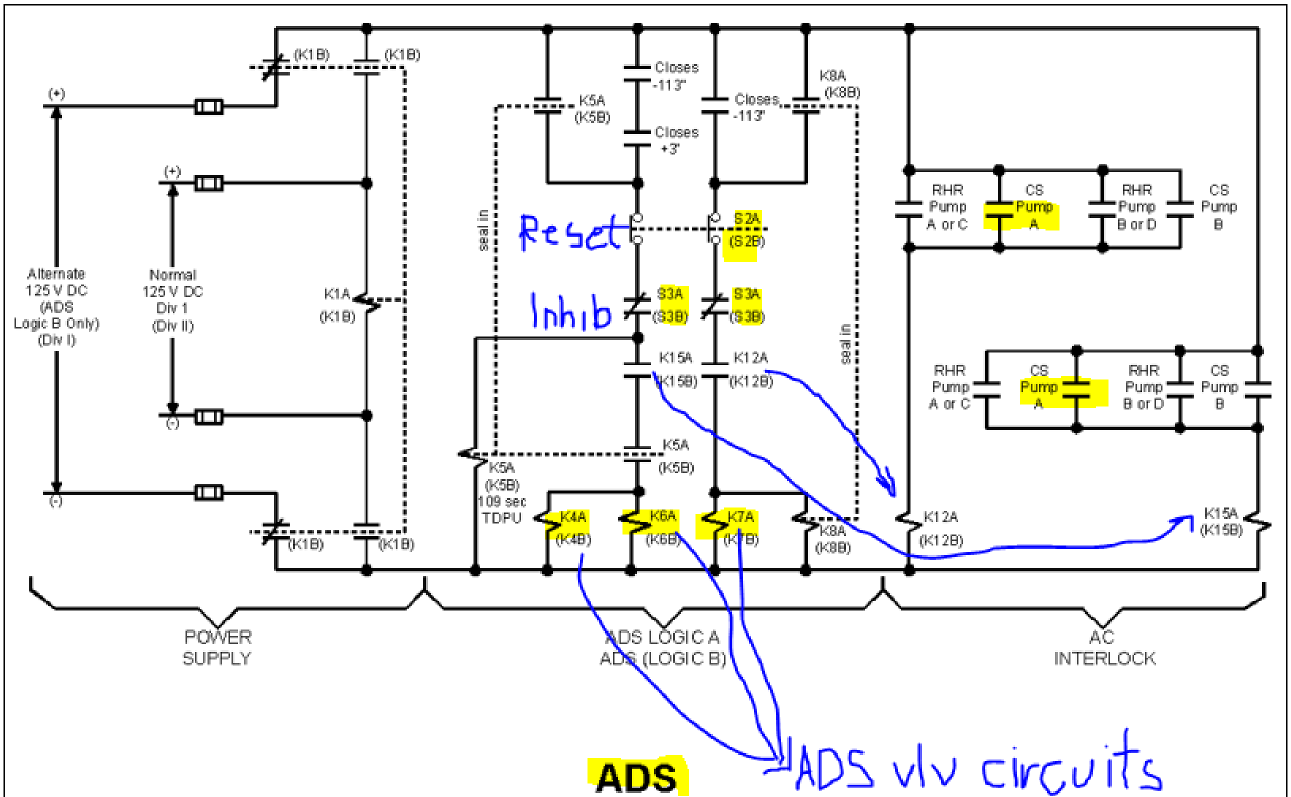


FIGURE 5, REV. 6

COR002-16

Examination Outline Cross-Reference	**Level**	RO
211000 (SF1 SLCS) Standby Liquid Control Ability to (a) predict the impacts of the following on the STANDBY LIQUID CONTROL SYSTEM; and (b) based on those predictions, use procedures to correct, control, or mitigate the consequences of those abnormal conditions or operations: A2.03 A.C. power failures	**Tier#**	2
	Group#	1
	K/A #	211000 A2.03
	Rating	3.2
	Revision	1
Revision Statement: Based on validator and reviewer comments, removed "Boron injection is required", SLC squib valve A status, and removed numbering associated with squib valve B from stem due to unnecessary clutter.		

Question 3

An ATWS is in progress with the following condition:

- MCC-K has lost power

One minute later, the operator places SLC Pump A <u>and</u> B control switches to START.

- White SQUIB VALVE B READY light is ON

Which one of the following describes the status of SLC injection AND which action is required to be performed?

A. SLC Pump A <u>and</u> B are injecting through SLC squib valve V-14A. Inform the CRS when Hot Shutdown boron weight has been injected IAW EOP-6A.

B. <u>Only</u> SLC Pump B is injecting through SLC squib valve V-14A. Inform the CRS when Hot Shutdown boron weight has been injected IAW EOP-6A.

C. SLC is NOT being injected. Inject boron using HPCI IAW Procedure 5.8.8 [Alternate Boron Injection and Preparation].

D. SLC is NOT being injected. Inject boron using RCIC IAW Procedure 5.8.8 [Alternate Boron Injection and Preparation].

Answer: D
Explanation: MCC-K supplies power to SLC Pump A. SLC squib valve V14A is powered by 120 VAC. This power is derived via a 480V/120V transformer from SLC A pump breaker,

breaker 6B on MCC-K. V-14A is normally closed and is opened when the squib is fired by supplying 120 VAC to the squib charge. With MCC-K de-energized, SLC V-14A will not fire when SLC Pump A control switch is placed to START, therefore, it remains closed.

White SQUIB VALVE READY DS-3B (1106B) light is ON, indicating SLC B squib valve V-14B has failed to actuate. Therefore, with both SLC squib valves closed, boron is not being injected with SLC.

With SLC system unavailable, EOP-6A directs boron injection by an alternate method. Procedure 5.5.8 provides two options for alternate boron injection. One option is to use the RWCU system, and the other is to use RCIC with SLC storage tank connected by hose to RCIC pump suction line. MCC-K does not power any valves needed for the lineup involving RCIC. (MCC-K supplies power to MCC-R, which powers RWCU valves required to be operated for alternate boron injection using RWCU; therefore, RCIC must be used.) The CRS directs entry into procedure 5.8.8; however, this question is at the RO level because it only tests knowledge of the overall mitigative strategy of the procedure.

Distracters:
Answer A is plausible because SLC piping is arranged such that either pump will inject via either or both squib valves and because White SQUIB VALVE READY DS-3B (1106B) light is ON, which means SLC is not injecting through that squib valve. An examinee who does not know MCC-K supplies power to SLC Pump A and squib valve A may choose this answer. It is wrong because SLC Pump A is powered from MCC-K and V-14A derives power directly from SLC Pump A breaker 6B on MCC-K, which is de-energized. So, neither SLC Pump A nor B are injecting.

Answer B is plausible because SLC piping is arranged such that either pump will inject via either or both squib valves and because White SQUIB VALVE READY DS-3B (1106B) light is ON, which means SLC is not injecting through that squib valve. SLC Pump B started when its control switch was placed to START. It is plausible that squib valve V-14A could have actuated to the examinee who does not know the squib valve derives power from its associated pump control power. This is plausible because V-14A is powered by 120 VAC, and many other 120 VAC powered valves, such as Rx Bldg to Torus Vacuum Relief valves, derive power directly from 120V power panels. The examinee who knows MCC-K supplies SLC pump A but does not know squib valve V-14A derives power from the pump circuit may choose this answer. It is wrong because V-14A derives power directly from SLC Pump A breaker 6B on MCC-K, which is de-energized; therefore, it will not fire and open. Neither squib valve has opened, so boron is not being injected by SLC Pump B.

Answer C is plausible because alternate boron injection is required and HPCI is a steam driven system, like RCIC, and in its standby alignment does not rely on power from MCC-K. It is wrong because procedure 5.8.8 does not contain provisions for alternate boron injection using HPCI.

Technical References: EOP-6A [RPV Pressure/Reactor Power(Failure-to-Scram)](Rev 19), Procedure 2.2A_480.RX [480 VAC Reactor Building Breaker Checklist](Rev 22), GE dwg 791E262 sh 1, Procedure 5.8.8 [Alternate Boron Injection and Preparation](Rev 17), Procedure 2.2A_120CRIT.DIV1 [120/240 VAC Critical Instrument Power Checklist (Div 1)](Rev 10), Procedure 2.2.74 [Standby Liquid Control System](Rev 56), procedure 5.3AC480 [480 VAC Bus Failure](Rev 55), procedure 2.2.66A [Reactor Water Cleanup Component Checklist](Rev 21)		
References to be provided to applicants during exam: none		
Learning Objective: COR002-29-02 Obj LO-10c, Predict the consequences a malfunction of the following would have on the SLC system: AC power		
Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(6)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA Applicability:		
Top 10 Risk Significant System – Emergency AC Power		

6. STARTING SLC INJECTION

6.1 Place SLC PUMP A in service (Panel 9-5).

6.1.1 Ensure green hooded blank key removed from SLC PUMP A keylock switch.

6.1.2 Place Key 54 operating key in SLC PUMP A keylock switch and place switch to START.

6.1.3 Check SLC PUMP A starts.

6.1.4 Check white SQUIB VALVE READY DS-3A (1106A) light turns off.

6.2 Place SLC PUMP B in service (Panel 9-5).

6.2.1 Ensure green hooded blank key removed from SLC PUMP B keylock switch.

6.2.2 Place Key 55 operating key in SLC PUMP B keylock switch and place switch to START.

6.2.3 Check SLC PUMP B starts.

6.2.4 Check white SQUIB VALVE READY DS-3B (1106B) light turns off.

6.3 Check pressure on SLC-PI-65, PUMP PRESSURE (Panel 9-5), is greater than reactor pressure.

6.4 Check Annunciator 9-5-2/G-7, LOSS OF CONT TO SQUIB VLVS, alarms.

6.5 Ensure RWCU-MO-15, INBD ISOL VLV (Panel 9-4), is closed.

6.6 Ensure RWCU-MO-18, OUTBD ISOL VLV (Panel 9-4), is closed.

6.7 Ensure both RWCU pumps are off (Panel 9-4).

6.8 Ensure RWCU-MO-74, DEMIN SUCTION BYPASS VLV (Panel 9-4), is throttled open.

7. STOPPING SLC INJECTION

7.1 WHEN operation of SLC System is <u>no</u> longer required, THEN perform Steps 7.2 through 7.8.

7.2 (Independent Verification) Place SLC PUMP A keylock switch to STOP and check it stops.

Performed By: ________

Verified By: ________

ATTACHMENT 1 REACTOR BUILDING BREAKER CHECKLIST DIVISION 1

BREAKER	DESCRIPTION	NORMAL POSITION	PERFORMED BY	VERIFIED BY	COMMENTS
EE-MCC-K(3C)	REC-P-1A RX EQUIP COOLING PUMP 1A	ON			
EE-MCC-K(4A)	EF-R-1E SGT EXHAUST FAN 1A	ON			
EE-MCC-K(4BL)	NORMAL FEED TO LTG PNL LPREMF	ON			
EE-MCC-K(4D)	REC-P-1B RX EQUIP COOLING PUMP 1B	ON			
EE-MCC-K(5A)	SGT-HTR-1A-A SGT A 2.8 KW ELECTRIC HEATER (1-SGH-R-1A-A)	ON			
EE-MCC-K(5B)	SGT-HTR-1A-B SGT A 5 KW ELECTRIC HEATER (1-SGH-R-1A-B)	ON			
EE-MCC-K(5CL)	SPARE	OFF			
EE-MCC-K(5CR)	SPARE	OFF			
EE-MCC-K(5D)	SLC-HTR-TK SLC STORAGE TANK HEATER	ON			
EE-MCC-K(6A)	SLC-P-1A STANDBY LIQUID CONT. PUMP 1A	ON			

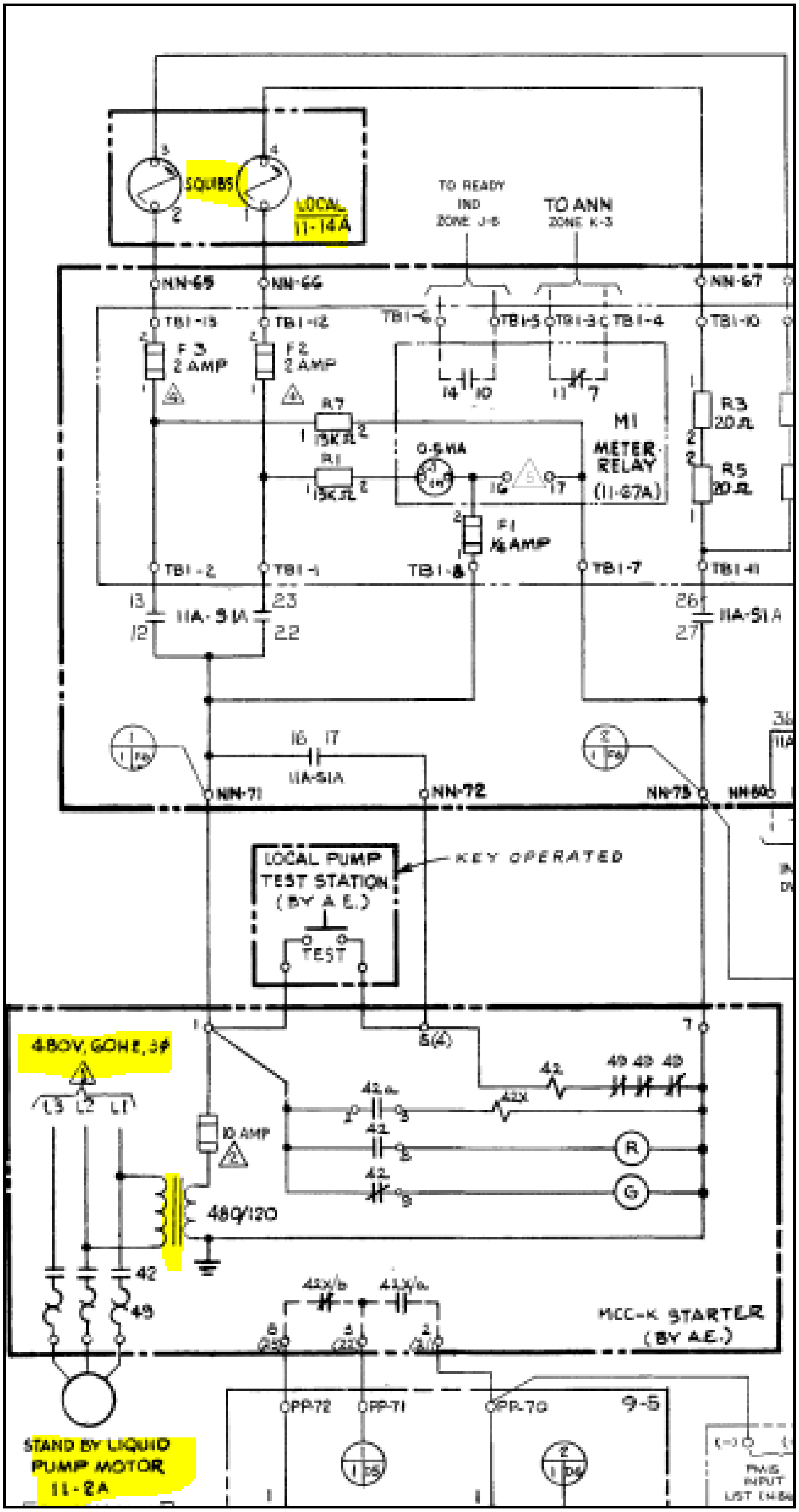
MCC-K	
MCC-Q	
PC-MO-305 Bypass For PC-MO-230	
Reactor Building Floor Drain Sump Pumps 1A1 and 1B1	
DG Fuel Oil Transfer Pump 1A	Effects OPERABILITY of DGs.
Core Spray A FCU	
NW QUAD-RHR Room FCU	
Security System	
REC Pumps 1A and 1B	

PROCEDURE 5.3AC480 REVISION 55 PAGE 24 OF 50

ATTACHMENT 9 480V BUS 1F - MAJOR LOADS

LOADS	NOTES
SGT Exhaust Fan 1A	
Lighting Panel LPREMF	
SGT A Heaters	Both 2.8 kW and 5 kW.
SLC Storage Tank Heater	
SLC Pump 1A	
Drywell FCUs 1A and 1C	
MCC-RA	
MCC-R	
FPC Pump 1A	

From GE dwg 791E262 sh 1



From EOP-6A

BORON INJECTION
IS REQUIRED

FS/Q-13

1. Inject boron into RPV with SLC
2. Record initial SLC tank level
3. Inhibit ADS

1

FS/Q-14

IF SLC tank level drops to 0%	THEN trip SLC pumps
IF boron cannot be injected with SLC	THEN inject boron into RPV using RWCU or RCIC, EOP 5.8.8

CNS OPERATIONS MANUAL EMERGENCY OPERATING PROCEDURE 5.8.8 ALTERNATE BORON INJECTION AND PREPARATION	USE: REFERENCE QUALITY: QAPD RELATED EFFECTIVE: 10/13/15 APPROVAL: ITR-RDM OWNER: OSG SUPV DEPARTMENT: OPS

1. PURPOSE

1.1 This procedure provides instruction for Alternate Boron Injection using the RWCU and RCIC Systems. It also provides a method for emergency preparation of Sodium Pentaborate.

2. REQUIREMENTS

2.1 EOP Flowchart 6A or 6B has directed Operator to inject boron with an Alternate Boron Injection System.

2.2 SLC System unavailable for boron injection into RPV.

2.3 During performance of procedure, it may be necessary to perform Section 8, Emergency Sodium Pentaborate Preparation. Performance of section requires Chemistry, Warehouse, and Utility personnel. Contact TSC for assistance in coordinating and performing Section 8.

2.4 Ensure following equipment and materials are available, as needed:

2.4.1 Grand Master Key (SO Key Ring or Key 12 or 25 in CR SM Key Locker) for Auxiliary Relay Room.

2.4.2 J423 Key (SO Key Ring or Key 36 or 58 in CR SM Key Locker) (PTM box padlock).

2.4.3 Flat tipped screwdriver.

2.4.4 Two spanner wrenches (one stored on top of each of the two Alternate Boron Injection hose reels).

7. ALTERNATE BORON INJECTION WITH RCIC

CAUTION 1 – This section may require dispatching personnel through or into potentially high radiation areas.

CAUTION 2 – PC O_2 levels may rise during RCIC gland seal vacuum pump operation.Ⓟ[1]

7.1 Refer to Section 3 when dispatching personnel to perform actions outside Control Room.

7.2 Perform Steps 7.3 and 7.4 concurrently.

NOTE 1 – Hose should be run to maintain as much of a upward slope as possible to allow any air in line to vent into SLC tank when line is filled due to opening of SLC-17.

NOTE 2 – Hose run pictures may be seen in Attachment 1, Alternate Boron Injection With RCIC Hose Route.

7.3 Establish a flow path from SLC tank to RCIC pump suction as follows:

7.3.1 Ensure SLC-17, TANK DRN, is closed (R-976-East).

7.3.2 Remove drain cap on outlet of SLC-17 and attach Alternate Boron Injection hose obtained from dedicated hose reel on R-976-East.

7.3.3 Thread hose through pipe chase just to right of SLC Pump B control switch on R-976-East and route it straight down to elevation 903. Route for hose is clearly marked with black signs posted on 976, 958, and 932 levels of Reactor Building. Hose will emerge on 903 level in an area about 15' south of Reactor Building Elevator.

7.3.4 Connect hose dropped from 976 level of Reactor Building to Alternate Boron Injection hose obtained from dedicated hose reel on 903 level of NE Quad stairwell.

7.3.5 Thread second hose through R-903-NE Quad door and down to elevation 859 between stairs.

NOTE – Drain line has enough flexibility to allow free rotation of 90° elbow.

7.3.6 Using two pipe wrenches obtained from R-903-NE Quad Alternate Boron Injection hose reel, remove 90° elbow from end of pipe on outlet of RCIC-179, RCIC PUMP SUCTION STRAINER DRAIN SHUTOFF (R-859-NE QUAD).

7.3.7 Attach hose to end of pipe on outlet of RCIC-179, RCIC PUMP SUCT. STRN. DRN. SHUTOFF (R-859-NE QUAD).

7.3.8 Inform CRS that Alternate Boron Injection line from SLC tank to RCIC suction is installed.

CAUTION – Monitor Reactor Water Level closely while performing following valve lineup.

7.4 Ensure RCIC aligned for SLC injection by performing following:

7.4.1 Ensure RCIC pump is running (PNL 9-4).

7.4.2 Ensure RCIC-MO-20, PUMP DISCH VLV, is OPEN.

7.4.3 Ensure RCIC-MO-21, PUMP DISCH TO RX VLV, is OPEN.

7.4.4 Ensure RCIC-MO-30, TEST BYP TO ECST VLV, is CLOSED.

7.4.5 Ensure RCIC-MO-33, ECST TEST LINE SHUTOFF VLV, is CLOSED.

7.4.6 Ensure RCIC-MO-27, MIN FLOW BYP VLV, is CLOSED.

7.4.7 Open breakers for following valves (R-903-NE, RCIC STARTER RACK):

7.4.7.1 RCIC-MO-33, ECST TEST LINE SHUTOFF.

7.4.7.2 RCIC-MO-27, MIN FLOW BYP VLV.

7.5 Ensure one or both of following:

7.5.1 RWCU-MO-MO15, SUPPLY INBOARD ISOLATION, closed.

7.5.2 RWCU-MO-MO18, SUPPLY OUTBOARD ISOLATION, closed.

7.6 Commence Alternate Boron Injection by opening following valves:

7.6.1 SLC-17, TANK DRN (R-976-E).

7.6.2 RCIC-179, RCIC PUMP SUCT. STRN. DRN. SHUTOFF (R-859-NE QUAD).

7.6.3 RCIC-47, RCIC PUMP SUCT. STRN. DRN. ROOT (R-859-NE QUAD).

7.7 Economize operation of other RPV injection sources to maximize RCIC Alternate Boron Injection rate and maintain a given level band to avoid RPV overfill.

7.8 Inform CRS that RCIC is now injecting to RPV with borated water.

7.9 WHEN directed by CRS, THEN secure Alternate Boron Injection lineup as follows:

7.9.1 Close SLC-17, TANK DRN (R-976-EAST).

7.9.2 Close RCIC-179, RCIC PUMP SUCT. STRN. DRN. SHUTOFF (R-859-NE QUAD).

7.9.3 Close RCIC-47, RCIC PUMP SUCT. STRN. DRN. ROOT (R-859-NE QUAD).

ATTACHMENT 2 PANEL CCP1A BREAKER CHECKLIST

CCP-1A - (CABLE SPREADING ROOM) FED FROM CDP-1A(3)

BREAKER NUMBER	DESCRIPTION	NORMAL POSITION	PERFORMED BY	VERIFIED BY	COMMENTS
1	PANEL 9-3 AND 9-21	ON			
2	PANEL 9-4	ON			
3	PANELS 9-18 AND 9-19, VBD-M	ON			
4	RACK 25-59 (PRIMARY CONTAINMENT COOLING AND NITROGEN INERTING SYSTEM), SGT SYSTEM 1A	ON			
5	VBD-M (RHR HX VALVE)	ON			
6	PANEL B (TURBINE DRAIN VALVES DRV-SP-1 TO DRV-SP-8) (PLUG MOLD)	ON			
7	VBD-K (SGT SYSTEM 1A CONTROL AND OFF GAS DILUTION FAN DF-OG-1A)	ON			
8	VBD-M	ON			
9	VBD-H (NITROGEN INERTING SYSTEM AND TORUS VACUUM RELIEF VALVE CONTROLS)	ON			

PROCEDURE 2.2A_120CRIT.DIV1 REVISION 10 PAGE 4 OF 12

ATTACHMENT 2 POWER SUPPLY CHECKLIST

DESCRIPTION	POWER SUPPLY	NORMAL POSITION	PERFORMED BY	VERIFIED BY	COMMENTS
PANEL 9-17	EE-PNL-RPSPP1B(2)	ON			
PANEL 9-4	EE-PNL-CPP(1)	ON			
PANELS 9-18 AND 9-19	EE-PNL-CPP(9)	ON			
PANEL 9-4	EE-PNL-CCP1A(2)	ON			
PANELS 9-18 AND 9-19, VBD-M	EE-PNL-CCP1A(3)	ON			
PANEL 9-4	EE-PNL-CCP1B(2)	ON			
RWCU-MO-15 RWCU INBOARD ISOLATION VALVE (CU-600MV)	EE-MCC-R(5C)	ON			
RWCU-MO-74 RWCU FILTER DEMIN BYPASS VALVE (CU-602MV)	EE-MCC-R(5D)	ON			
RWCU-MO-68 RWCU RETURN LINE VALVE TO REACTOR (RF-603MV)	EE-MCC-R(6A)	ON			
RWCU-MO-53 BLOWDOWN ORIFICE BYPASS (CU-604MV)	EE-MCC-R(6B)	ON			

PROCEDURE 2.2.66A REVISION 21 PAGE 8 OF 49

Examination Outline Cross-Reference	Level	RO
239002 (SF3 SRV) Safety Relief Valves Ability to predict and/or monitor changes in parameters associated with operating the RELIEF/SAFETY VALVES controls including: A1.06 Reactor power	Tier#	2
	Group#	1
	K/A #	239002 A1.06
	Rating	3.7
	Revision	0
Revision Statement:		

Question 4

The plant is at 100% power when SRV 71D fails open.

Which one of the following describes how reactor power responds to this event?

A. Drops lower, then rises to greater than 100%

B. Rises higher, then rises to greater than 102%

C. Rises higher, then lowers and stabilizes at less than 100%

D. Drops lower, then lowers and stabilizes at less than 98%

Answer: A
Explanation: When the SRV opens, MSL pressure lowers slightly, resulting in reactor pressure lowering slightly, which increases voids, causing power to promptly fall several percent. The initial transient low is short lived due to response of the DEH system. Equalizing header pressure will fall, causing turbine governor valves to close to restore pressure to the DEH setpoint, which results in reactor pressure rising, void collapse, and power to return to near 100%. Steam flow through the open SRV results in reduced turbine steam flow and reduced extraction steam. This results in reduced feedwater heating. As feedwater temperature lowers, core inlet subcooling is reduced, resulting in a slight upward shift of the core boiling boundary. Power slowly rises until feedwater temperature stabilizes. Although reactor pressure stabilizes a lower value than it was initially, which would otherwise result in a lower final power level, the effects of reduced feedwater temperature outweigh the pressure effect, so final power level is higher than the initial power level.
Distracters:

Answer B is plausible to the examinee who considers the effect of reduced feedwater temperature but fails to consider the initial effect of void production. It is wrong because the prompt reduction in reactor pressure is the first effect on power, causing it to initially lower.

Answer C is plausible because one of the first operator actions required by Procedure 2.4SRV is to lower power to <90%, which is mainly to accommodate the effect of the reactor pressure rise when subsequent actions are taken to close the SRV, but also provides margin to the licensed thermal power limit due to the reduction in feedwater temperature. The examinee who remembers this action but not its reason, or who confuses the effects of SRV operation on core voids, power, and/or feedwater temperature and reverses the overall effects of the transient may choose this answer. It is wrong because power initially lowers due the pressure reduction and resulting core voiding, then it slowly rises as feedwater temperature lowers due to reduction of extraction steam caused by reduced turbine steam flow.

Answer D is plausible to the examinee who understands the initial effect of the SRV opening on reactor pressure and voiding but who does not understand the net effects on feedwater temperature. An examinee may believe the final power will be lower because the final reactor pressure is lower. This answer is wrong because the power increase caused by reduced feedwater temperature results in a net increase in reactor power.

Technical References: Procedure 2.4SRV [Stuck Open Relief Valve](Rev 15)

References to be provided to applicants during exam: none

Learning Objective: COR002-16-02 Obj LO-4f, Given a Nuclear Pressure Relief system component manipulation, predict the changes in the following parameters: Reactor power

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(5)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	

PSA Applicability:

Top 10 Risk Significant System – ADS/SRV

ATTACHMENT 1 INFORMATION SHEET

ATTACHMENT 1 INFORMATION SHEET

1. DISCUSSION

1.1 This procedure addresses the failure of a reactor vessel relief valve(s) to close after it has opened. This procedure does not address relief valves that fail to open when required or relief valves that suddenly begin leaking. These events are addressed by other procedures and processes.

1.2 Be aware that closing a relief valve with the reactor critical will cause a rise in reactor pressure and positive reactivity addition.

1.3 PROBABLE ANNUNCIATORS

1.3.1 9-3-1/A-2, RELIEF VALVE OPEN.

1.3.2 9-3-1/C-1, SAFETY/RELIEF VALVE LEAKING.

1.3.3 9-3-1/F-2, ADS FAULTY TEST PROCEDURE.

1.3.4 9-3-2/F-5, SUPPR POOL NR/WR HIGH LEVEL.

1.3.5 9-3-2/G-5, SUPPR POOL NR/WR LOW LEVEL.

1.3.6 J-1/A-1, SUPPR POOL DIV I WATER HIGH TEMP.

1.3.7 J-1/A-2, SUPPR POOL DIV II WATER HIGH TEMP.

1.3.8 J-1/A-3, SUPPR CHAMBER HIGH PRESSURE.

1.3.9 J-1/B-3, SUPPR CHAMBER HIGH AIR TEMP.

1.4 PROBABLE INDICATIONS

1.4.1 PMIS indicates any of following when RV should be closed:

1.4.1.1 RV open, Points D556 through D563.

1.4.1.2 High tailpipe temperature, Points T142 through T149.

1.4.1.3 RV indicates open or high tailpipe temperature, SPDS10.

1.4.1.4 Suppression pool high water temperature/level alarm, SPDS08.

1.4.2 High tailpipe temperature on MS-TR-166, MAIN STEAM RELIEF AND SAFETY VALVE LEAK TEMP RECORDER.

1.4.3 Drop in turbine generator output.

Examination Outline Cross-Reference	Level	RO
262002 (SF6 UPS) Uninterruptable Power Supply (AC/DC) Knowledge of UNINTERRUPTABLE POWER SUPPLY (A.C./D.C.) design feature(s) and/or interlocks which provide for the following: K4.01 Transfer from preferred power to alternate power supplies	**Tier#**	2
	Group#	1
	K/A #	262002 K4.01
	Rating	3.1
	Revision	0
Revision Statement:		

Question 5

Plant is at 100% power.

Regarding the No-Break Power System…

(1) Which signal sensed on the output of the NBPP Inverter will cause it to automatically transfer to the alternate supply?

AND

(2) What is the alternate power supply to NBPP?

A. (1) Overvoltage
(2) MCC-R

B. (1) Overvoltage
(2) MCC-S

C. (1) Overcurrent
(2) MCC-R

D. (1) Overcurrent
(2) MCC-S

Answer: A

Explanation:
The No-Break Power system provides power at 115VAC/230 VAC for equipment and instrumentation which must have an uninterruptible power supply. An emergency (alternate) AC power source for the NBPP #1 is provided from MCC-R through a step-down transformer in the event that inverter 1A fails.

A static switch inside the inverter transfers to the alternate power source when inverter output voltage or frequency is not within limits specified for safe system operations. An automatic transfer from the inverter to the AC supply will occur on any of the following:

- an overvoltage or undervoltage of ± 10%
- an overfrequency or underfrequency of ± 2 cycles

Distracters:
Answer B part 1 is correct. Part 2 is plausible because MCC-R is fed through an ESF bus that can be supplied by a DG, and MCC-S is also fed through an ESF bus that can be supplied by a DG. It is wrong because MCC-R is the alternate supply to the NBPP, not MCC-S.

Answer C part 1 is plausible because inverter failure will cause the NBPP to transfer to its alternate supply, and inverter failure would be caused by low battery DC input voltage to the inverter, which would correspond to high DC input current to the inverter. It is wrong because overcurrent is not sensed on the inverter output. Part 2 is correct.

Answer D part 1 is plausible and wrong for the reasons given for distractor C. Part 2 is plausible and wrong for the reasons given for distractor B.

Technical References: Procedure 2.2.22 [Vital Instrument Power System](Rev 80), Lesson plan COR001-01-01 [Ops AC Electrical Distribution](Rev 50), Procedure 5.3AC480 [480 VAC Bus Failure](Rev 55)

References to be provided to applicants during exam: none

Learning Objective: COR001-01-01 Obj LO-6c, Describe the interrelationship between the AC Electrical Distribution System and the following: No Break Power Supply; 10e, Briefly describe the following concepts as they apply to AC Electrical Distribution System: Static Switch operation; 17e, Describe the effect of the following on No Break Power Supply operation: High No Break Power Supply voltage

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	

10CFR Part 55 Content:	55.41(b)(4)
Level of Difficulty:	3

SRO Only Justification:	N/A
PSA Applicability:	
N/A	

1.2.5 The No Break Power Panel (NBPP) operates from power supplied by an inverter and an AC supply (MCC-R) as alternate source. The alternate AC supply can automatically feed NBPP without interruption. A static switch inside the inverter transfers to the alternate power source when inverter output voltage or frequency is not within limits specified for safe system operations.

PROCEDURE 2.2.22 REVISION 80 PAGE 61 OF 65

G. No-Break Power System

1. The No-Break Power system provides power at 115VAC/230 VAC for equipment and instrumentation which must have an uninterruptible power supply.

2. Power Supplies

   a. Power to the No-Break Power Panel (NBPP) #1 is normally supplied from 250 VDC bus 1A through inverter 1A and a static switch.

   b. An emergency (alternate) AC power source for the NBPP #1 is provided from MCC-R through a step-down transformer in the event that inverter 1A fails.

   c. An automatic transfer from the inverter to the AC supply will occur on any of the following:

      1) the inverter fails (low battery/DC supply voltage, overcurrent)

      2) the inverter is turned off,

      3) an overvoltage or undervoltage of ± 10%,

      4) an overfrequency or underfrequency of ± 2 cycles.

esson Title: OPS AC Electrical Distribution	
esson Number: COR001-01-01	Revision Number: 50

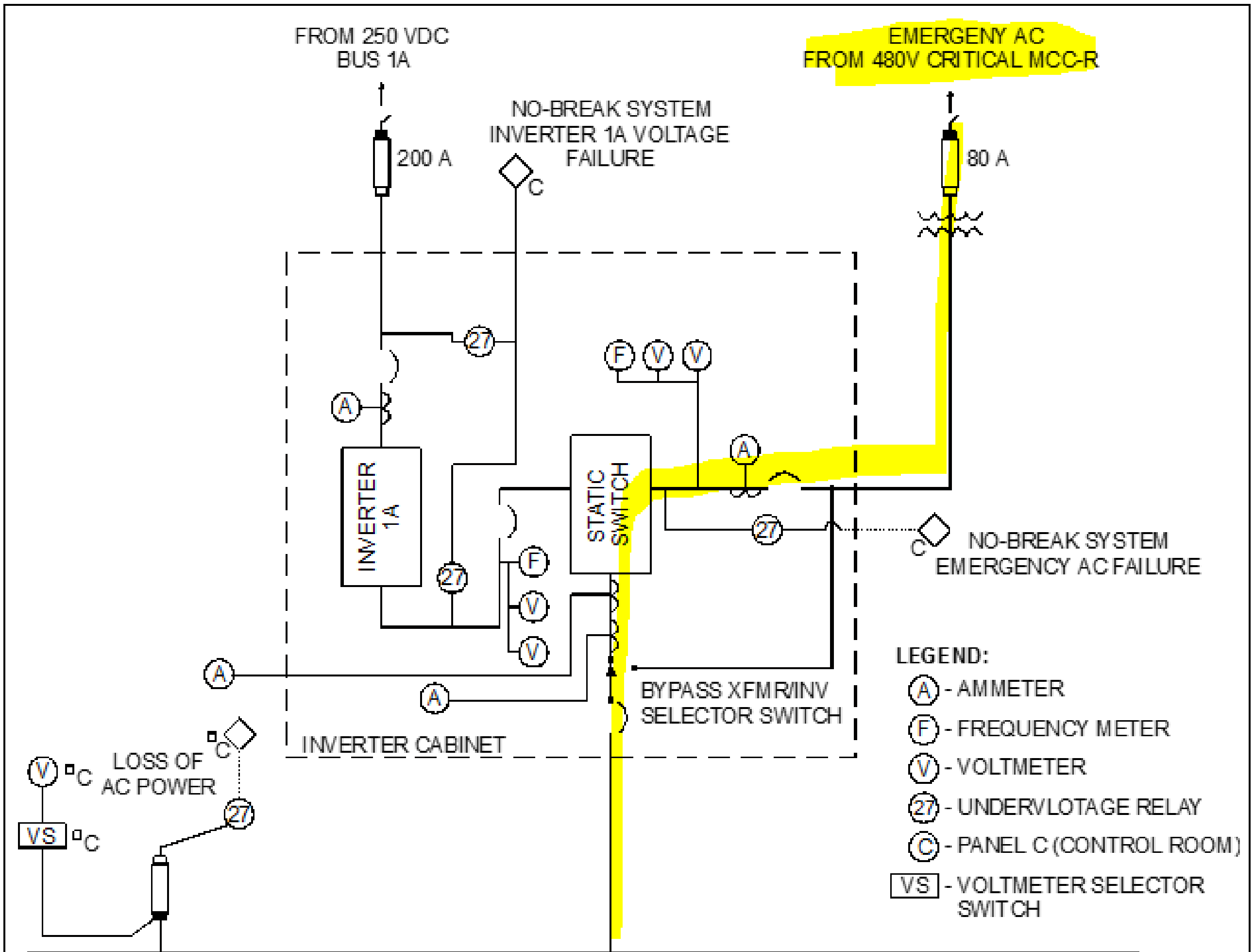
   d. There is no automatic transfer from the emergency AC source to the inverter. There are no automatic actions that occur due to a high or low voltage condition - only an alarm. If the NBPP loses power, vessel level will experience a transient due to the condensate and condensate booster pump minimum flow valves failing open due to loss of power, however the plant is expected to stabilize without the need for manual reactor scram insertion. (See Emergency Procedure 5.3NBPP)

ATTACHMENT 9 480V BUS 1F - MAJOR LOADS

LOADS	NOTES
MCC-R	
NBPP (Alternate Supply)	
Reactor Building Floor Drain Sump Pump 1A2	
Reactor Building Floor Drain Sump Pump 1B2	
Reactor Building Floor Drain Sump Pump 1C1	
Reactor Building Floor Drain Sump Pump 1D1	
RHR-MO-20 RHR A and B Crosstie	
RHR-MO-57 RHR Discharge To Radwaste Outboard Isolation	
RHR-MO-274B Loop B Testable Check Bypass	
SW-MO-886 SW Supply To REC North Critical Loop	
MS-MO-74 MSL Drains Inboard Isolation	
MS-MO-79 MSL Drains RO Bypass	
HPCI-MO-15 HPCI Inboard Steam Supply	
MS-MO-78 MSL Drains Outboard Throttle Valve	
RWCU-MO-15 RWCU Inboard Isolation	
RWCU-MO-74 RWCU F/D Bypass	
RWCU-MO-68 RWCU Return	
RWCU-MO-53 Blowdown Orifice Bypass	
RWCU-MO-56 Blowdown To Main Condenser	
RWCU-MO-57 Blowdown To RW	
RHR-MO-18 SDC Supply Inboard Isolation	
REC-MO-700 NON-CRIT Header Supply	
REC-MO-702 REC Drywell Supply	
REC-MO-709 REC Drywell Return	
REC-MO-695 Critical Loops Supply X-Tie	
REC-MO-694 Critical Loops Return X-Tie	

ATTACHMENT 11 480V BUS 1G - MAJOR LOADS

LOADS	NOTES
MCC-S	
MCC-RB	
MCC-Y	
HPCI Room Fan Coil Unit	
EF-R-1F SGT Exhaust Fan 1B	
Reactor Building Sump Pump 1D2	
SLC Pump 1B	
FPC Pump 1B	
CS-B Room FCU	
DG Fuel Oil Transfer Pump 1B	Effects OPERABILITY of DGs.
Reactor Building Sump Pump 1C2	
SGT B Electric Heaters	
SW QUAD-RHR Room FCU	
REC Pumps 1C and 1D	
MCC-RA (Emergency Feeder)	
Drywell FCUs 1B and 1D	
Lighting Panel LPREMG	
MCC-R (Emergency Feeder)	
MCC-T	
MCC-X	
Instrument Air Dryer A	
AC-C-1F Computer Room ACU 1F Compressor	
HP Seal Oil Backup Pump	
SS-XFMR-UPS2	
RPS B MG Set	
Computer Room ACU 1D Condenser	
SA-MO-81 Service Air To Instrument Air Tie	



NO-BREAK POWER SYSTEM

Figure 7, Rev. 9

COR001-01

Examination Outline Cross-Reference	Level	RO
223002 (SF5 PCIS) Primary Containment Isolation/Nuclear Steam Supply Shutoff Ability to monitor automatic operations of the PRIMARY CONTAINMENT ISOLATION SYSTEM/NUCLEAR STEAM SUPPLY SHUT-OFF including: A3.02 Valve closures	**Tier#**	2
	Group#	1
	K/A #	223002 A3.02
	Rating	3.5
	Revision	0
Revision Statement:		

Question 6

RCIC is injecting at rated flow following a scram from 100% power.

The following annunciator is received due to a pipe break:

RCIC
STEAM LINE
HIGH D/P

PANEL/WINDOW:
9-4-1/A-2

Which of the RCIC valves listed below **CLOSE** as a result of this condition?

- RCIC-MO-15 [Inbd Stm Supp Isol Vlv]
- RCIC- MO-16 [Outbd Stm Supp Isol Vlv]
- RCIC-MO-21 [Pump Disch to Rx Vlv]
- RCIC Turbine Trip & Throttle Valve

A. RCIC-MO-15 **and** RCIC-MO-16, ONLY

B. Turbine Trip & Throttle Valve **and** RCIC-MO-21, ONLY

C. RCIC-MO-15 **and** RCIC-MO-16 **and** RCIC-MO-21, ONLY

D. RCIC-MO-15 **and** RCIC-MO-16 **and** Turbine Trip & Throttle Valve, ONLY

Answer: D
Explanation: RCIC steam line high flow, 288%, is a Group 5 isolation signal. High RCIC steam line flow is sensed by D/P instrumentation and also actuates the subject annunciator at

the isolation setpoint. A pipe break would result in both channels of Group 5 logic tripping. Group 5 Channel A closes RCIC-MO-16. Channel B closes RCIC-MO-15. An automatic isolation signal from Channel A while RCIC is operating results in a RCIC Turbine Trip, which closes the Turbine Trip & Throttle Valve.

Distracters:
Answer A is plausible because both channels of Group 5 logic tripping closes RCIC-MO-15 and MO-16. It is wrong because an isolation of Group 5 Channel A also causes the Turbine Trip & Throttle Valve to close.

Answer B is plausible because actuation of Group 5 logic closes the Turbine Trip & Throttle Valve, which shuts off the steam supply to RCIC turbine. An examinee believe the Trip & Throttle Valve will isolate the steam leak. An examinee may also believe injection valve MO-21 closes on a Group 5 signal or when RCIC turbine trips, since minimum flow valve MO-27 automatically closes on a RCIC turbine trip. This answer is wrong because MO-15 and MO-16 isolate on a Group 5 signal and because MO-21 does not automatically close.

Answer C is plausible because MO-15 and MO-16 close upon a Group 5 signal and because an examinee may believe injection valve MO-21 also automatically closes on a Group 5 signal or when RCIC turbine trips. It is wrong because MO-21 does not automatically close and because the Turbine Trip & Throttle Valve does automatically close for this event.

Technical References: Lesson plan COR002-18-02 [Ops Reactor Core Isolation Cooling](Rev 32), procedure 2.1.22 [Recovering from a Group Isolation](Rev 63), Alarm Card 9-4-1/A-2 [RCIC Steam Line High D/P](Rev 59)

References to be provided to applicants during exam: none

Learning Objective: COR002-18-02 Obj. LO-10r, Predict the consequences of the following on the RCIC System: PCIS isolation signal

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(7)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	

PSA Applicability:
Top 10 Risk Significant Systems – PCIS, RCIC

PROCEDURE 2.3_9-4-1	REVISION 59	PAGE 4 OF 69

RCIC STEAM LINE HIGH D/P	PANEL/WINDOW: 9-4-1/A-2

1. AUTOMATIC ACTIONS

   1.1 Initiates RCIC auto isolation, Group 5.

      1.1.1 Closes RCIC-MO-15, INBD STM SUPP ISOL VLV.

      1.1.2 Closes RCIC-MO-16, OUTBD STM SUPP ISOL VLV.

      1.1.3 Trips RCIC Turbine.

2. OPERATOR OBSERVATION AND ACTION

   2.1 Enter Procedure 2.1.22.

   2.2 AFTER RCIC steam lines have been examined, THEN reset Group 5 isolation per Procedure 2.1.22.

8. GROUP 5 ISOLATION

8.1 Upon 1/2 Group 5 Isolation, following will occur:

NOTE – Manual actuation of Group 5 Isolation (Panel 9-4) trips Logic A only.

8.1.1 If Logic A trips:

8.1.1.1 RCIC-MO-16, OUTBD STM SUPP ISOL VLV, closes.

8.1.1.2 RCIC turbine trips.

8.1.2 If Logic B trips, RCIC-MO-15, INBD ISOL VLV, closes.

8.2 Upon full Group 5 Isolation, ensure following valves have closed (Panel 9-4):

8.2.1 RCIC-MO-16, OUTBD STM SUPP ISOL VLV.

8.2.2 RCIC-MO-15, INBD ISOL VLV.

8.3 Ensure RCIC turbine has tripped.

8.4 Determine isolation cause:

ISOLATION	ALLOWABLE VALUE
RCIC Steam Line Space High Temperature	≤ 195°F
RCIC Steam Line High Flow	≤ 288%
RCIC Steam Supply Low Pressure	≥ 61 psig

Fig 13	10.	Minimum Flow Valve (MO-27)
LO-08c, LO-10k	a.	This valve is used to maintain a minimum cooling flow through the RCIC pump to the suppression chamber.
LO-06a	b.	This valve is powered from the 125V DC RCIC starter rack.
LO-12d	c.	Interlocks

(1) Two conditions will cause the minimum flow valve to automatically open.

(a) Valve MO-27 receives an open signal if a low-flow condition (< 40 gpm) is present with an RCIC pump discharge pressure greater than 125 psig.

(b) The valve will also open automatically if a low-flow condition is present with a system initiation signal.

(2) The valve closes when system flow is 80 gpm and increasing or upon an RCIC turbine trip signal which actuates the trip solenoid.

Lesson Number:	COR002-18-02	Revision:	32

Examination Outline Cross-Reference	Level	RO
261000 (SF9 SGTS) Standby Gas Treatment Knowledge of the physical connections and/or cause-effect relationships between STANDBY GAS TREATMENT SYSTEM and the following: K1.02 Drywell	Tier#	2
	Group#	1
	K/A #	261000 K1.02
	Rating	3.2
	Revision	0
Revision Statement:		

Question 7

A steam leak at 60% power is causing Drywell pressure to rise.

SGT B is aligned to vent the Drywell IAW Procedure 2.2.60 [Primary Containment Ventilation and Nitrogen Inerting System].

(1) According to the caution in Procedure 2.2.60 for this alignment, why is the Drywell pressure reduction required to be limited by the operator?

AND

(2) If Drywell pressure rises to 3 psig, which one of the following valves CLOSE to isolate the connection between SGT and the Drywell?

A. (1) Minimize the release of radioactivity outside PC
(2) PC-MO-306, VALVE MO 231 BYPASS VLV

B. (1) Minimize the release of radioactivity outside PC
(2) PC-AD-R-1B, CONTAINMENT EXH. TO STBY GAS TREATMENT

C. (1) Prevent Torus to Drywell vacuum breakers from opening
(2) PC-MO-306, VALVE MO 231 BYPASS VLV

D. (1) Prevent Torus to Drywell vacuum breakers from opening
(2) (2) PC-AD-R-1B, CONTAINMENT EXH. TO STBY GAS TREATMENT

Answer: C

Explanation:
SGT is connected to the DW via the DW vent line. Flow from the DW can pass through 24” inboard isolation valve PC-MO-231 or through a smaller 2” bypass line around MO-231 via PC-MO-306. Flow then passes through outboard isolation valve PC-AO-246 and then through inlet to SGT suction plenum from drywell damper PC-AD-R-1B.

Procedure 2.2.60 contains the steps for DW venting during non-EOP conditions. A caution at step 4.7 states Torus to DW vacuum breakers may open if Torus pressure is as low as 0.1 psig above DW pressure. Step 4.7.2 directs the operator to open PC-MO-306 while ensuring Torus pressure does not exceed DW pressure by > 0.1 psig, which is in order to maintain Torus to DW vacuum breakers closed.

PC-MO-231 automatically isolates on a Group 6 isolation signal. PC-AD-R-1B does not.

Distracters:
Answer A part 1 is plausible because the DW atmosphere during a steam leak would contain radioactivity, and an examinee may believe minimizing pressure reduction is to minimize the overall volume of DW atmosphere containing radioactivity released outside PC. It is also plausible because procedure 2.2.60 contains cautions related to radioactivity release when ventilating the DW to the Reactor Building exhaust plenum. It is wrong because the caution in procedure 2.2.60 related to DW venting is specific to preventing Torus to DW vacuum breakers from opening. Part 2 is correct.

Answer B part 1 is plausible and wrong for the reasons given for distractor A. Part 2 is plausible because PC-AD-R-1B is in the flow path from the drywell and because it has interlocks associated with a Group 6 isolation/initiation. An associated damper PC-AD-R-1A, which connects the DW to the Rx Bldg Vent Exh Plenum and is operated by the control switch common to PC-AD-R1B, automatically closes on a Group 6 isolation/initiation. It is wrong because PC-AD-R-1B automatically opens on a Group 6 isolation/initiation.

Answer D part 1 is correct. Part 2 is plausible and wrong for the reasons given for distractor B.

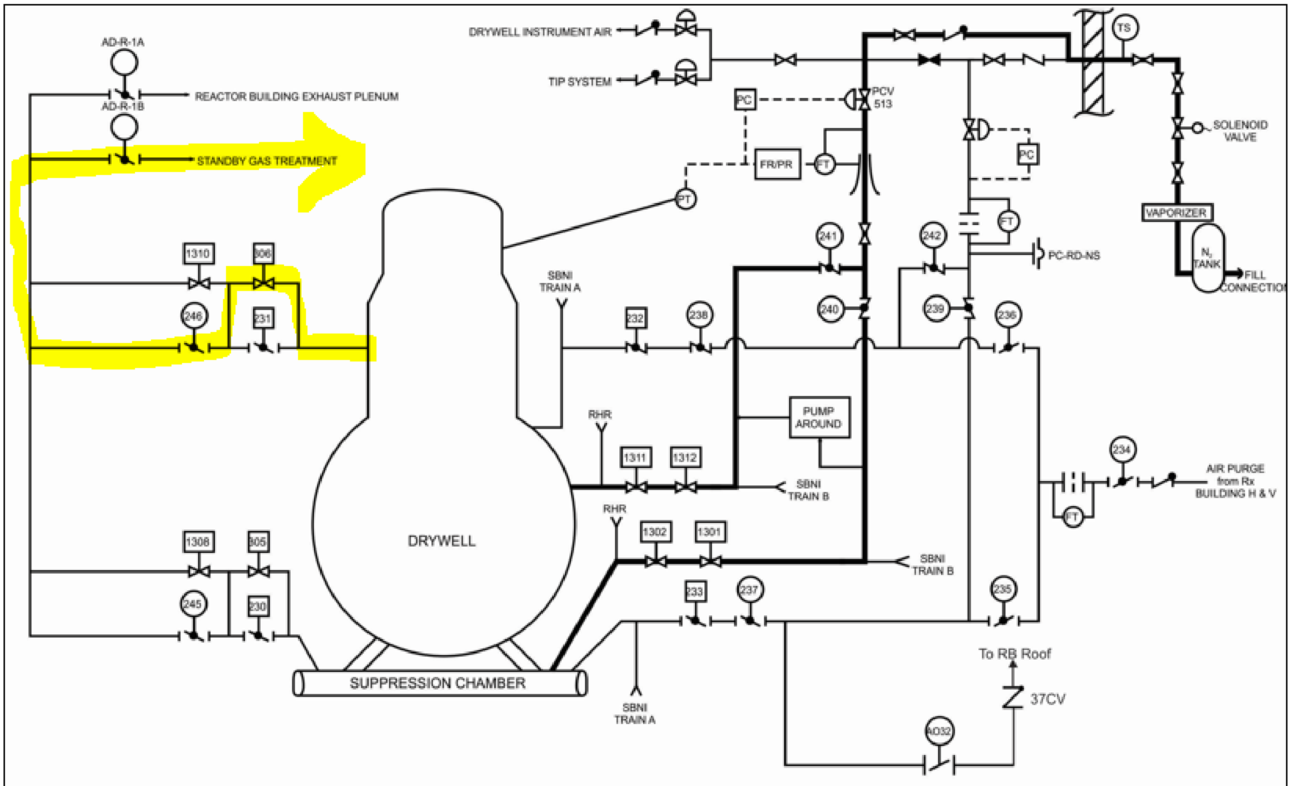
Technical References: lesson plan COR002-28-02 [Ops Standby Gas Treatment System](Rev 26), Procedure 2.2.60 [Primary Containment Ventilation and Nitrogen Inerting System](Rev 101), Procedure 2.2.73 [Standby Gas Treatment System](Rev 60)

References to be provided to applicants during exam: none

Learning Objective: COR002-28-02 LO-05b, Describe the interrelationships between SGT and the following: Primary Containment

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(7),(10)	

Level of Difficulty:	3
SRO Only Justification:	N/A
PSA Applicability:	
Top 10 Risk Significant System – Primary Containment	



PRIMARY CONTAINMENT PURGE, MAKEUP, and VENT SYSTEM

Figure 9A, Rev. 13

COR002-03-02

4. DRYWELL AND TORUS VENTING

NOTE 1 – Drywell and Torus pressures can be monitored on Panel 9-3, Panel 9-4, VBD-J, and VBD-H. If Drywell and Torus inerted and pressurized at ~ 0.25 psig, Drywell and/or Torus should be vented at ~ 0.45 psig.

NOTE 2 – Starting SGT can cause Secondary Containment pressure transient and entry into TS LCO 3.6.4.1.

NOTE 3 – Preferred SGT Subsystem should be used unless both subsystems needed for EOPs.

4.1 Ensure lineup verification requirements of ODAM DSR 3.2.7.1 completed in Procedure 6.LOG.601 or 6.LOG.602.

4.2 At VBD-K:

4.2.1 Ensure DAMPER AD-R-1A AND AD-R-1B CONTROL switch in SGT.

4.2.1.1 Check AD-R-1A closed.

4.2.1.2 Check AD-R-1B open.

4.2.2 Place SGT fan in service:

4.2.2.1 SGT A

a. Start EF-R-1E, SGT A EXHAUST FAN:

1. Check SGT-AO-249, SGT A INLET, opens.

2. Check SGT-AO-251, SGT A DISCHARGE, opens.

4.2.2.2 SGT B

a. Start EF-R-1F, SGT B EXHAUST FAN:

1. Check SGT-AO-250, SGT B INLET, opens.

2. Check SGT-AO-252, SGT B DISCHARGE, opens.

4.3 At VBD-R, ensure SGT-DPIC-546, RX BLDG/SGT DP, in MANUAL.

4.4 Ensure Parameter V displayed on SGT-DPIC-546, RX BLDG/SGT DP, by pressing D pushbutton, as necessary.

4.5 Adjust SGT-DPIC-546, RX BLDG/SGT DP, to obtain ≥ 800 scfm on SGT-FI-545, SGT DISCHARGE HEADER FLOW (VBD-K).

4.6 Ensure Annunciator K-1(2)/A-2, SGT A(B) HIGH MOISTURE, clear which ensures proper electrical air heater operation.

CAUTION – Torus to Drywell vacuum breakers may open if Torus pressure is as low as 0.1 psig above Drywell pressure.©[1]

NOTE – Steps 4.7 and 4.8 may be performed in any order or concurrently, depending on plant conditions.

4.7 At VBD-H, vent Drywell by performing following:

4.7.1 Open PC-AO-246, DW EXH OUTBD ISOL VLV.

4.7.2 While ensuring Torus pressure does not exceed Drywell pressure by > 0.1 psig, open PC-MO-306, VALVE MO 231 BYPASS VLV.©[1,2]

4.7.3 (Independent Verification) WHEN Drywell pressure ~ 0.25 psig, THEN close PC-MO-306.

Performed By: ________

Verified By: ________

4.7.4 (Independent Verification) Close PC-AO-246. Performed By: ________

Verified By: ________

4.7.5 (Independent Verification) Place control switch for PC-AO-246 to AUTO.

Performed By: ________

Verified By: ________

4.7.6 IF Torus not being vented, THEN go to Step 4.9.

13. DRYWELL AND TORUS NORMAL VENTILATION OPERATION

13.1 ESTABLISHING NORMAL VENTILATION LINEUP

CAUTION – Ventilating Drywell and/or Torus through Reactor Building exhaust plenum is only allowed when Reactor Building exhaust plenum activity ≤ 1 mr/hr.

13.1.1 Ensure Drywell and Torus have been de-inerted per Section 10 or 11.

13.1.2 Ensure Reactor in MODE 4 or 5.

NOTE – A Torus air sample may be required to determine acceptability of establishing Torus ventilation lineup.

13.1.3 Have Chemistry evaluate airborne activity level for atmosphere(s) to be ventilated.

13.1.4 Notify RP ventilation using building ventilation will be started and additional contamination controls may be required.

PROCEDURE 2.2.60	REVISION 101	PAGE 50 OF 67

PROCEDURE 2.2.60	REVISION 101	PAGE 61 OF 67

ATTACHMENT 2	INFORMATION SHEET

NOTE – PC-AO-238, PC-AO-245, and PC-AO-246 fail closed on a loss of air or power.

2.2.4 PC-AO-238, DW INLET OUTBD ISOL VLV.

2.2.5 PC-AO-245, TORUS EXH OUTBD ISOL VLV.

2.2.6 PC-AO-246, DW EXH OUTBD ISOL VLV.

2.3 Following Primary Containment isolation valves close when a Group 6 isolation occurs and associated override switch for valve is not in OVERRIDE. Valves can be opened without resetting Group 6 isolation signal by placing associated override switch to OVERRIDE and then placing valve switch to OPEN. Valves will not close if associated override switch is in OVERRIDE when Group 6 isolation signal is received.

2.3.1 PC-MO-305, VALVE MO 230 BYPASS VLV.

2.3.2 PC-MO-306, VALVE MO 231 BYPASS VLV.

2.3.3 PC-MO-233, TORUS INLET INBD ISOL VLV.

NOTE – PC-AO-237 fails closed on a loss of air or power.

2.3.4 PC-AO-237, TORUS INLET OUTBD ISOL VLV.

ATTACHMENT 3 INFORMATION SHEET

1. DISCUSSION

1.1 FUNCTION

1.1.1 SGT System provides ability to process effluent from primary and secondary containment when required to limit the discharge of radioactive material to the environs. System prevents out-leakage from secondary containment during periods of primary and/or secondary containment isolation by holding it at a sub atmospheric pressure of $\leq$ -0.25" wg. System is also used to perform leak tests on secondary containment.

1.2 OPERATING CHARACTERISTICS

1.2.1 SGT System consists of two 100% capacity, identical parallel air filtration subsystems, completely enclosed within a Class 1 structure.

1.2.2 System is designed to take suction from Reactor Building main exhaust (normal), Primary Containment, HPCI System Gland Seal Exhauster, and SGT Room.

1.2.2.1 When HPCI System Gland Seal Exhauster is running, HPCI-AO-275 opens to admit exhauster discharge to SGT System. Valve fails closed on a loss of air or control power.

1.2.2.2 Suction damper from Primary Containment to SGT System, PC-AD-R-1B, opens automatically when a Group 6 isolation signal is received. Suction damper from Primary Containment to Reactor Building Exhaust Plenum, PC-AD-R-1A, automatically closes when a Group 6 isolation signal is received. PC-AD-R-1A fails closed on a loss of air or control power. PC-AD-R-1B fails open on a loss of air or control power.

1.2.2.3 Air Operated Room Air Inlet Valve SGT-AO-270 (SGT-AO-271), SGT A (B) DILUTION AIR, opens when a Group 6 isolation signal is received. Valve fails open on a loss of air or control power.

Examination Outline Cross-Reference	Level	RO
262001 (SF6 AC) AC Electrical Distribution Knowledge of electrical power supplies to the following: K2.01 Off-site sources of power	Tier#	2
	Group#	1
	K/A #	262001 K2.01
	Rating	3.3
	Revision	0
Revision Statement:		

Question 8

What is the normal power source to the Emergency Service Station Transformer?

A. OPPD line via the T6 transformer

B. Auburn line via the T7 transformer

C. 161 KV substation via the T7 transformer

D. 161 KV substation via the T6 transformer

Answer: D

Explanation:
During normal station operation, the Emergency Service Station Transformer (ESST) is energized by the 69 kV transmission line from the 69 kV Bay of the 161 kV Substation via Transformer T6 through Air Break Switch 5298. The Emergency Transformer supply can be aligned to either the Cooper 161 kV System via Transformer T6 or to the OPPD 69 kV line.

Distracters:
Answer A is plausible because the 69 KV OPPD line can feed the ESST. It is incorrect because the OPPD line does not connect with the ESST via the T6 transformer.

Answer B is plausible because the 161KV Auburn line does supply the ESST, just not directly. It is wrong because the Auburn line connects with the 161 kV Substation. From the 161 kV Substation the power must go through the 69 kV Bay and the T6 transformer to connect with the ESST. The Auburn line does not connect to the ESST via the T7 transformer.

Answer C is plausible because the 161KV substation supplies the ESST via a step down transformer. It is wrong because the ESST is supplied via step down transformer T6, not T7.		
Technical References: procedure 2.2.17 [Emergency Station Service Transformer](Rev 73), TS 3.8.1 Bases		
References to be provided to applicants during exam: none		
Learning Objective: COR001-01-01 Obj LO-7a, State the electrical power supplies to the following: Off-Site Sources of Power		
Question Source:	Bank #	4/2015 ILT NRC Q#44
(note changes; attach parent)	Modified Bank #	
	New	
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(7)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA Applicability:		
Top 10 Risk Significant System – Emergency AC Power		

4/2015 ILT NRC Q#44

262001 AC Electrical Distribution – Knowledge of electrical power supplies to the following: (CFR: 41.7)
K2.01 Off-site sources of power.

Question: 44

What is the normal power source to the Emergency Service Station Transformer?

A. The OPPD line via the T6 transformer.

B. The Auburn line via the T7 transformer.

C. The 161 KV substation via the T6 transformer.

D. The 161 KV substation via the T7 transformer.

Answer:
C. The 161 KV substation via the T6 transformer.

ATTACHMENT 1 INFORMATION SHEET

1. DISCUSSION

1.1 FUNCTION

1.1.1 Emergency Transformer is secondary off-site AC power source to essential station loads. As such, it supplies 4160V Switchgear 1F and/or 1G in the event that Normal Transformer and Startup Transformer are not available for service. Use of Emergency Transformer also allows portions of 345 kV System to be removed from service for inspection, testing, and maintenance.

1.2 OPERATING CHARACTERISTICS

1.2.1 The 69 kV/4160V Emergency Transformer consists of 69 kV/4160V Transformer, gang operated AIR BREAK Switch 5298, Breaker 1FS, and Breaker 1GS.

1.2.1.1 Emergency Transformer MODS allows isolation of Emergency Transformer during SDG operation. SDG MODS allows isolation of Supplemental Diesel Generator from AC Distribution System.

1.2.2 During normal station operation, Emergency Transformer is energized by 69 kV transmission line from 69 kV Bay of 161 kV Substation through Air Break Switch 5298. Emergency Transformer MODS is maintained closed, with SDG MODS maintained open to isolate SDG. Emergency Transformer is maintained in a ready state for emergency operation with Breakers 1FS and 1GS racked in and open. Breakers 1FS and 1GS have automatic closing features to supply power to 4160V Buses 1F and 1G.

1.2.2.1 In 69 kV Bay, Emergency Transformer supply can be aligned to either Cooper 161 kV System via Transformer T6 or to OPPD 69 kV line.

a. Emergency Transformer operability is supported during transfer of its power source between Transformer T6 and 69 kV OPPD Line.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources - Operating

BASES

BACKGROUND

The unit AC Sources for the Class 1E AC Electrical Power Distribution System consist of the offsite power sources (preferred power sources, normal and alternates), and the onsite standby power sources (diesel generators (DGs)). As summarized in the USAR, (Ref. 1), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The Class 1E AC distribution system is divided into redundant load groups, so loss of any one group does not prevent the minimum safety functions from being performed. Each load group has connections to two qualified offsite power supplies and a single DG.

The offsite power sources are a startup station service transformer (SSST) which connects to the 161 kV switchyard and a separate emergency station service transformer (ESST) energized by a 69 kV line. The 161 kV switchyard is connected to one 161 kV line which terminates in a switchyard near Auburn, Nebraska, two 345/161 kV, 300 MVA auto-transformers (T2 and T5) which connect to the 345 kV switchyard, and one 161/69 kV 56MVA auto-transformer (T6) which can connect to the 69 kV system and serve as a source for the ESST. Either T2 or T5 is sufficient to power the 161/69 kV system. The 345 kV switchyard has five lines which terminate in switchyards near Tarkio, Missouri; Hallam, Nebraska; St. Joseph, Missouri; Fairport, Missouri; and Nebraska City, Nebraska. The ESST is fed by either a 69 kV line which is part of a subtransmission grid of the Omaha Public Power District, or by the 161/69 kV auto-transformer (T6). If the normal station service transformer (NSST) (powered by the main generator) is lost, the SSST, which is normally energized, will automatically energize 4160 volt buses 1A and 1B, as well as their connected loads, including critical buses 1F & 1G. If the SSST fails to energize the critical buses, the ESST, which is normally energized, will automatically energize both critical buses. If the ESST were also to fail, the emergency diesel generators would automatically energize their respective buses. A detailed description of the offsite power network and circuits to the onsite Class 1E critical buses is found in the USAR, Sections VIII-2.0 and VIII-3.0 (Ref. 2).

Examination Outline Cross-Reference	Level	RO
400000 (SF8 CCS) Component Cooling Water Knowledge of electrical power supplies to the following: K2.02 CCW valves	Tier#	2
	Group#	1
	K/A #	400000 K2.02
	Rating	2.9
	Revision	0
Revision Statement:		

Question 9

What is the normal power supply to REC-MO-713 [REC HX B Outlet Valve]?

A. MCC-C

B. MCC-M

C. MCC-R

D. MCC-RB

Answer: D

Explanation:
Modified question by changing the subject valve in the stem, making the correct answer different than in the original question.

Procedure 2.2A.REC.DIV3 lists MCC-RB breaker 4B as the power supply to MO-713.

Distracters:
Answer A is plausible because other MOVs, such as MC-MO-1 [SJAE Cond A Inlet], are powered from MCC-C. It is wrong because MO-713 is powered from MCC-RB.

Answer B is plausible because MCC-M is also powered from 480B Bus 1F and other loads in the Reactor Building are powered from MCC-M, including REC-TIC-451A. It is wrong because MO-713 is powered from MCC-RB.

Answer C is plausible because MCC-R powers REC-MO-700 [Non-Critical Header Supply]. It is wrong because MO-713 is powered from MCC-RB.

Technical References: procedure 2.2A.REC.DIV3 [Reactor Equipment Cooling Water System Common Divisional Component Checklist](Rev 3), Procedure 5.3AC480 [480 VAC Bus Failure](Rev 55), procedure 2.2A_480.RX [480 VAC Reactor Building Breaker Checklist](Rev 22)		
References to be provided to applicants during exam: none		
Learning Objective: COR002-19-02 Obj LO-2a, State the electrical power supplies to the following REC components: Valve Motors		
Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	9/2018 ILT NRC Q#53
	New	
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(4)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA Applicability		
N/A		

9/2018 ILT NRC Q#53

Examination Outline Cross-Reference	Level	RO
400000 Component Cooling Water K2.02 Knowledge of electrical power supplies to the following: (CFR: 41.7) CCW valves	Tier#	2
	Group#	1
	K/A #	400000 K2.02
	Rating	2.9
	Revision	1
Revision Statement: Rev 1 – Replaced distractor D with another MCC per CE comments		

Question 53

What is the normal power supply to REC-MO-700 [Non-Critical Header Supply]?

A. MCC-C

B. MCC-M

C. MCC-R

D. MCC-RB

Answer: C

ATTACHMENT 2 POWER SUPPLY CHECKLIST

DESCRIPTION	POWER SUPPLY	NORMAL POSITION	PERFORMED BY	VERIFIED BY	COMMENTS
REC-MO-1329	EE-MCC-Q(1C)	ON			
REC-MO-721	EE-MCC-Q(7C)	ON			
REC-MO-700	EE-MCC-R(7C)	ON			
REC-MO-702	EE-MCC-R(7D)	ON			
REC-MO-709	EE-MCC-R(8A)	ON			
REC-MO-695	EE-MCC-R(8B)	ON			
REC-MO-694	EE-MCC-R(8C)	ON			
REC-MO-713	EE-MCC-RB(4B)	ON			
REC-MO-712	EE-MCC-Y(4C)	ON			

ATTACHMENT 1 REACTOR BUILDING BREAKER CHECKLIST DIVISION 1

MCC-M – (R-958-N) FED FROM 480V SWITCHGEAR 1F

BREAKER	DESCRIPTION	NORMAL POSITION	PERFORMED BY	VERIFIED BY	COMMENTS
EE-MCC-M(1AL)	FEED TO LTG. PNLS LPR2F & LPR3F	ON			
EE-MCC-M(1AR)	BLDG-HST-H12 RWCU FDEM HOIST 5 TON	ON			
EE-MCC-M(1B)	SPARE	OFF			
EE-MCC-M(1CL)	WELDING RECEPTACLES COL K9.3 AND M11.7	ON			
EE-MCC-M(1CR)	FEEDER TO SERVICE PLATFORM	ON			
EE-MCC-M(1D)	SPARE	OFF			
EE-MCC-M(1E)	RWCU-P-PP RWCU PRECOAT PUMP	ON			
EE-MCC-M(1FL)	EE-UPS-233MV PC-233MV UPS	ON			
EE-MCC-M(2AL)	MOTOR SPACE HTR PANEL SPR3	ON			

ATTACHMENT 2 480V BUS 1A - MAJOR LOADS

LOADS	NOTES
MCC-B	
MCC-E	
Normal and Startup Transformer Coolers	Fans should Transfer to MCC-G.
HV-T-1C Supply Fan A	
Generator Bus Duct Fan 1A	
Turbine Building Exhaust Fans A and B	
Hydrogen Side Seal Oil Pump	
VAC Priming Pump A	
Generator Loop Seal Vapor Extractor	
CO_2 HEX Electric Vaporizer	
CO_2 Storage Tank Cond Unit Compressor	
Motor Space Heater Panel SPTG1	Causes loss of power to ground indicating lights for 480V Bus 1A, MCC-B, E, A, C, D. Loss of Annunciator Cabinet 2 fan.
Lighting Panel LPTG8	Loss of Annunciator Cabinets 3 and 4 fans.
Sewage Treatment Building	
VAC Priming Pump A Recirc Seal Pump	
Air Side Seal Oil Pump	
MCC-C	
MC-MO-1 SJAE Cond A Inlet	
MC-MO-2 SJAE Cond A Outlet	
RFPT A Lube Oil Pump A1	
RFPT A Lube Oil Transfer Pump A	
RFPT A Turning Gear	
RFPT B Lube Oil Pump B1	
MC-MO-26 Startup Bypass	
RF-MO-29 RFP A Discharge	Will not auto close on Main Turbine trip.
MCC-D	
RF-MO-31 RFP A Startup Valve Outlet	
RF-MO-32 RFP A Startup Valve Inlet	
AR-MO-161 SJAE A Air Outlet	
MS-MO-IMV3 Gland Seal Steam Supply	
MC-MO-301, 302, 303 CBP Discharge Valves	

ATTACHMENT 9 480V BUS 1F - MAJOR LOADS

LOADS	NOTES
CDP-1A	Causes loss of CCP-1A and CCP-2A. PC-AO-243, TORUS VAC RELIEF, fails open. RR-AO-741, INBD ISOL VLV, fails closed. SA-PCV-609, SERVICE AIR SYSTEM ISOLATION, fails closed. Cannot reset Group 6 Isolation until CCP-1A restored.
250 VDC Battery Charger 1A	
125 VDC Battery Charger 1C	
SW-MO-36 Loop Crosstie Valve	Effects Service Water OPERABILITY.
Control Room AC Unit 1A Compressor	
LPCEM1 Control Room Emergency Lighting	
Lighting Panel CBPP	
MCC-M	
Lighting Panels LPR2F and LPR3F	Causes loss of power to REC-TIC-451A.
RRMG Set A Lube Oil Pumps	AC pumps only. RRMG Set trips at bearing oil pressure of 28 psig + 6 seconds.
Motor Space Heater Panel SPR3	
Power Panel MPR1	
RRMG Exh Fan EF-R-1C	
RRMG-A Scoop Tube Positioner	
Reactor Building Supply Fan SF-R-1A-A	
Reactor Building Exhaust Fan EF-R-1A	
MCC-N	
Drywell Sump Pump 1G2	
Reactor Building Sump Pump 1E2	
Reactor Building Auxiliary Condensate Booster Pump	
Lighting Panel LPR1F	Loss of Annunciator Cabinet 9 fan.
Motor Space Heater Panel SPR1	Loss of Annunciator Cabinet 10 fan.
Reactor Building Exhaust Booster Fan A	
Off-Gas Building Power Panel PPGB1	
Drywell Sump Pump 1F2	

Examination Outline Cross-Reference	**Level**	RO
206000 (SF2, SF4 HPCIS) High-Pressure Coolant Injection 2.4.31 Knowledge of annunciator alarms, indications, or response procedures.	**Tier#**	2
	Group#	1
	K/A #	206000 G2.4.31
	Rating	4.2
	Revision	
Revision Statement:		

Question 10

HPCI is in standby when the following annunciators are received:

HPCI TURBINE TRIP	PANEL/WINDOW: 9-3-2/B-1
HPCI-MO-15/16 NOT FULL OPEN	PANEL/WINDOW: 9-3-2/B-2

HPCI Inboard and Outboard Isolation Valves MO-15 AND MO-16 go closed.

The amber AUTO ISOL SIG light on Panel 9-3 is **NOT** lit.

What caused these indications?

A. HPCI Low Steam Line Pressure isolation has occurred

B. HPCI Steam Line High Steam Flow isolation has occurred

C. HPCI MANUAL ISOLATION push button was depressed

D. HPCI Steam Line Space High Temperature isolation has occurred

Answer: A
Explanation: Conditions given in the stem indicated a HPCI isolation has occurred. The HPCI amber AUTO ISOL SIG light indicates the isolation logic has sealed in, requiring the reset push button to be depressed after the isolation condition has cleared in order to reset the logic and allow the isolation valves to be recovered. Only the low steam

supply pressure isolation signal does not cause HPCI isolation logic to seal in and will auto reset when the condition clears. For this reason, a Low Steam Line Pressure condition will not illuminate the Amber AUTO ISOL SIG light and will not actuate the HPCI Isolation annunciator 9-3-2/A-2, but it causes all other isolation functions to occur.

Distracters:

Answer B is plausible because HPCI steam line high steam flow (high D/P) is a HPCI isolation signal. It is wrong because the Amber AUTO ISOL SIG light and annunciator 9-3-2/A-2 [HPCI Isol Sig A/B Initiated] would also be on.

Answer C is plausible because an isolation is present but the AUTO ISOL SIG amber light is off. It is wrong because the HPCI MANUAL ISOLATION push button only causes an isolation when a HPCI initiation signal is present.

Answer D is plausible because HPCI Steam Line Space High Temperature is an isolation signal. It is wrong for the same reason stated for distractor B.

Technical References: procedure 2.2.33 [High Pressure Coolant Injection System](Rev 84), Alarm Card 9-3-2/B-1 [HPCI TURBINE TRIP](Rev 34), Alarm Card 9-3-2/A-2 [HPCI ISOL SIG A/B INITIATED](Rev 34)

References to be provided to applicants during exam: none

Learning Objective: COR002-11-02 Obj LO-8b, Describe the HPCI design features and/or interlocks that provide for the following: System isolation

Question Source:	Bank #	5136
(note changes; attach parent)	Modified Bank #	
	New	
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(7)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	

PSA Applicability;

Top 10 Risk Significant System - HPCI

SETPOINT	CIC	9-3-2/B-1
(1600) HPCI TURBINE TRIPPED at HPCI turbine stop valve closed and 15 second time delay from time HPCI-MO-14 was not full closed has timed out	HPCI-REL-K13 and HPCI-REL-K14	

PROBABLE CAUSES

- High RPV water level.
- Manual trip.
- Low pump suction pressure.
- High turbine exhaust pressure.
- HPCI turbine overspeed.
- Group 4 isolation.
- Low steam pressure isolation.

REFERENCES

- Technical Specifications Table 3.3.5.1-1, Function 3c.
- Technical Specifications Table 3.3.6.1-1, Functions 3a through 3d.
- Technical Specifications LCO 3.5.1, ECCS - Operating.
- Technical Requirements Manual Table T3.3.2-1, Functions 4a through 4g.

ATTACHMENT 1 INFORMATION SHEET

2. INTERLOCKS AND SETPOINTS

2.1 INTERLOCKS

2.1.1 MOTOR OPERATED VALVES

2.1.1.1 HPCI-MO-15, STM SUPP INBD ISOL VLV

a. Closes on a low steam supply pressure (≥ 107 psig) or HPCI System isolation signal and cannot be re-opened until the isolation signal or low steam supply pressure signal is cleared.

2.1.1.2 HPCI-MO-16 STM SUPP OUTBD ISOL VLV

a. Closes on low steam supply pressure (≥ 107 psig) or HPCI System isolation signal and cannot be re-opened until the isolation signal or low steam supply pressure signal is cleared.

2.1.1.3 HPCI-MO-14, STM TO TURB VLV

a. Opens on either high drywell pressure or low reactor water level.

b. Closes on a high reactor water level ≤ 54.0".

2.1.1.4 HPCI-MO-17, ECST PUMP SUCT VLV

a. Opens on either high drywell pressure or low reactor water level, if HPCI-MO-58, TORUS PUMP SUCT VLV, is not fully open.

b. Closes when HPCI-MO-58 is fully open (overrides the open signal from either high drywell pressure or low reactor water level).

2.2.6 The reactor high water level signal is a seal in signal.

2.2.6.1 With high water level signal sealed in and water level lowers to or below the initiation setpoint, the HPCI System will automatically restart.

2.2.6.2 The high water level trip signal may be manually reset if:

a. Level goes below the high level trip point; and

b. REACTOR HI WTR LEVEL SIGNAL RESET pushbutton is depressed.

2.2.7 A mechanical/hydraulic overspeed trip occurs at 125% of rated speed. This trip is time dependent and resets upon loss of hydraulic pressure to the trip mechanism. The amount of time is adjusted to correspond to the time it takes the turbine to coast down to a speed of about 3000 rpm and then returns to normal operation. The speed at which the turbine is spinning when the reset occurs is greatly dependent upon the load on the pump at the time of the overspeed trip.

2.2.8 The HPCI ISO SIGNAL A/B INITIATED signal (Group 4 Isolation) is generated upon receipt of any of the following:

2.2.8.1 Steam line space high temperature at ≤ 195°F.

2.2.8.2 Steam supply line high differential pressure at ≤ 250% flow.

2.2.9 Steam line space high temperature and high differential pressure in the steam line isolation signals are seal in type and must be manually reset by depressing both AUTO ISOLATION SIG 23A-S18A and AUTO ISOL SIGNAL 23A-S18B pushbuttons.

2.2.10 Upon receipt of Annunciator 9-3-2/A-2, HPCI ISOL SIG A/B INITIATED, signal, the following automatically occurs:

2.2.10.1 The following valves close:

a. HPCI-MO-15, STM SUPP INBD ISOL VLV, if open.

b. HPCI-MO-16, STM SUPP OUTBD ISOL VLV, if open.

c. HPCI-MO-58, TORUS PUMP SUCT VLV, if open.

d. HPCI-AO-70, TURB EXH LINE DR POT TO GLD SEAL CNDSR VLV, if open.

e. HPCI-AO-71, TURB EXH LINE DR POT TO GLD SEAL CNDSR VLV, if open.

2.2.10.2 HPCI turbine trips.

2.2.10.3 AUTO ISOL SIGNAL amber indicating light turns on.

2.2.10.4 GROUP 4, CHANNEL A and CHANNEL B isolation white indicating lights (Panel 9-5) turn off.

2.2.11 The HPCI System may be manually isolated by depressing INITIATION SIGNAL ONLY MANUAL ISOLATION pushbutton only when an initiation signal is present.

3. REFERENCES

3.1 TECHNICAL SPECIFICATIONS

3.1.1 LCO 3.3.5.1, Emergency Core Cooling System (ECCS) Instrumentation.

3.1.2 LCO 3.3.6.1, Primary Containment Isolation Instrumentation.

3.1.3 LCO 3.5.1, ECCS - Operating.

3.1.4 LCO 3.6.2.1, Suppression Pool Average Temperature.

3.1.5 LCO 3.6.2.2, Suppression Pool Water Level.

SETPOINT	CIC	9-3-2/A-2
1. (1618) HPCI ISOLATION CHANNEL B TRIP 2. (1619) HPCI ISOLATION CHANNEL A TRIP	1. HPCI-REL-K34 2. HPCI-REL-K44	

PROBABLE CAUSES

- High steam line area space temperature caused by steam leak or high environment temperature.
- High differential pressure caused by steam line break.
- Manual isolation.

REFERENCES

- Technical Specifications Table 3.3.6.1-1, Functions 3a through 3d.
- Technical Specifications LCO 3.5.1, ECCS - Operating.
- General Operating Procedure 2.1.22, Recovering From a Group Isolation.

Section Break (Next Page)

Examination Outline Cross-Reference	**Level**	RO
215004 (SF7 SRMS) Source-Range Monitor Knowledge of the effect that a loss or malfunction of the SOURCE RANGE MONITOR (SRM) SYSTEM will have on following: K3.04 Reactor power and indication	**Tier#**	2
	Group#	1
	K/A #	215004 K3.04
	Rating	3.7
	Revision	0
Revision Statement:		

Question 11

IRMs are on Range 7 during startup.

SRM SHORTING LINK SWITCHES are in their normal positions for startup.

The following alarm is received relative to SRM C:

SRM UPSCALE/INOP	PANEL/WINDOW: 9-5-1/F-7

SRM C back panel indication is:

(1) What is the cause of the above alarm? **(Assume MAXIMUM allowed TRM setpoint.)**

AND

(2) What is the status of the reactor?

A. (1) SRM Inop
   (2) Operating

B. (1) SRM Inop

(2) Scrammed

C. (1) SRM Upscale
(2) Operating

D. (1) SRM Upscale
(2) Scrammed

Answer: A		
Explanation: The SRM Upscale/Inop alarm combined with the given SRM C reading of 5E4 cps indicates a SRM Inop condition caused the alarm, not upscale since count rate is below 1E5. With IRMs on range 7, an SRM inop produces a control rod block, not automatically bypassed until IRMs are on range 8 or the Reactor Mode Switch is in RUN during a plant start up. The normal position of SRM SHORTING LINK SWITCHES is CLOSE. With SRM shorting link switches in CLOSE, SRM trip signals are bypassed within RPS, so only a rod block occurs with SRM C Inop.		
Distracters: Answer B part 1 is correct. Part 2 is plausible because a SRM hi-hi flux trip on any channel would result in a full scram if shorting link switches were in OPEN. When shorting links are open, SRM hi-hi flux trip signals result in non-coincident RPS trip signals. It is wrong because SRM shorting link switches are normally in CLOSE, so SRM trip signals are bypassed within RPS, so only a rod block occurs. Answer C part 1 is plausible because the alarm is common to a SRM Upscale condition. It is wrong because the maximum allowed value for SRM upscale is 1E5 cps, but SRM C is below the setpoint at 5E4 cps. Part 2 is correct. Answer D part 1 is plausible and wrong for the reason given for distractor C. Part 2 is plausible and wrong for the reason given for distractor B.		
Technical References: TRM 3.3.1 [Control Rod Block Instrumentation], Alarm Card 9-5-1/F-7 [SRM Upscale/Inop](Rev 36), procedure 4.1.4 [Source Range Monitor Instrumentation](Rev 24)		
References to be provided to applicants during exam: none		
Learning Objective: COR002-30-02 Obj LO 7d, Given a specific SRM system malfunction, determine the effect on the following: Reactor power indication		
Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	

	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(6)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA Applicability:		
N/A		

SETPOINT	CIC	9-5-1/F-7
(2355) 4.0 x 10^4 cps (TRM ≤ 1 x 10^5 cps) or inop due to:	NMS-NAM-40A through NMS-NAM-40D	

1. High voltage low
2. Module unplugged
3. MODE switch not in operate
4. Loss of negative supply voltage

PROBABLE CAUSES

- High alarm during reactor startup.

REFERENCES

- Technical Requirements Manual TLCO 3.3.1, Control Rod Block Instrumentation.

Control Rod Block Instrumentation
T 3.3.1

Table T3.3.1-1 (Page 1 of 3)
Control Rod Block Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	ACCEPTANCE LIMITS
1. SRM				
a. Detector Not Full In	2 (a), (b)	1 per circuit loop	TSR 3.3.1.3 TSR 3.3.1.8	NA
	5	(c)	TSR 3.3.1.3 TSR 3.3.1.8	NA
b. Upscale	2 (a)	1 per circuit loop	TSR 3.3.1.1 TSR 3.3.1.3 TSR 3.3.1.4 TSR 3.3.1.8	$\leq 1 \times 10^5$ cps
	5	(c)	TSR 3.3.1.3 TSR 3.3.1.4 TSR 3.3.1.8	$\leq 1 \times 10^5$ cps
c. Inoperative	2 (a)	1 per circuit loop	TSR 3.3.1.3 TSR 3.3.1.4	NA
	5	(c)	TSR 3.3.1.3 TSR 3.3.1.4	NA
d. Downscale	2 (a)	1 per circuit loop	TSR 3.3.1.1 TSR 3.3.1.3 TSR 3.3.1.4 TSR 3.3.1.8	≥ 3 cps
	5	(c)	TSR 3.3.1.3 TSR 3.3.1.4 TSR 3.3.1.8	≥ 3 cps

(continued)

(a) With IRMs on Range 2 or below.

(b) With SRM count rate < 100 cps.

(c) As required by Technical Specifications LCO 3.3.1.2.

1. PURPOSE

   1.1 Operate Source Range Monitoring (SRM) System.

2. PRECAUTIONS AND LIMITATIONS

   2.1 Reactor scram occurs when single High-High neutron monitor channel trips with all four RPS shorting link switches open.

3. PREREQUISITES

   3.1 **ENSURE** Procedure 4.1.1A complete to support system operation.

Examination Outline Cross-Reference	Level	RO
262002 (SF6 UPS) Uninterruptable Power Supply (AC/DC) Knowledge of the effect that a loss or malfunction of the following will have on the UNINTERRUPTABLE POWER SUPPLY (A.C./D.C.): K6.03 Static inverter	**Tier#**	2
	Group#	1
	K/A #	262002 K6.03
	Rating	2.7
	Revision	
Revision Statement:		

Question 12

The plant is at 100% power.

PMIS UPS **inverter** fails due to overcurrent.

The PMIS UPS Main Panel is now __________ .

A. de-energized

B. energized via MDP-1

C. energized via MDP-2

D. energized via MCC-L

Answer: B

Explanation:
The PMIS-UPS provides an uninterruptible source of 208 VAC power to the Plant Management Information System (plant computer). PMIS-UPS consists of a battery charger, battery, inverter, and the PMIS UPS Main panel. Power to PMIS UPS Main panel is normally supplied from the 12.5 kV distribution system at the multi-purpose facility (MPF) panel MDP-2 through an automatic transfer switch to a battery charger. The battery charger's DC output is sent to a 75 kVA inverter and supplies a trickle charge to the battery. The inverter converts the DC voltage to AC and supplies PMIS UPS main panel. An alternate source of power from MCC-L is also provided. If the normal supply is lost, the transfer switch will shift to MCC-L. The 75 kVA static switch will transfer to MDP-1 on inverter failure, which could be caused by low battery/DC supply voltage, or an overcurrent condition on the inverter. MDP-1 may also be put on line manually with a manual bypass switch. This allows PMIS UPS Main panel to remain energized while de-energizing the PMIS-UPS inverter cabinet for maintenance.

Distracters:
Answer A is plausible because MDP-1 also has a bypass switch that must be operated manually. The examinee may believe the transfer to MDP-1 must be performed manually if the inverter fails. It is wrong because the 75 kVA static switch will automatically transfer to MDP-1 on inverter failure.

Answer C is plausible because MDP-2 can ultimately supply power to the PMIS UPS main panel. It is wrong because MDP-2 can only supply power to the PMIS UPS Main Panel via the inverter, but the inverter has failed.

Answer D is plausible because MCC-L can ultimately supply power to the PMIS UPS main panel, and there is an automatic transfer to the MCC-L supply if the normal supply, MDP-2 is lost. It is wrong because MCC-L can only supply power to the PMIS UPS Main Panel via the inverter, but the inverter has failed.

Technical References: Lesson plan COR001-01-01 [Ops AC Electrical Distribution](Rev 50)

References to be provided to applicants during exam: none

Learning Objective: COR001-01-01 Obj LO-6d, Describe the interrelationship between the AC Electrical Distribution System and the following: PMIS UPS; 8e, Predict the consequences of the following on plant operation: PMIS/UPS Inverter Failure

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(4)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	

PSA Applicability:
N/A

H. Plant Management Information System (PMIS) Uninterruptible Power Supply (UPS)

1. The PMIS-UPS provides an uninterruptible source of 208 VAC power to the Plant Management Information System (plant computer).

2. The PMIS-UPS consists of a battery charger, battery, inverter, and the PMIS UPS Main panel.

3. Power supplies

a. Power to PMIS UPS Main panel is normally supplied from the 12.5 kV distribution system at the multi-purpose facility (MPF) panel MDP-2 through an automatic transfer switch to a battery charger. The battery charger's DC output is sent to a 75 kVA inverter and supplies a trickle charge to the battery. The inverter converts the DC voltage to AC and supplies PMIS UPS main panel.

b. An alternate source of power from MCC-L is also provided. If the normal supply is lost, the transfer switch will shift to MCC-L.

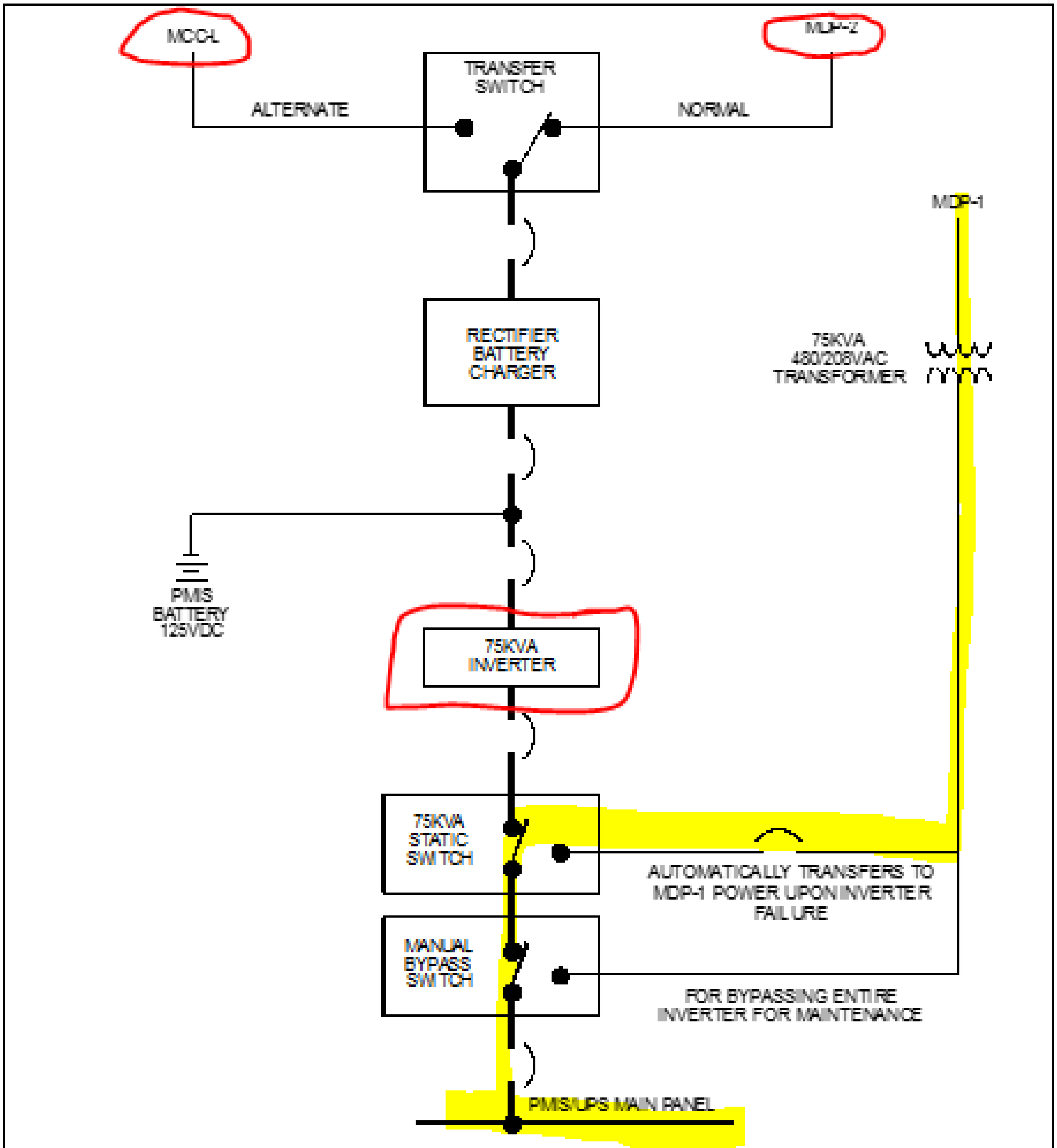
c. If power is lost to MCC-L, the feeder to the PMIS-UPS will remain locked out for 15 minutes following re-energization of MCC-L.

d. If MDP-2 were lost during the 15 minute period that MCC-L is unavailable, the PMIS 125 VDC battery will assume the load.

e. The 75 kVA static switch will transfer to MDP-1 on inverter failure, which could be caused by low battery/DC supply voltage, or an overcurrent condition on the inverter.

f. MDP-1 may also be put on line manually with a manual bypass switch. This allows PMIS UPS Main panel to remain energized while de-energizing the PMIS-UPS inverter cabinet for maintenance.

4. PMIS UPS main panel supplies power to the plant (PMIS) computer components only.



PLANT MANAGEMENT INFORMATION SYSTEM (PMIS)
UNINTERRUPTIBLE POWER SUPPLY (UPS)

Figure 8, Rev. 9

COR001-01

Examination Outline Cross-Reference	Level	RO
215003 (SF7 IRM) Intermediate-Range Monitor Knowledge of the operational implications of the following concepts as they apply to INTERMEDIATE RANGE MONITOR (IRM) SYSTEM: K5.03 Changing detector position	Tier#	2
	Group#	1
	K/A #	215003 K5.03
	Rating	3.0
	Revision	0
Revision Statement:		

Question 13

The plant is in Mode 2.

All IRMs are fully inserted AND are reading 65 on range 4.

Which one of the following describes the FIRST effect that would occur if IRM C were to be withdrawn under these conditions?

A. ONLY a Rod Withdrawal Block when IRM C detector reaches NOT fully inserted position

B. ONLY a Rod Withdrawal Block when IRM C detector reaches fully withdrawn position

C. Rod Withdrawal Block <u>AND</u> RPS Div 1 half scram when IRM C detector reaches NOT fully inserted position

D. Rod Withdrawal Block <u>AND</u> RPS Div 1 half scram when IRM C detector reaches rate reaches fully withdrawn position

Answer: A
Explanation: With the plant in Mode 2, the Reactor Mode Switch is in STARTUP. With the Reactor Mode Switch **<u>not</u>** in RUN, a control withdrawal rod block is generated when an IRM is not fully inserted, unless it is bypassed.
Distracters: Answer B is plausible because IRM downscale generates a rod withdrawal block with the Reactor Mode Switch in STARTUP and because IRM fully withdrawn position actuates a status light on panel 9-5 just as does fully inserted position. SRMs can be withdrawn without generating a detector not fully inserted rod withdrawal block when

IRMs are on range 3 or above. The examinee who confuses IRM interlocks with SRM interlocks or IRM fully withdrawn position with fully inserted position may choose this answer. It is wrong because IRMs generate a rod withdrawal block in Mode 2 if any detector is not fully inserted, regardless of selected range.

Answer C is plausible because a rod withdrawal block would be generated due to IRM C detector not fully inserted. It is also plausible because some IRM C signals, INOP and Upscale Hi-Hi, would cause a half scram. The examinee who believes a half scram would be generated would choose this answer. It is wrong because IRM downscale is only a rod withdrawal block signal.

Answer D is plausible for the same reason stated for distractor A and because some IRM C signals, INOP and Upscale Hi-Hi, would cause a Div 1 RPS half scram. The examinee who confuses IRM interlocks with RMCS with those for RPS, believing an IRM downscale generates a half scram, may choose this answer. It is wrong because IRM downscale is only a rod withdrawal block signal.

Technical References: Lesson plan COR002-12-02 [Intermediate Range Monitoring System](Rev 16), Procedure 4.1.2 [Intermediate Range Monitoring System](Rev 24), procedure 4.1.1 [Source Range Monitoring System](Rev 24), TS 3.3.1.1 [RPS Instrumentation, TRM 3.3.1 [Control Rod Block Instrumentation]

References to be provided to applicants during exam: none

Learning Objective: COR002-12-02 Obj LO-5a, Describe the IRM system design features and/or interlocks that provide the following: Rod withdrawal blocks; 5e, Changing detector position

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(6)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	

PSA Applicability:
N/A

Lesson Number: COR002-12-02	Revision: 16

LO-05a, b, e; 7b; 9a, b

TABLE 1

IRM TRIPS

ROD BLOCK TRIPS

Trip	Setpoint	Bypassed
IRM DOWNSCALE	≥ 2.5/125 of scale	Reactor Mode switch in RUN or IRM on Range 1.
IRM HIGH FLUX	≤ 108/125 of scale	Reactor Mode switch in RUN.
IRM INOPERATIVE	1) Module unplugged 2) High voltage low 3) IRM Mode switch not in OPERATE 4) Loss of negative supply voltage	Reactor Mode switch in RUN.
IRM DETECTOR WRONG POSITION	IRM detector not fully inserted.	Reactor Mode switch in RUN.

SCRAM TRIPS

Trip	Setpoint	Bypassed
IRM UPSCALE	≤ 121/125 of scale	Reactor Mode switch in RUN IF companion APRM is not downscale.
IRM INOPERATIVE	1) Module unplugged 2) High voltage low 3) IRM Mode switch not in "OPERATE" 4) Loss of negative supply voltage	Reactor Mode switch in RUN IF companion APRM is not downscale.

2. INTERLOCKS AND SETPOINTS

2.1 INTERLOCKS

2.1.1 To ensure each IRM is on the correct range, a rod block trip is initiated any time the IRM is both downscale and not on the lowest and most sensitive scale (Range 1).

2.1.2 A rod block is initiated if IRM detectors are not fully inserted in the core and reactor MODE switch is not in RUN.

2.1.3 IRM scram trips are automatically bypassed when reactor MODE switch is in RUN and APRMs are ≥ 3.0% RTP.

2.1.4 IRM rod block trips are automatically bypassed when reactor MODE switch is in RUN.

2. INTERLOCKS AND SETPOINTS

2.1 INTERLOCKS

2.1.1 All four SRM detectors can be fully withdrawn without causing a rod withdrawal block when all of the IRM RANGE switches are set to Range 3 or above and the IRM channels are indicating above the downscale trip point.

2.2 SETPOINTS

Function	Action
2.2.1 SRM Inoperative.	Rod, block, annunciator, amber light on Panel 9-5, local white light.
2.2.2 SRM Downscale (≥ 3 cps).	Rod block, annunciator, white light on Panel 9-5, local white light.
2.2.3 SRM Period (faster than 50 seconds).	Annunciator, local amber light, amber light on Panel 9-5.
2.2.4 Detector Retract Not Permissive (≥ 100 cps).	Rod block, annunciator, local white light.
2.2.5 SRM Bypassed.	White light on Panel 9-5, local white light.
2.2.6 SRM Upscale (≤ 1 x 10^5 cps).	Rod block, annunciator, amber light on Panel 9-5, local amber light.
2.2.7 SRM High-High (≤ 5 x 10^5 cps).	Annunciator, red light on Panel 9-5, local red light (reactor non-coincident scram if RPS shorting link switches are open).

PROCEDURE 4.1.1 REVISION 24 PAGE 13 OF 14

Range switch interlocks

791E258

- Range 8
  - All Div 1 on range 8 and above bypasses SRM Div 1 high and inop rod blocks. Div 2 same concept. sh10

RPS Instrumentation
3.3.1.1

Table 3.3.1.1-1 (page 1 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Intermediate Range Monitors					
a. Neutron Flux — High	2	3	G	SR 3.3.1.1.1 SR 3.3.1.1.3 SR 3.3.1.1.4 SR 3.3.1.1.5 SR 3.3.1.1.6 SR 3.3.1.1.12[(a,b)] SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 121/125 divisions of full scale
	5[(c)]	3	H	SR 3.3.1.1.1 SR 3.3.1.1.3 SR 3.3.1.1.4 SR 3.3.1.1.12[(a,b)] SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 121/125 divisions of full scale
b. Inop	2	3	G	SR 3.3.1.1.3 SR 3.3.1.1.4 SR 3.3.1.1.13	NA
	5[(c)]	3	H	SR 3.3.1.1.3 SR 3.3.1.1.4 SR 3.3.1.1.13	NA
2. Average Power Range Monitors					
a. Neutron Flux — High (Startup)	2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.3 SR 3.3.1.1.4 SR 3.3.1.1.6 SR 3.3.1.1.8 SR 3.3.1.1.10[(a,b)] SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 14.5% RTP
b. Neutron Flux-High (Flow Biased)	1	2	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.4 SR 3.3.1.1.7 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.10[(a,b)] SR 3.3.1.1.12[(a,b)] SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 0.75 W + 62.0% RTP[(d)]

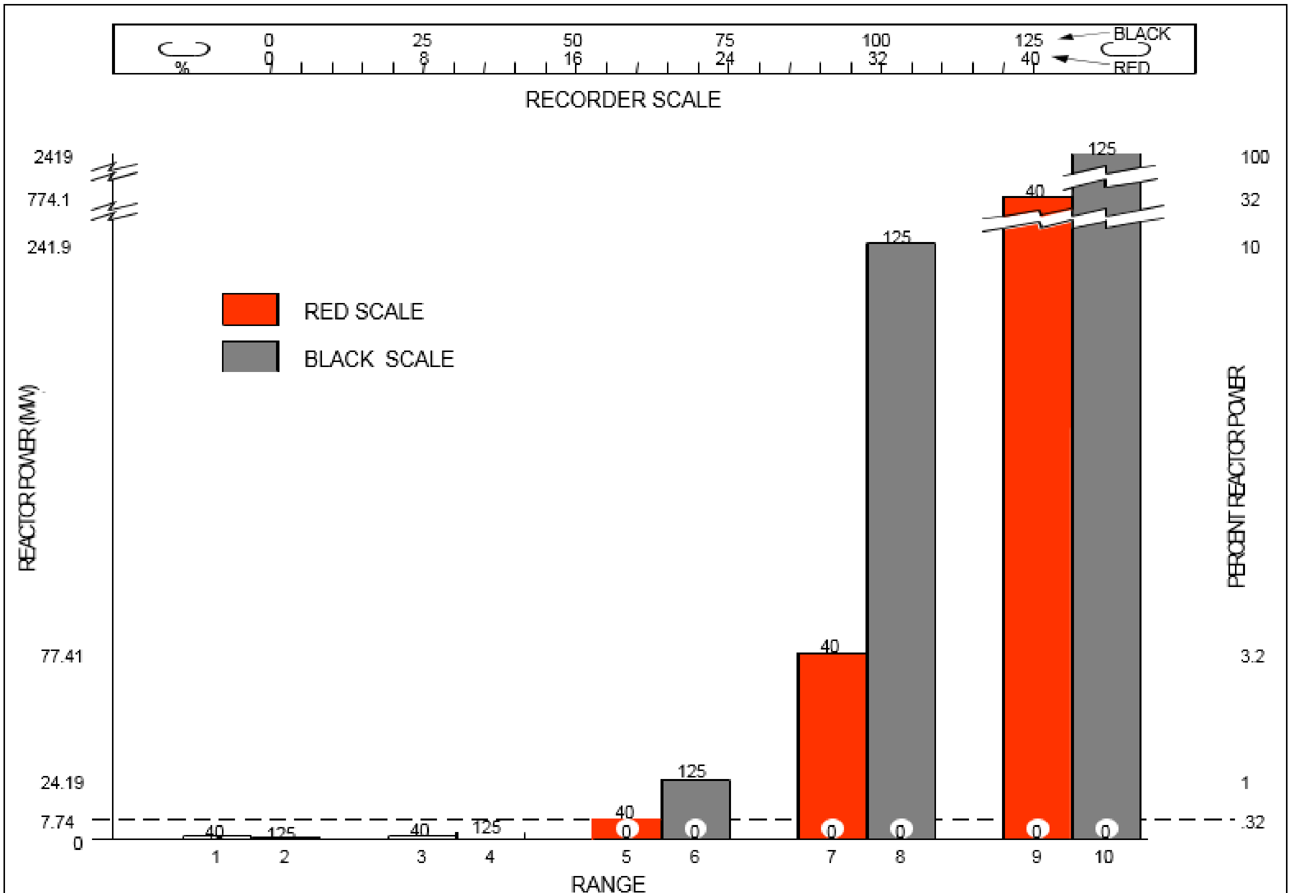
(continued)

(a) If the as-found channel setpoint is outside its predefined as-found tolerance, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

(b) The instrument channel setpoint shall be reset to a value that is within the as-left tolerance around the Limiting Trip Setpoint (LTSP) at the completion of the surveillance; otherwise, the channel shall be declared inoperable. Setpoints more conservative than the LTSP are acceptable provided that the as-found and as-left tolerances apply to the actual setpoint implemented in the Surveillance procedures (Nominal Trip Setpoint) to confirm channel performance. The Limiting Trip Setpoint and the methodologies used to determine the as-found and the as-left tolerances are specified in the Technical Requirements Manual.

(c) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

(d) [0.75 W + 62.0% - 0.75 ΔW] RTP when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating."



IRM RANGE & SCALE RELATIONSHIPS
FIGURE 10, REV. 10
COR002-12-02

Examination Outline Cross-Reference	Level	RO
223002 (SF5 PCIS) Primary Containment Isolation/Nuclear Steam Supply Shutoff Ability to (a) predict the impacts of the following on the PRIMARY CONTAINMENT ISOLATION SYSTEM/NUCLEAR STEAM SUPPLY SHUT-OFF; and (b) based on those predictions, use procedures to correct, control, or mitigate the consequences of those abnormal conditions or operations: A2.02 D.C. electrical distribution failures	Tier#	2
	Group#	1
	K/A #	223002 A2.02
	Rating	2.9
	Revision	0
Revision Statement:		

Question 14

The reactor is in Mode 2 at 500 psig.

The power panel supplying Group 4 Channel B isolation logic power was lost one minute ago.

With respect to Group 4 Channel B isolation logic ONLY…

(1) Is the logic tripped or NOT tripped?

AND

(2) Which one of the following procedures is required to be entered to mitigate this condition?

A. (1) Tripped
(2) 5.3DC125 [Loss of 125 VDC]

B. (1) Tripped
(2) Alarm Card C-1/F-2 [RPS Pwr Panel 1B Voltage Failure]

C. (1) NOT tripped
(2) 5.3DC125 [Loss of 125 VDC]

D. (1) NOT tripped
(2) Alarm Card C-1/F-2 [RPS Pwr Panel 1B Voltage Failure]

Answer: C

Explanation:
Portions of Group 4 (HPCI) isolation logic is powered from both 125 VDC Distribution Panel B via Panel BB2 and from 125 VDC Distribution Panel A via Panel AA2. Group 4 logic is energize to isolate. Redundancy is provided for PCIS such that no single failure will prevent isolation.

Loss of 125 VDC Panel B results in loss of logic power to Group 4 channel B. Since Group 4 isolation logic is energize to trip, no isolation signal is generated.

Loss of 125 VDC Distribution Panel B requires entry into procedure 5.3DC125 and does not directly result in a reactor scram or Group isolation. Only procedure 5.3DC125 is required to be entered, since no isolation occurred.

Distracters:
Answer A part 1 is plausible because some Group isolation logic is de-energize to trip, such as for Groups 1, 3, and 6. It is wrong because Group 4 logic is energize to trip, so no isolation signal is generated. Part 2 is correct.

Answer B part 1 is plausible and wrong for the same reason given for distractor A. Part 2 is plausible because RPS supplies logic power for some isolation Groups, such as Groups 1, 3, and 6. The first step to mitigate loss of RPS B power is to transfer RPS B to its alternate power supply IAW Alarm Card C-1/F-2. It is wrong because 125 VDC supplies power to Group 4 isolation logic, so procedure 5.3DC125 is required to be entered. RPS B remains energized, so Alarm Card C-1/F-2 entry is not required.

Answer D part 1 is correct. Part 2 is plausible and wrong for the reason given for distractor B.

Technical References: GE dwg 791E271 sheets 2, 3, 4; Procedure 5.3DC125 [Loss of 125 VDC](Rev 44), Lesson Plan COR002-03-02 [Ops Containment](Rev 35), Alarm Card C-1/F-2 [RPS Pwr Panel 1B Voltage Failure](Rev 33)

References to be provided to applicants during exam: none

Learning Objective: COR002-07-02 Obj LO-3f, (for HPCI) Given a specific loss or malfunction of the DC Distribution system, indicate the effect the loss or malfunction would have on the following systems, include in this discussion:

- The systems ability to automatically initiate and perform its intended function.
- The systems ability to be manually initiated and perform its intended function.
- The actions necessary outside of the control room to be performed to mitigate the loss or the failure of this system to operate as intended (if any).

COR002-03-02 Obj. LO-6n, Describe the interrelationship between PCIS and the following: DC Distribution; 6d, HPCI

Question Source:	Bank #	

(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(7),(10)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA Applicability:		
Top 10 Risk Significant Systems – Emergency DC Power, PCIS, HPCI		

From GE dwg 791E271 sh 2

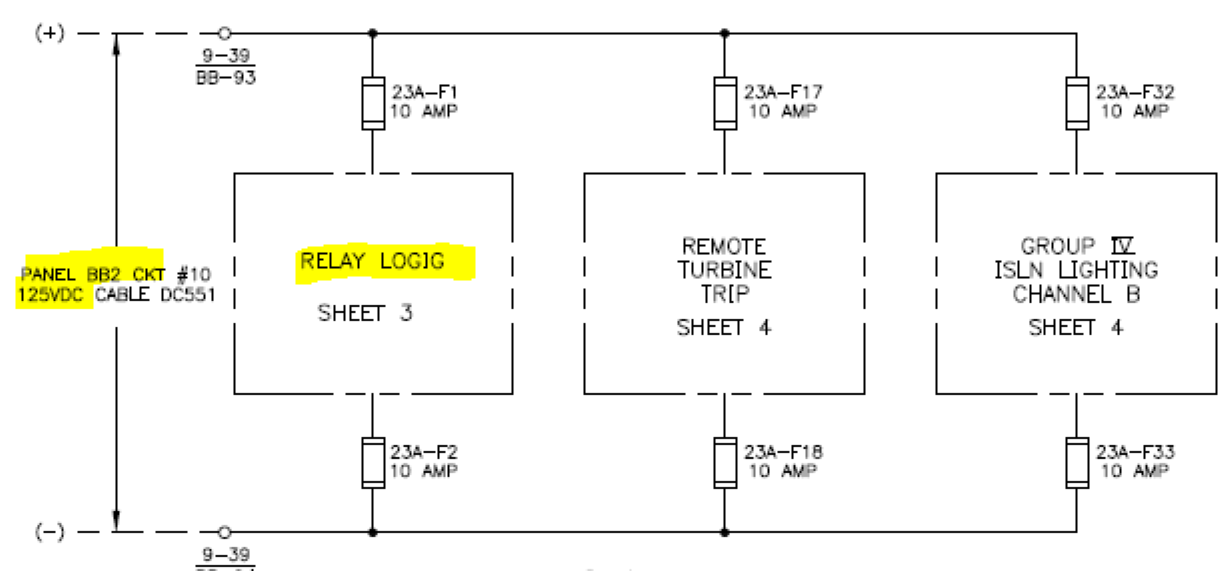


FIG 1

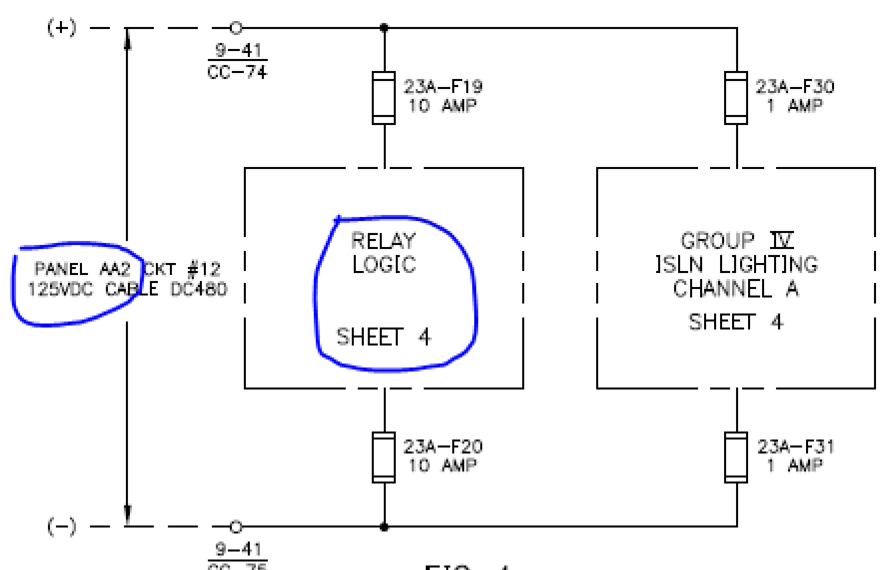
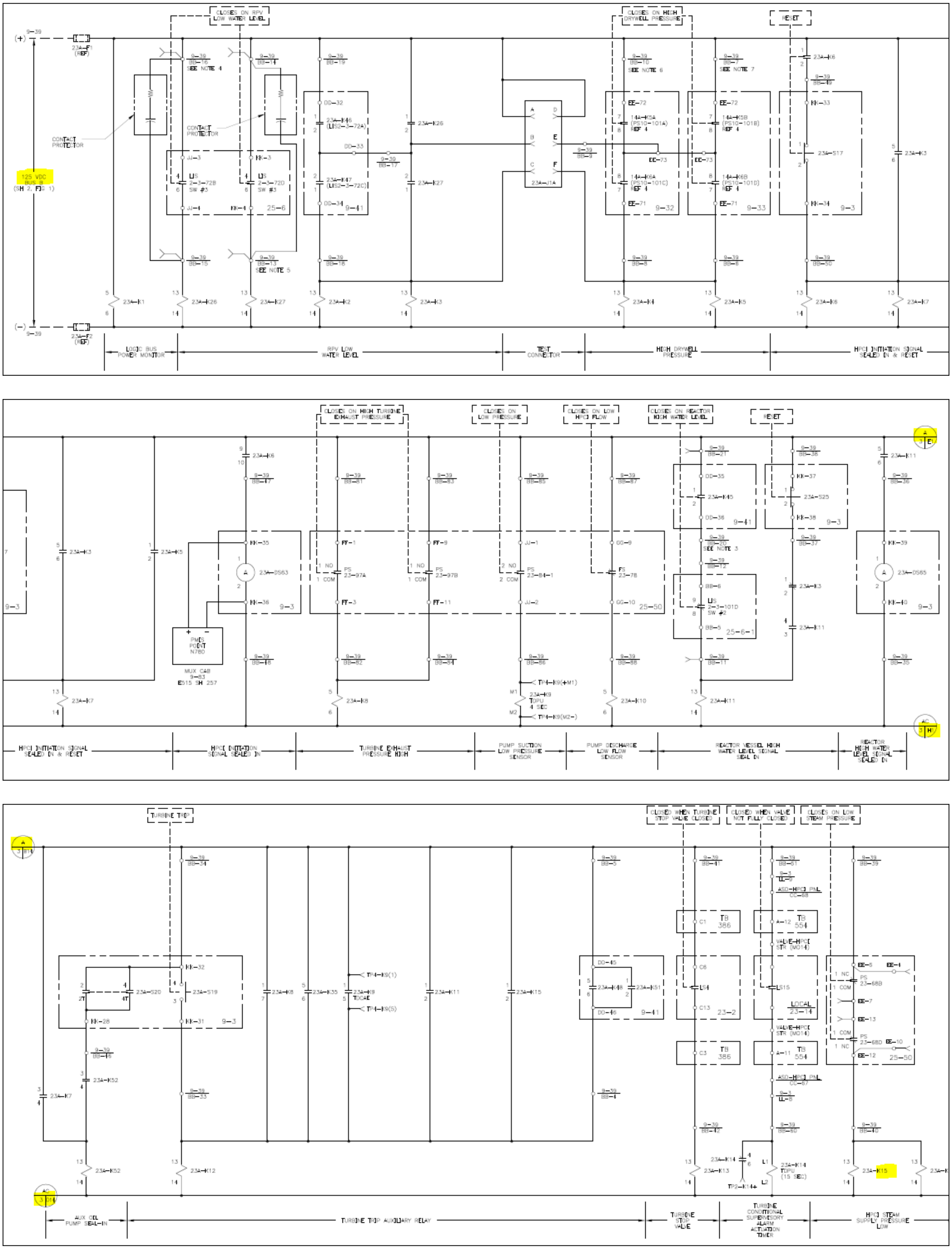
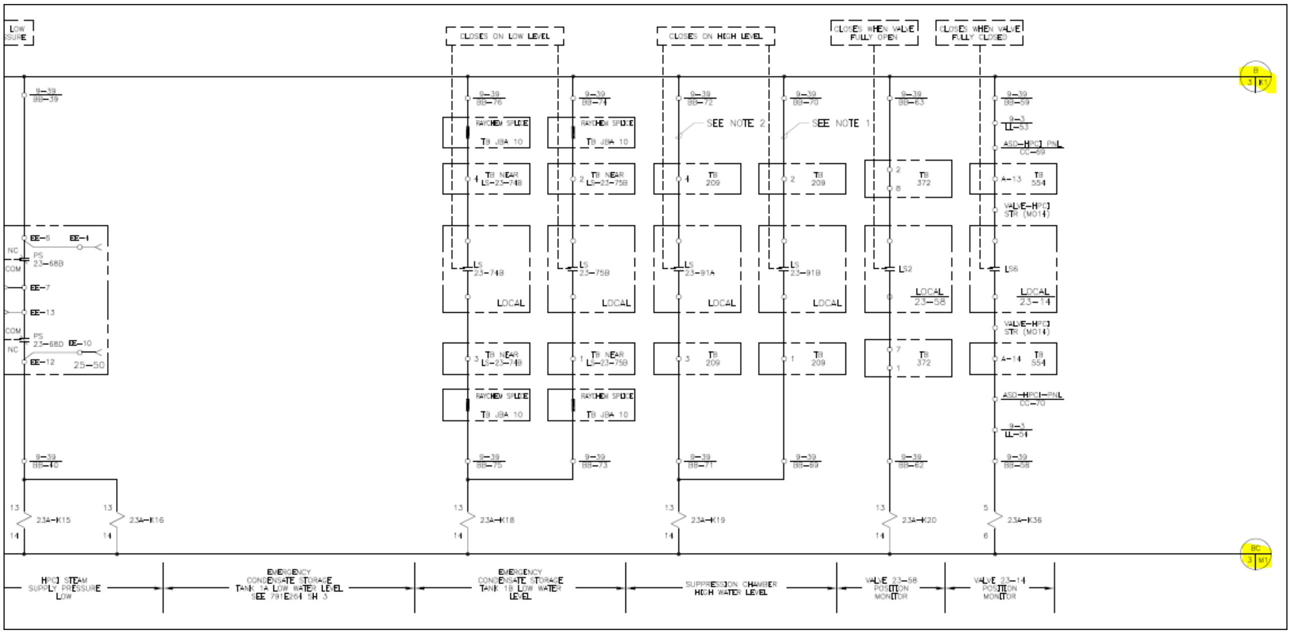
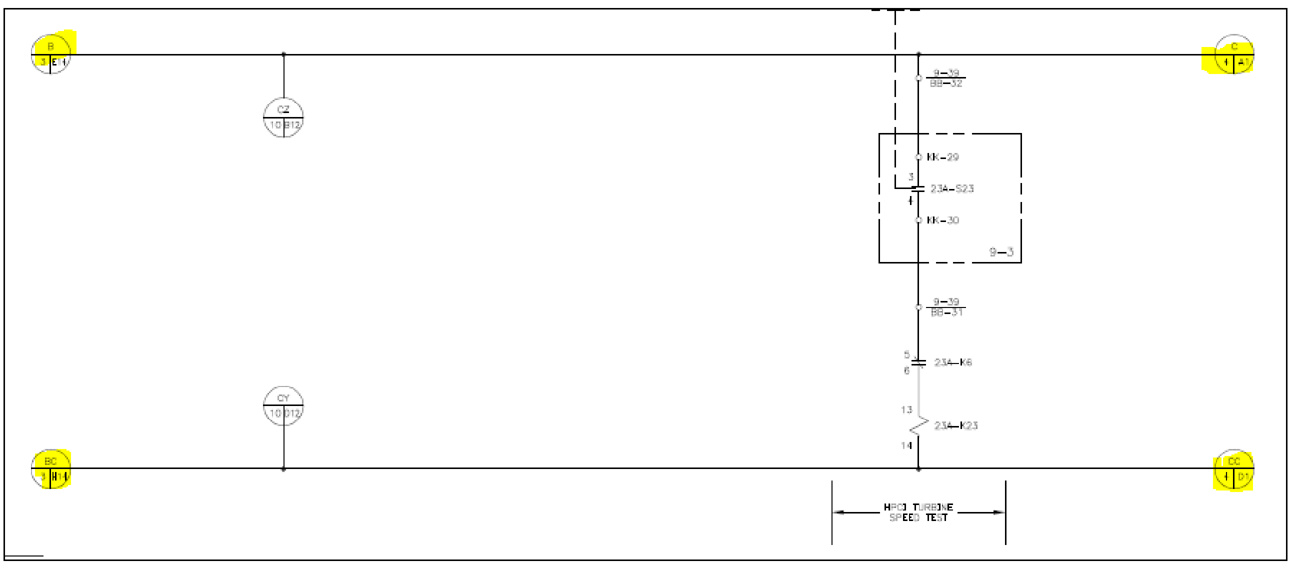


FIG 4

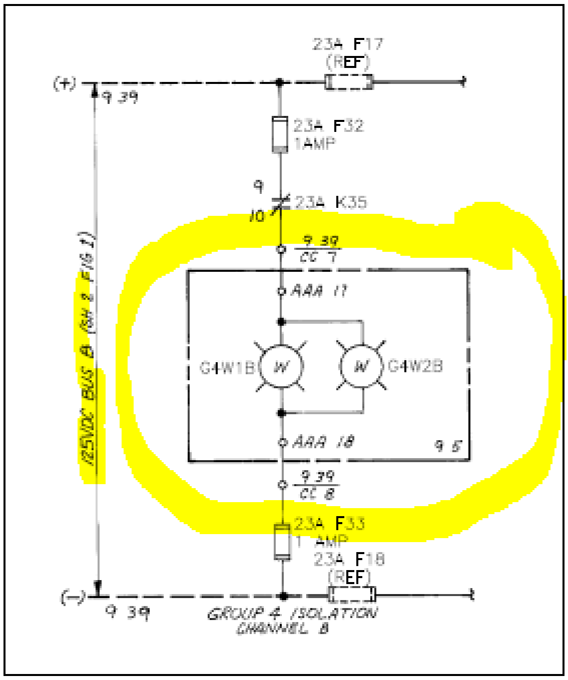
From GE dwg 791E271 sh 3

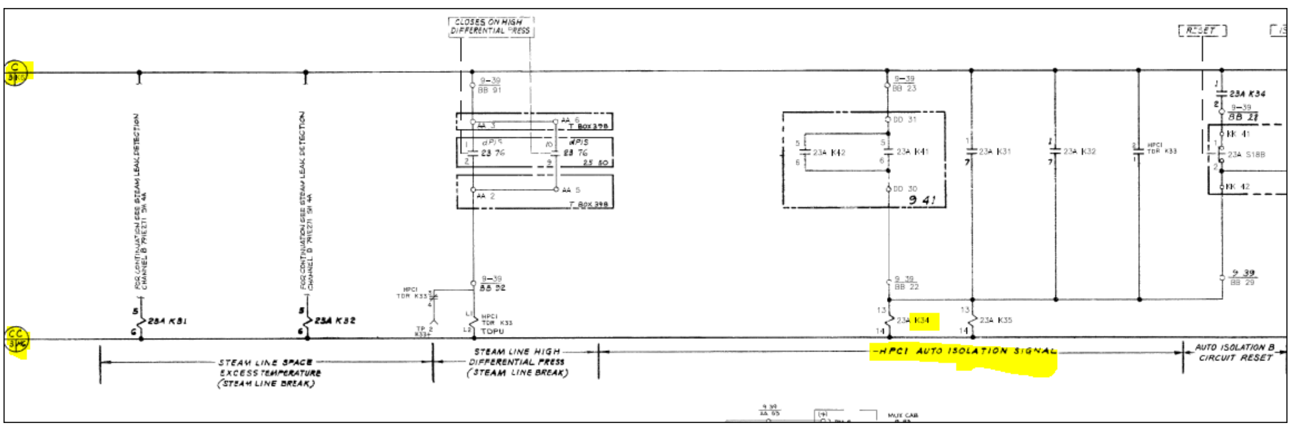




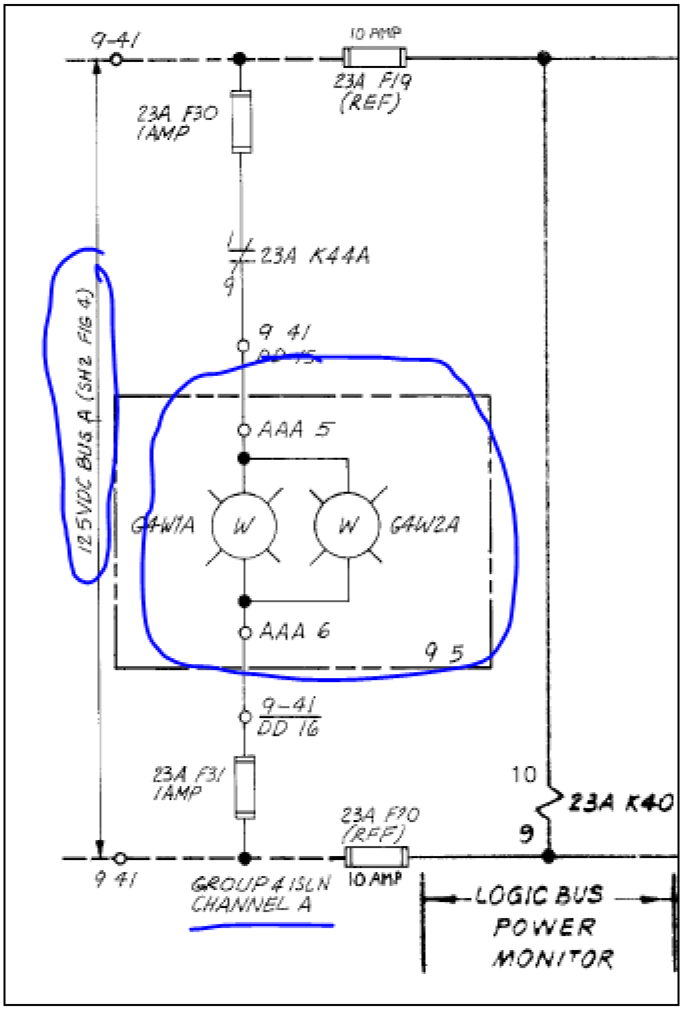


From GE dwg 791E271 sh 4





From GE dwg 791E271 sh 4



11. Group 4 Isolation HPCI system

a. Isolation Signals

LO-06d
LO-21b, 24d

1) High temperature in the HPCI steam line area (≤ 195ΣF).

2) High flow in the HPCI steam supply line (≤ 250% of rated flow with a six second time delay).

3) Low pressure in the HPCI steam supply line (≥ 107 psig).

b. Operations

1) Full Group 4 Isolation

a) Closes the HPCI Steam Supply Line Isolation valves (MO-15 & 16).

b) Closes the HPCI Pump Suction valve from the Suppression Pool (MO-58) if the HPCI Pump Suction valve from the ECSTs (MO-17) is full open.

c) Closes the HPCI Turbine Steam Exhaust Line Drain Pot Drain valves (AO-70 & 71).

d) Causes a HPCI turbine trip, which also closes the HPCI Minimum Flow valve (MO-25).

2) Half Group 4 Isolation

a) If Logic A trips, Steam Supply Inboard Isolation valve, HPCI-MO-15, Turbine Exhaust Line Drain Pot Drain valves HPCI-AO-70, and HPCI-AO-71 close, and HPCI turbine trips.

b) If Logic B trips, Steam Supply Outboard Isolation valve, HPCI-MO-16, HPCI-MO-58(if HPCI-MO-17 is full open), HPCI-AO-70, and HPCI-AO-71 close, and HPCI turbine trips.

c. Manual Isolation

LO-13c

The manual isolation pushbutton on Panel 9-3 will only cause a HPCI system isolation if an automatic HPCI system start signal is present Manual isolation trips logic B only.

d. Resetting a Group 4 Isolation

LO-13e

1) Two isolation reset pushbuttons on Panel 9-3, when depressed, will reset the Group 4 isolation signal caused by the high flow, high temperature, or the manual pushbutton.

2) If the cause of the isolation was steam line low pressure, the Group 4 isolation lights on Panel 9-5 will not extinguish. Also, the isolation is automatically reset if the pressure rises above the isolation setpoint. (For further information refer to the HPCI text.)

CNS OPERATIONS MANUAL EMERGENCY PROCEDURE 5.3DC125 LOSS OF 125 VDC	USE: CONTINUOUS QUALITY: QAPD RELATED EFFECTIVE: 7/24/19 APPROVAL: ITR-RDM OWNER: OSG SUPV DEPARTMENT: OPS

Scram Actions

1. ENTRY CONDITIONS

1.1 Multiple alarms on remaining Control Room annunciator panels, indicating loss of DC control power.

1.2 Loss of all 125 VDC.

2. AUTOMATIC ACTIONS

2.1 None.

3. IMMEDIATE OPERATOR ACTIONS

3.1 None.

4. SUBSEQUENT OPERATOR ACTIONS

4.1 Record current time and date. Time/Date: _______ / _________

4.2 Enter applicable Attachment(s):

LOSS OF 125 VDC DISTRIBUTION PANEL A	Attachment 1	Page 3
LOSS OF 125 VDC DISTRIBUTION PANEL B	Attachment 2	Page 9
LOSS OF PANEL AA1	Attachment 3	Page 14
LOSS OF PANEL AA2	Attachment 4	Page 18
LOSS OF PANEL AA5	Attachment 6	Page 22
LOSS OF PANEL BB1	Attachment 7	Page 23
LOSS OF PANEL BB2	Attachment 8	Page 26
LOSS OF PANEL BB3	Attachment 9	Page 28
LOSS OF PANEL DG-1	Attachment 10	Page 30
LOSS OF PANEL DG-2	Attachment 11	Page 31
LOSS OF ALL 125 VDC	Attachment 12	Page 32

Scram Actions

RPS PWR PANEL 1B VOLTAGE FAILURE

PANEL/WINDOW: C-1/F-2

1. AUTOMATIC ACTIONS

   1.1 RPS Channel B half scram.

   1.2 Loss of B, D, and F APRM indication.

   1.3 APRM B, D, F INOP Trip.

   1.4 Channel B Rod Block.

   1.5 Full Group 6 isolation.

   1.6 Div 2 Group 2, 3, and 7 isolations.

   1.7 Div 2 Group 1 isolation (MS-MO-77 closes).

2. OPERATOR OBSERVATION AND ACTION

   2.1 IF a RPS power supply available, THEN transfer RPS B to available source.

   2.2 Reset RPS Channel "B" half scram per Procedure 2.1.5.

   2.3 Reset Group Isolations per Procedure 2.1.22.

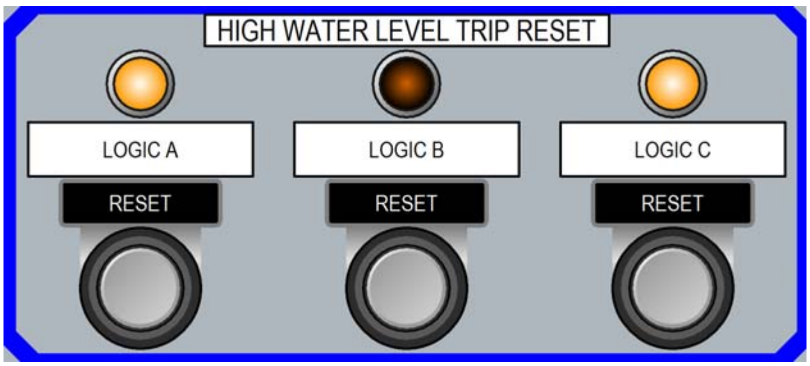
   2.4 Dispatch Operator to RPS B Room to check EPAs and RPS MG Set B to determine cause of failure.

   2.5 WHEN cause of failure has been determined and corrected, THEN place RPS B on desired source per Procedure 2.2.22.

Examination Outline Cross-Reference	Level	RO
259002 (SF2 RWLCS) Reactor Water Level Control Ability to manually operate and/or monitor in the control room: A4.11 High level lockout reset controls: Plant-Specific	Tier#	2
	Group#	1
	K/A #	259002 A4.11
	Rating	3.5
	Revision	0
Revision Statement:		

Question 15

The plant is at 100% power when RPV water level rises due to a Master Level Controller failure, resulting in the following indications on Panel 9-5:



(1) What is the status of RFPT B?

AND

(2) Which one of the following values is the HIGHEST Narrow Range reactor water level that depressing the above RESET button(s) will cause the tripped logic channel(s) to reset?

A. (1) Tripped
(2) 52 inches

B. (1) Tripped
(2) 56 inches

C. (1) Running
(2) 52 inches

D. (1) Running
(2) 56 inches

Answer: A

Explanation:
There are three reactor water level high channels in RVLCS. The trip logic is derived from narrow range water level instrumentation and is arranged in a 2-out-of-3 taken once scheme, with a trip setpoint of 54” (TS). When any two channels trip, a trip signal is sent to both RFPTs and the Main Turbine. The amber lights pictured in the stem indicate channels A and C are tripped, since the associated lights are illuminated. With channels A and C tripped, both RFPTs are tripped and cannot be reset until reactor water level is below 54”.

Distracters:
Answer B part 1 is correct. Part 2 is plausible because HPCI also trips on reactor water level high, 54”. However, its instrumentation is derived from wide range water level instrumentation. (One wide range level instrumentation is an input to RVLCS, but it does not input into the high water level trip logic.) Wide range level indicates approximately 5” lower than narrow range level instrumentation at 100% power due to differing calibration conditions (WR is calibrated to no Jet Pump Flow). Therefore, the HPCI high reactor water level trip does not occur until ~ 59” indicated on narrow range. This answer would be correct if the question concerned HPCI or if RFPT trip was derived from wide range level instrumentation. It is wrong because the RFPT trip is derived from narrow range instrumentation, thus narrow range must be below 54”.

Answer C part 1 is plausible for two reasons. First, an examinee may believe an extinguished light indicates the channel is tripped, since PCIS isolation status logic lights on Panel 9-5 extinguish to indicate isolation logic is tripped. Thus the examinee may believe only one channel is tripped and both RFPTs are still operating. Second, an examinee who realizes channels A and C are tripped may believe all three channels must be tripped to result in RFPT trips. This answer is wrong because two of the channels are tripped, indicated by the illuminated logic channel lights. Therefore the necessary logic requirements are satisfied to cause both RFPTs to trip.

Answer D part 1 is plausible and wrong for the same reason given for distractor C. Part 2 is plausible and wrong for the same reason given for distractor B.

Technical References: Lesson plan COR002-32-02 [Ops Reactor Vessel Level Control](Rev 24), Lesson plan COR002-15-02 [Ops Nuclear Boiler Instrumentation](Rev 28), procedure 4.4.1 [Reactor Vessel Level Control System](Rev 10)

References to be provided to applicants during exam: none

Learning Objective: COR002-32-02 Obj LO 3j, Describe the RVLC system design features and/or interlocks that provide for the following: Reactor Vessel Overfill Protection

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)((7)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA Applicability:		
Top 10 Risk Significant System – Nuclear Boiler Instrumentation		

Lesson Number: COR002-32-02 Revision: 24

Interlock/Trip	Initiating Device/ Setpoint	Additional Functions
e) Tripped Main condensate booster pump enhancement logic	Total steam flow > 8 .25 Mlbm/Hr concurrent with a condensate booster pump low discharge header pressure MC-PT-6, < 450 psig and a condensate booster pump tripped (flow < 2500 gpm)	The RVLC System utilizes running MCBP. When actuated, this will cause the recirc pumps to runback toward 45%.
f) RFP Low Suction Runback enhancement logic	Total steam flow > 8 .25 Mlbm/Hr and RFP suction pressure < 350 psig .RF-PT-2A and RF-PT-2B.	RFP suction pressure is to provide input to the Low Suction Runback enhancement logic. When actuated, this will cause the recirc pumps to runback toward 45%.
g) RFP tripped/low flow with RPV low level enhancement logic	Total steam flow > 9 Mlbm/Hr with at least 1 RFP tripped/flow < 1 Mlbm/Hr and selected reactor water level < 27.5".	When actuated, this will cause the recirc pumps to runback toward 45%.
h) High RPV water level RFP and Main Turbine Trip	≤+54.0" (2 out of 3 logic)	Trips the Main Turbine and RFPs. Must be manually reset with pushbuttons when level below setpoint.
i) Main Generator Output Breaker Interlock	5% steam flow (steam flow relay 52Y)	Will prevent closure of the Main Generator output breakers until steam flow is above the setpoint.

Lesson Number:	COR002-32-02	Revision: 24

d) RFC-CS-RFPT1A, RFPT-1A Primary Control Station HMI (PNL 9-5)	HMI	Control and indication of RVLCS/RFPTCS Power supply – CCP-1A
e) RFC-CS-RFPT1B, RFPT-1B Primary Control Station HMI (PNL 9-5)	HMI	Control and indication of RVLCS/RFPTCS Power supply – CCP-1B
f) RFC-CS-RFPT1A, RFPT-1A Secondary Control Station HMI (PNL A)	HMI	Control and indication of RVLCS/RFPTCS Power supply – CCP-1A
g) RFC-CS-RFPT1B, RFPT-1B Secondary Control Station HMI (PNL A)	HMI	Control and indication of RVLCS/RFPTCS Power supply – CCP-1B
h) High Water Level Trip Logic Reset Pushbuttons (3)	Pushbutton	Resets the high level trip circuit

1	E.	Basic System Operation
-02k, 3e, f		

The Reactor Vessel Level Control system regulates the flow of water to the reactor vessel by controlling either feed pump speed or startup valve position. This system may be operated in manual or automatic and in either auto (3) element or single element mode, reactor pressure follow mode, or discharge pressure follow mode. The operator may select which mode of operation is to be used by the system with a selector switch and HMIs located in the Control Room.

The Reactor Vessel Level Control System (RVLCS) uses the narrow range reactor vessel level instrumentation and one wide range instrument that measures the normal operating range of water level indications. This system measures the water level in the reactor vessel, the feedwater flow rate into the reactor vessel, and the steam flow rate from the reactor vessel. Other system pressures and temperatures will be monitored for compensation purposes. Three element or single element automatic control, as well as manual control, are provided. During three-element automatic operation, these three measurements are used to

Page 7 of 85

Lesson Number: COR002-32-02	Revision: 24

Lesson Number:	COR002-15-02	Revision: 28

3) The reactor jet pump flow in the annulus region outside the core shroud and past the lower tap of the Wide Range instruments has a significant velocity head and some friction loss which reduces the pressure on the variable leg to the differential pressure (level) instrument, resulting in an indicated level lower than actual.

e. Main Turbine and Feedwater

LO-06e
SO-02d,04d

Upon a loss of NBI, the Main Turbine and RFPs may or may not trip depending on how the instruments fail. The high water level trip signal to the Main Turbine and RFPs is supplied by the Narrow Range level instrumentation.

f. Diesel Generators

LO-06f
SO-02b,04e

The Diesel Generators receive their automatic low level start signal from the Wide Range level instruments. On a loss of NBI, the Diesel Generators may or may not auto start depending on how the level instruments fail.

Page 48 of 70

Lesson Number:	COR002-15-02	Revision:	28

5.30 At Panel 9-5, press and release HIGH WATER LEVEL TRIP RESET pushbuttons, as dictated by plant conditions, for following:

5.30.1 LOGIC A.

5.30.2 LOGIC B.

5.30.3 LOGIC C.

PROCEDURE 4.4.1 REVISION 10 PAGE 9 OF 72

Examination Outline Cross-Reference	**Level**	RO
239002 (SF3 SRV) Safety Relief Valves 2.1.32 Ability to explain and apply system limits and precautions.	**Tier#**	2
	Group#	2
	K/A #	239002 G2.1.32
	Rating	3.8
	Revision	0
Revision Statement:		

Question 16

Procedure 2.2.1 [Nuclear Pressure Relief System] states:

SRV operation is prohibited when Main Steam System pressure is below _(1)_ psig.

AND

The basis for this limitation is ____(2)____ .

A. (1) 50
(2) SRV tailpipe damage may occur.

B. (1) 50
(2) The SRV can NOT be relied upon to open.

C. (1) 70
(2) SRV tailpipe damage may occur.

D. (1) 70
(2) The SRV can NOT be relied upon to open.

Answer: B
Explanation: Procedure 2.2.1 P&L 2.2 states Safety/relief valve operation prohibited with Main Steam System less than 50 psig. This is because the valve springs will cause the SRVs to close when RPV pressure lowers to ~50 psig; therefore, an SRV cannot be relied upon to open if RPV pressure is <50 psig.
Distracters: Answer A part 1 is correct. Part 2 is plausible because a caution preceding procedure 2.2.1 step 5.1 relates to an opening restriction for SRVs to prevent SRV tailpipe damage. Also, the SRV tailpipe level limit in EOPs is associated with SRV operation and SRV tailpipe damage. The examinee who confuses these restrictions on opening

SRVs may choose this answer. It is wrong because the caution at step 5.1 requires waiting a minimum of 3 minutes before reopening a SRV, due to water being drawn into the SRV tailpipe from the SP due to the vacuum created as steam in the tailpipe cools and is not based directly on RPV pressure. Also, SRV tailpipe damage associated with the SRV tailpipe level limit is based on SP level, not RPV pressure.

Answer C part 1 is plausible because it is just below a recognizable value associated with RPV cooldown using SRVs. 72 psig is the RPV low pressure permissive for placing Shutdown Cooling in service. It is wrong because Procedure 2.2.1 P&L 2.2 states SRV operation is prohibited with MS pressure below 50 psig. Part 2 is plausible and wrong for the reason stated for distractor A.

Answer D part 1 is plausible and wrong for the reason stated for distractor C. Part 2 is correct.

Technical References: Procedure 2.2.1 [Nuclear Pressure Relief System](Rev 39), Lesson plan COR002-16-02 [Ops Nuclear Pressure Relief](Rev 21), PSTG [AMP-TBD00 EOP Technical Basis](Rev 10)

References to be provided to applicants during exam: none

Learning Objective: COR002-16-02 Obj LO-6b, Briefly describe the following concepts as they apply to NPR: Relief function of SRV operation

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(7),(10)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA Applicability:		
Top 10 Risk Significant System – ADS/SRV		

2. PRECAUTIONS AND LIMITATIONS

2.1 Three relief valves required available for Alternate Decay Heat Removal during MODE 3 or 4.

2.2 Safety/relief valve operation prohibited with Main Steam System less than 50 psig.

3. PREREQUISITES

3.1 **ENSURE** following available:

- Plant Air System.
- Primary Containment Nitrogen Makeup System when PC inert.

3.2 **ENSURE** following complete:

- Procedure 2.2.1A.
- Procedure 2.2.1B.

1.1.4 The relief valves may be manually opened by positioning switches in the Control Room when the reactor pressure is > 50 psig.

1.2 OPERATING CHARACTERISTICS

1.2.1 The ADS serves as a backup to the HPCI System under Loss Of Coolant Accident conditions. If the water level lowers to the initiation setpoint level and does not recover, a 109 second time delay relay energizes and starts timing. At the end of the time delay, if a low pressure CSCS pump is developing sufficient discharge pressure (AC interlock) to inject into the reactor vessel, relief valves MS-RV-71A, MS-RV-71B, MS-RV-71C, MS-RV-71E, MS-RV-71G, and MS-RV-71H open. This vents reactor steam to the suppression chamber; thereby, lowering the reactor pressure where the CS or RHR pumps are able to inject water.

PROCEDURE 2.2.1 REVISION 39 PAGE 11 OF 17

PROCEDURE 2.2.1 REVISION 39 PAGE 7 OF 17

5. MANUAL OPERATION

CAUTION – Relief valve tailpipe or suppression pool damage from water hammer may occur from immediately re-opening relief valve.

5.1 During manual main steam relief valve operations, **PERFORM** following:

- **ADHERE** to opening sequence indicated on Panel 9-3 valve control switch covers.
- **AVOID** opening individual valves greater than 2 minutes.
- **WAIT** greater than or equal to 3 seconds between openings.

At approximately 300 psig vessel pressure, the RHR and the Core Spray systems will start to inject. At this point, vessel level should start to increase. The relief valves will remain open until the initiation logic is reset, or when steam pressure has been reduced to the point

Page 30 of 43

Lesson Title: OPS Nuclear Pressure Relief	
Lesson Number: COR002-16-02	Revision Number: 21

(approximately 50 psig) where the valve springs will cause the valves to close. After the vessel water level is restored to greater than the initiation setpoint of -113", it is possible to reset the initiation signal. If conditions later change and ADS is required, the system will initiate again.

PSTG / SATG

AMP-TBD00
Tech. Basis – App. B

18.27 SRV Tail Pipe Level Limit

The SRV Tail Pipe Level Limit (STPLL) is the highest suppression pool water level at which opening an SRV will not result in exceeding the code allowable stresses in the SRV tail pipe, tail pipe supports, quencher, or quencher supports.

Examination Outline Cross-Reference	Level	RO
211000 (SF1 SLCS) Standby Liquid Control Ability to monitor automatic operations of the STANDBY LIQUID CONTROL SYSTEM including: A3.06 RWCU system isolation: Plant-Specific	Tier#	2
	Group#	1
	K/A #	211000 A3.06
	Rating	4.0
	Revision	0
Revision Statement:		

Question 17

Both SLC pumps A and B control switches are placed in START on panel 9-5.

- SLC Pump B breaker immediately trips when SLC Pump B switch is placed in START

Which one of the following completes the statement below regarding how RWCU is affected in this situation?

RWCU valve(s) __(1)__ receive(s) an isolation signal,
then the in-service RWCU pump trips due to __(2)__.

A. (1) MO-15, Inboard Isolation Valve, ONLY
(2) MO-15 reaching not fully open

B. (1) MO-15, Inboard Isolation Valve, ONLY
(2) RWCU flow dropping below 50 gpm

C. (1) MO-15, Inboard Isolation Valve and MO-18, Outboard Isolation Valve
(2) RWCU flow dropping below 50 gpm

D. (1) MO-15, Inboard Isolation Valve and MO-18, Outboard Isolation Valve
(2) MO-15 or MO-18 reaching not fully open

Answer: D

Explanation:
SLC A panel 9-5 control switch in START de-energizes isolation logic for RWCU suction valve MO-15 and SLC B panel 9-5 control switch in START de-energizes isolation logic for RWCU suction valve MO-18. PCIS Group 3 logic for RWCU-MO-15 and 18 is de-energize to isolate. The SLC pump start contacts are located in RWCU logic and these circuits do not rely on AC power from SLC system. Therefore, close

signals are completed for both MO-15 and MO-18 when SLC control switches are placed to START, and MO-15 and MO-18 close.

When the not fully open limit switch contact picks upon either MO-15 or MO-18, a trip signal to RWCU pumps is generated. This will occur at approximately 95% open position, essentially before MO-15 or MO-18 begin to throttle flow, thus before RWCU flow drops to 50 gpm.

Distracters:
Answer A part 1 is plausible because SLC Pump control circuits are powered via a 480V/120V transformer via the respective SLC pump breaker, and the stem implies SLC Pump B and its control circuit are de-energized 2 seconds after its control switch is taken to START. If the circuit for RWCU-MO-18 isolation was powered from this circuit, MO-18 would not reach not fully open position (~95% open). It is wrong because the SLC control switch contact is in the RWCU MO-18 control circuit, and receives power via MO-18 power, so MO-18 closes when the SLC B control switch contact closes. Part 2 is correct in that RWCU pumps trip before RWCU flow lowers to 50 gpm based on a suction valve, MO-15 or MO-18, reaching not fully open, ~95%, position.

Answer B part 1 is plausible and wrong for the reason stated for distractor A. Part 2 is plausible because RWCU flow < 50 gpm is also a pump trip, and isolation valves closing would eventually throttle RWCU flow below 50 gpm. It is wrong because MO-15 and MO-18 will reach not fully open position and trip the RWCU pump before flow lowers to 50 gpm.

Answer C part 1 is correct. Part 2 is plausible and wrong for the reason stated for distractor B.

Technical References: Procedure 2.2.66 [Reactor Water Cleanup](Rev 118), GE dwgs 791E262 sh 1, 791E263 sh 1,

References to be provided to applicants during exam: none

Learning Objective: COR002-29-02 Obj LO-5f, Describe the SLC design features and/or interlocks that provide for the following: RWCU isolation

Question Source:	Bank #	LOR Biennial Bank Q#49-4
(note changes; attach parent)	Modified Bank #	
	New	
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(7)	

Level of Difficulty:	3
SRO Only Justification:	N/A
PSA Applicability:	
Top 10 Risk Significant System - PCIS	

2. INTERLOCKS AND SETPOINTS

2.1 Any of following will cause RWCU pumps to trip:

2.1.1 RWCU-MO-15 or RWCU-MO-18 not full open.

2.1.2 High pump bearing cooling water (REC) temperature - 140°F.

2.1.3 Low RWCU flow rate - 50 gpm.

2.2 When starting a pump, switch must be held to START until system flow is > 50 gpm or pump will trip.

2.3 Any of following will close RWCU-MO-15, INBD ISOL VLV:

2.3.1 Reactor low water level - ≥ -42".

2.3.2 High area temperature - ≤ 195°F.

2.3.3 High system flow - ≤ 191% of Rated.

2.3.4 Non-regenerative heat exchanger outlet high temperature - ≤ 140°F.

NOTE – Starting SLC Pump B will not cause RWCU-MO-15 to close.

2.3.5 SLC System A initiation.

PROCEDURE 2.2.66 REVISION 118 PAGE 118 OF 122

2.4 Any of following will close RWCU-MO-18, OUTBD ISOL VLV:

2.4.1 Reactor low water level - ≥ -42".

2.4.2 High area temperature - ≤ 195°F.

2.4.3 High system flow - ≤ 191% of Rated.

2.4.4 Non-regenerative heat exchanger outlet high RWCU temperature - ≤ 140°F.

NOTE – Starting SLC Pump A will not cause RWCU-MO-18 to close.

2.4.5 SLC System B initiation.

2.5 Any of following will close RWCU-FCV-55, BLOWDOWN CONTROL VALVE:

2.5.1 Low upstream pressure - 5 psig.

2.5.2 High downstream pressure - 140 psig (PS-108A).

2.5.3 High downstream pressure - 40 psig (PS-108B).

2.6 If RWCU-FCV-55, BLOWDOWN CONTROL VALVE, automatically closed, then RWCU-RMC-143, BD VLV 55 FLOW CONTROL, must adjusted to zero to reset logic.

3. REFERENCES

3.1 TECHNICAL SPECIFICATIONS

3.1.1 LCO 3.3.6.1, Primary Containment Isolation Instrumentation.

3.1.2 LCO 3.6.1.3, Primary Containment Isolation Valves (PCIVs).

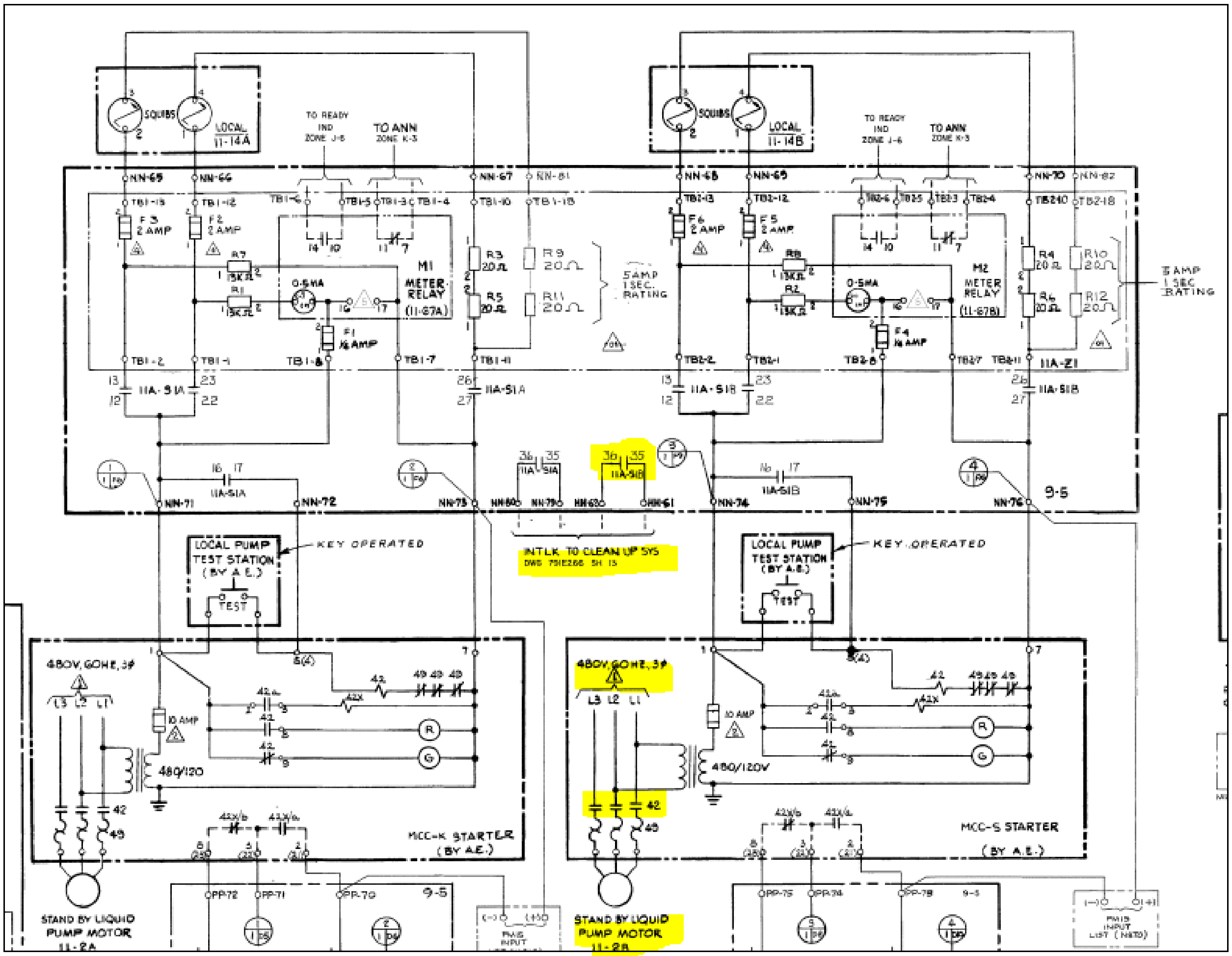
3.2 TECHNICAL REQUIREMENTS MANUAL

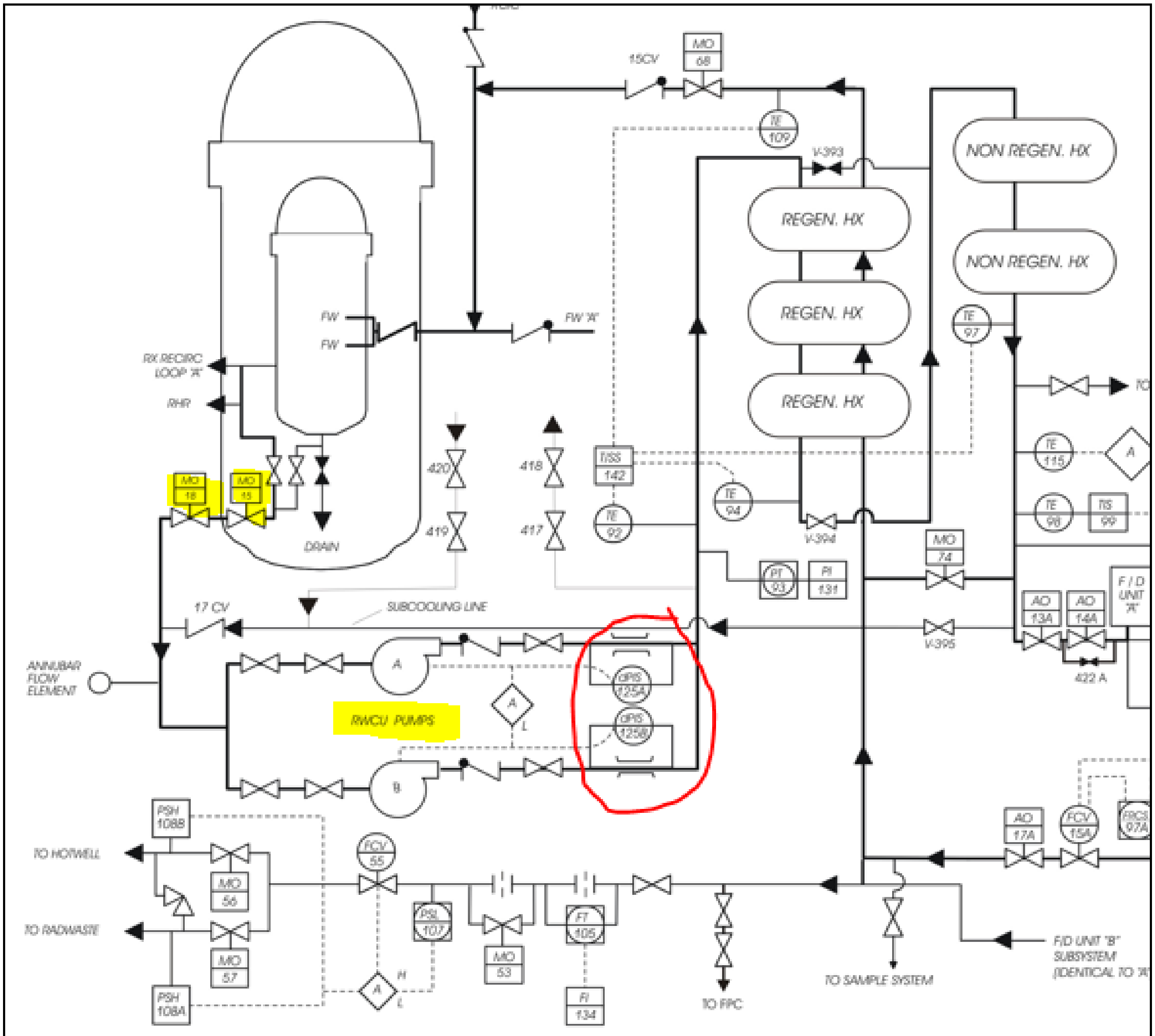
3.2.1 TLCO 3.4.1, RCS Chemistry.

3.3 UPDATED SAFETY ANALYSIS REPORT

3.3.1 Section IV-9.0, Reactor Water Cleanup System.

From GE dwg 791E262 sh 1



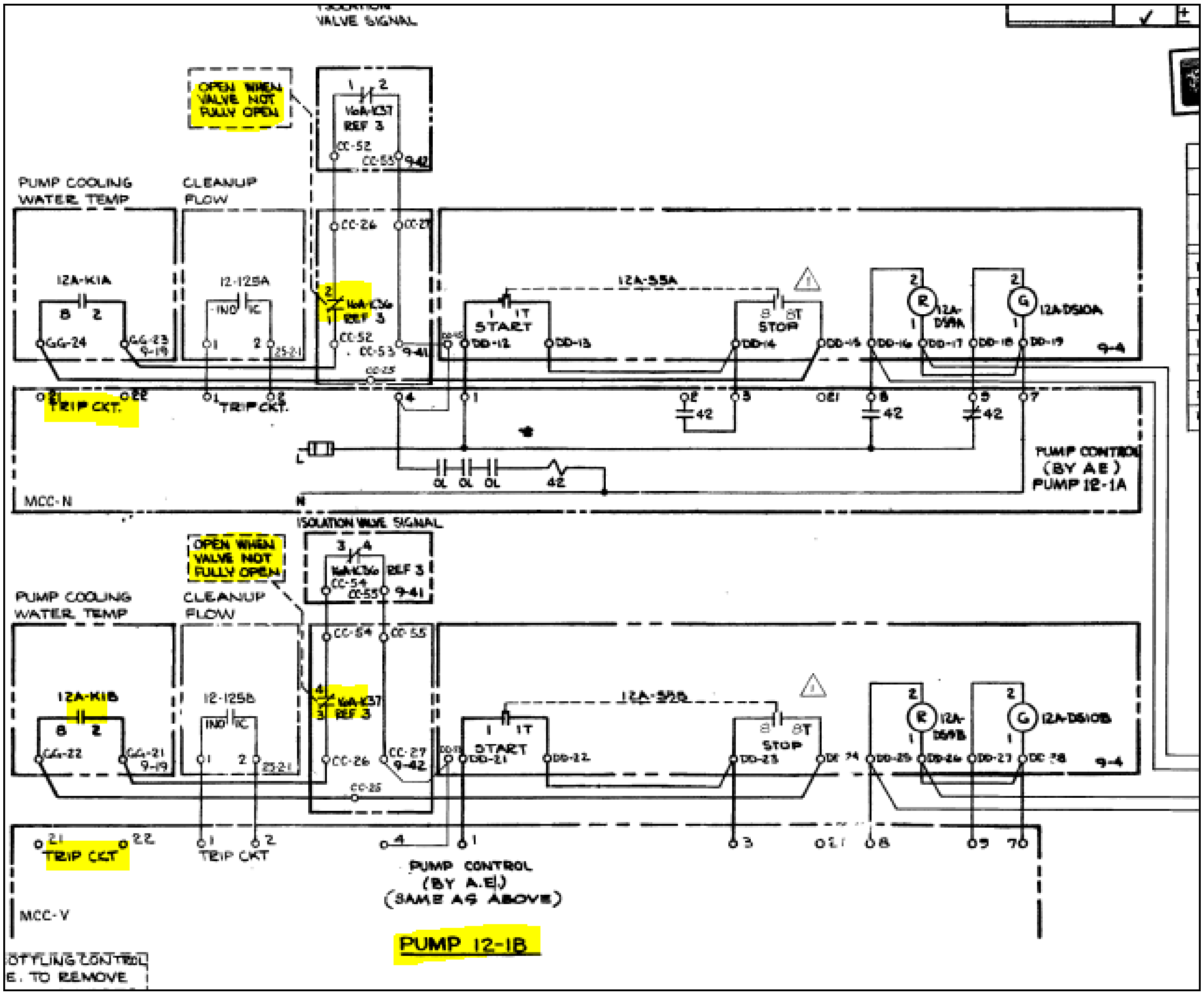


REACTOR WATER CLEAN-UP

Figure 1, Rev. 12

COR001-20

From GE dwg 791E263 sh 1



Examination Outline Cross-Reference	**Level**	RO
264000 (SF6 EGE) Emergency Generators (Diesel/Jet) EDG 2.4.46 Ability to verify that the alarms are consistent with the plant conditions.	**Tier#**	2
	Group#	1
	K/A #	264000 G2.4.46
	Rating	4.2
	Revision	0
Revision Statement:		

Question 18

DG1 was manually started for a monthly surveillance.

The following annunciator was received 20 seconds ago **and** DG1 is still running:

DIESEL GEN 1 EXCESSIVE VIBRATION	PANEL/WINDOW: C-1/F-3

(1) Is DG1 required to be tripped by the operator?

AND

(2) If this had been a valid automatic DG1 start, is DG1 required to be tripped?

A. (1) No
(2) No

B. (1) No
(2) Yes

C. (1) Yes
(2) No

D. (1) Yes
(2) Yes

Answer: C

Explanation:
Upon a normal (manual) start, the high vibration trip is bypassed for 30 seconds to allow the DG to come to rated speed and to stabilize. If high vibration remains after 30 seconds, the excessive vibration alarm will be received and, 5 seconds later, the DG will trip. Since the vibration alarm has been in for more than 5 seconds, an

automatic trip should have occurred, and the operator is required to trip the DG IAW Alarm Card C-1/F-3 step 2.1 to protect important plant equipment.

The high vibration trip is automatically bypassed on an emergency start of the DG, so the operator would not be required to trip the DG during an emergency start if the high vibration alarm remained in for >30 seconds.

Distracters:
Answer A part 1 is plausible because high vibration trip is bypassed sometimes and because the alarm does not come in until excessive vibration exists and a 30 second time delay expires. An examinee may believe another 5 seconds must pass before a trip signal is generated. It is wrong because the vibration trip is not bypassed during a monthly surveillance, and the alarm has been in for 20 seconds, so the DG should have tripped 15 seconds ago. Manually tripping the DG is required. Part 2 is correct.

Answer B part 1 is plausible and wrong for the same reason given for distractor A. Part 2 is plausible because high vibration is an automatic trip during a normal DG start if it remains in for >30 seconds, and operators are required to effect failed automatic actions. It is wrong because by design the high vibration trip is automatically bypassed during emergency DG starts, so the operator is not required to trip the DG.

Answer D part 1 is correct. Part 2 is plausible and wrong for the same reason given for distractor B.

Technical References: Lesson plan COR002-08-02 [Ops Diesel Generators](Rev 37), Alarm Card C-1/F-3 [Diesel Gen 1 Excessive Vibration](Rev 33), Procedure 14.17.7 [DG-1 Vibration Switch Testing and Maintenance](Rev 8)

References to be provided to applicants during exam: none

Learning Objective: COR002-08-02 Obj. LO-9a, Describe the Diesel Generator design feature(s) and/or interlock(s) that provide for the following: Diesel Generator Trips (Normal); 9b, Diesel Generator Trips (Emergency/LOCA)

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(7)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	

PSA Applicability:
Top 10 Risk Significant System – Emergency DGs

	DIESEL GEN 1 EXCESSIVE VIBRATION	PANEL/WINDOW: C-1/F-3

1. AUTOMATIC ACTIONS
   - 1.1 DG1 trips (trip bypassed on an auto start).
2. OPERATOR OBSERVATION AND ACTION
   - 2.1 Check DG1 tripped, if applicable.
   - 2.2 Determine cause of high vibration.
   - 2.3 Once cause determined, reset alarm per following:
     - 2.3.1 Press INCOMPLETE SEQUENCE RESET button on front of DG1 Control Panel and verify following:
       - 2.3.1.1 Local DG1 Control Panel alarm clears.
       - 2.3.1.2 Annunciator C-1/F-3 clears.
       - 2.3.1.3 Alarm VID displays 3605 DIESEL GEN 1 VIBRATION NORMAL.

LO-09a

Note: On an auto start, the following trips (e through j) are bypassed by the Non-emergency Trip Bypass Valve.

e. High Vibration

Vibration switches are used to shutdown the diesel if vibration of either the engine or the generator is excessive. Two vibration switches are used; one is located on the free end of the engine (northeast corner), and the other is located on the engine end of the generator (west side).

On a manual start, actuation of either vibration switch will de-energize the Electronic Trip Valve to vent the trip header which allows 80 psig air to extend the fuel control cylinder and shut down the diesel. A timer in the vibration switch circuitry overrides the vibration trip for 30 seconds during engine startup.

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Lesson/Course Number:	COR002-08-02 / 1452	Revision: 37

On an auto start, a contact in parallel with the vibration contact is closed keeping the Electronic Trip Valve energized. In addition, on an auto start the Non-emergency Trip Bypass Valve is energized. Either of these conditions prevents a high vibration trip.

4.1 Inside DG1 Control Panel, remove cover from Vibraswitch Control Unit DG-CBX-1.

4.2 Connect VOM, set to read 250 VDC, in Vibraswitch Control Unit across Relay TR-1, Terminals 3(-) and 7(+) (refer to Attachment 3, Figure 2).

4.3 Simultaneously start stopwatch when installing jumper in Step 4.4 and stop stopwatch when TR-1 picks up (~ 30 seconds).

4.4 (Concurrent Verification) Install a jumper in Vibraswitch Control Unit between Terminals 22 and 23, and verify following:

Performed By: _________

Verified By: _________

4.4.1 Relay TR-1 picks up in 30 seconds as verified by VOM reading ~ 125 VDC.

4.4.2 Record ACTUATION TIME on Attachment 1.

4.5 Connect VOM, set to read 250 VDC, in Vibraswitch Control Unit across Terminals 17(+) and 18(-). Ensure ~ 125 VDC is present.

4.6 Simultaneously start stopwatch when installing jumper in Step 4.7 and stop stopwatch when TR-2 picks up (~ 5 seconds).

4.7 (Concurrent Verification) Install a second jumper in Vibraswitch Control Unit between Terminals 3 and 4, and verify following:

Performed By: _________

Verified By: _________

4.7.1 Relay TR-2 picks up in 5 seconds as verified by VOM changing from ~ 125 VDC to 0 volts.

4.7.2 Record ACTUATION TIME on Attachment 1.

4.7.3 Local DG1 Control Panel Annunciator, EXCESSIVE VIBRATION, alarms.

4.7.4 Annunciator C-1/F-3, DIESEL GEN 1 EXCESSIVE VIBRATION, alarms.

4.7.5 Alarm VID displays 3605 DIESEL GEN 1 VIBRATION EXCESSIVE.

4.8 (Concurrent Verification) In Vibraswitch Control Unit, remove jumper from Terminals 3 and 4, and verify alarms remain in.

Performed By: _________

Verified By: _________

Examination Outline Cross-Reference	Level	RO
205000 (SF4 SCS) Shutdown Cooling Knowledge of the effect that a loss or malfunction of the SHUTDOWN COOLING SYSTEM (RHR SHUTDOWN COOLING MODE) will have on following: K3.05 Fuel pool cooling assist: Plant-Specific	Tier#	2
	Group#	1
	K/A #	205000 K3.05
	Rating	2.6
	Revision	0
Revision Statement:		

Question 19

The plant is in Mode 5 with the following conditions:

- RHR System B is intertied with Fuel Pool Cooling (FPC) to provide additional cooling to the Spent Fuel Pool (SFP).
- FPC Pump A is in service.
- RHR Pump B is in service.
- SFP temperature is 120°F.

A spurious Group 2 isolation is received.

(1) Which pump(s) trip(s) as a result of this condition?

AND

(2) Which procedure is required to be entered?

A. (1) FPC Pump A and RHR Pump B
(2) 2.4SDC [Shutdown cooling Abnormal]

B. (1) FPC Pump A and RHR Pump B
(2) 2.4FPC [Fuel Pool Cooling Trouble]

C. (1) RHR Pump B
(2) 2.4SDC [Shutdown cooling Abnormal]

D. (1) RHR Pump B
(2) 2.4FPC [Fuel Pool Cooling Trouble]

Answer: C
Explanation:

Connections to the RESIDUAL HEAT REMOVAL (RHR) system are provided which allow the RHR heat exchangers to be used to aid in cooling the fuel storage pool should supplementary cooling be necessary. The RHR system can be intertied with the Fuel Pool Cooling system when the Fuel Pool gates and slot plugs have been removed. With RHR Pump B operating in SDC, manual valve RHR-82 [RHR System Return to FPC System] is opened to supply a portion of RHR flow to the FPC distribution header. This capability increases the spent fuel pool cooling capacity in the event that additional capacity is necessary to maintain fuel pool temperature below 150°F. The RHR system - Fuel Pool Cooling system intertie is sized to assist with removing the decay heat of a full core off-load plus the spent fuel discharged from previous refuelings.

In the event that that RHR Assist mode of cooling is being utilized, weirs are adjusted to make reactor cavity water flow into skimmer surge tanks and prevent fuel pool water from flowing into skimmer surge tanks. Configuring weirs in this fashion allows skimmer tanks to only be taking suction off of the Reactor well. This alignment will force more circulation from the fuel pool into the reactor well. RHR Pump B is providing both shutdown cooling and fuel pool cooling assist in this alignment.

A Group 2 isolation causes RHR SDC suction valves RHR-MO17 & 18 to close. This results in automatic trip of RHR Pump B due to loss of suction path. FPC Pump A will remain in operation, with the return path to the FPC skimmer surge tank via the reactor cavity weirs.

Trip of the operating RHR pump in SDC is an entry condition to procedure 2.4SDC. Since FPC Pump A remains in operation and SFP temperature is <125°F, no entry condition to procedure 2.4FPC exists.

Distracters:

Answer A part 1 is plausible to the examinee who knows RHR Pump B will trip when SDC suction valves close and believes that would result in loss of return flow to the FPC skimmer surge tank and a low skimmer surge tank level trip of FPC Pump A. The examinee who only considers loss of RHR flow to the SFP and does not consider RHR SDC suction flow from the RPV is also terminated may choose this answer. It is wrong because FPC flow continues from the skimmer surge tanks to FPC Pump A, into the SFP and reactor cavity, and return to the skimmer surge tanks; therefore, FPC Pump A remains running. Part 2 is correct.

Answer B part 1 is plausible and wrong for the same reason as given for distractor A. Part 2 is plausible because RHR is in fuel pool cooling assist when it is lost, and that will cause SFP temp to eventually rise. It is wrong because entry conditions for 2.4SPC are trip of all FPC pumps, SFP temperature >125°F, or loss of cooling to FP heat exchangers, none of which exist.

Answer D part 1 is correct. Part 2 part 1 is plausible and wrong for the same reason as given for distractor B.

Technical References: Procedure 2.2.69.2 [RHR System Shutdown Operations](Rev 106), Lesson plan COR001-06-01 [Fuel Pool Cooling](Rev 31), procedure 2.1.22 [Recovering from a Group Isolation](Rev 63), procedure 2.4SDC [Shutdown Cooling Abnormal](Rev 17), procedure 2.4FPC [Fuel Pool Cooling Trouble](Rev 37)		
References to be provided to applicants during exam: none		
Learning Objective: COR002-23-02 Obj LO 7g, Given a specific RHR system malfunction, determine the effect on any of the following: Fuel Pool Cooling assist		
Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(4),(7)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA Applicability:		
Top 10 Risk Significant System - RHR		

J. Fuel Pool Cooling Assist from RHR

SO-10b
LO-5b
Fig 4

1. When the fuel pool temperature is approaching 150EF, the Control Room operators have the option of cross-tying either loop of RHR to FPC. This is most likely to happen when the core is off-loaded to the fuel pool during refueling operations when the Fuel Pool gates and slot plugs have been removed. Should the RHR fail during this time, the fuel pool temperature would rise and an alternate means of cooling would have to be made available. Otherwise the Reactor Building would be evacuated, the Standby Gas Treatment system put into operation, and the fuel pool would be allowed to boil. An alternate means of making up inventory to the fuel pool would then be implemented.

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Lesson Title:	Fuel Pool Cooling		
Lesson Number:	COR001-06-01	Revision:	32

The RHR system can be intertied with the Fuel Pool Cooling system when the Fuel Pool gates and slot plugs have been removed. This capability increases the spent fuel pool cooling capacity in the event that additional capacity is necessary to maintain fuel pool temperature below 1501F. The RHR system - Fuel Pool Cooling system intertie is sized to assist with removing the decay heat of a full core off-load plus the spent fuel discharged from previous refuelings. It is concluded that Power Generation Design Basis 3 is satisfied by this arrangement. (See USAR Section X-5, "Fuel Pool Cooling and Demineralizer System.")

Fig 6	b.	The skimmer wells, or scuppers, act like gutters to remove water in the pool in excess of what can be controlled by the weirs. Water that overflows into the skimmer wells is piped into the skimmer surge tanks. Skimmer wells are located on the fuel pool south wall only.
	c.	In the event that that RHR Assist mode of cooling is being utilized, weirs are adjusted to make reactor cavity water flow into skimmer surge tanks and prevent fuel pool water from flowing into skimmer surge tanks. Configuring weirs in this fashion allows skimmer tanks to only be taking suction off of the Reactor well. This alignment will force more circulation from the fuel pool into the reactor well.
Fig 6 LO-05f; 09c SO-10f; 13a	4.	Ventilation ducts are located around the perimeter of all three pools at an elevation just above that of the skimmer wells. Their purpose is to evacuate air from directly over the surface of the pools to keep airborne radiation levels to a minimum and to keep the refueling floor relative humidity as low as possible. The ventilation ducts are connected to the Reactor Building Exhaust Ventilation system (or the Standby Gas Treatment system when the ventilation system is isolated). Drains from the ventilation ductwork are routed to the 4th floor equipment drains.

Lesson Title:	Fuel Pool Cooling		
Lesson Number:	COR001-06-01	Revision:	32

15. FUEL POOL COOLING SYSTEM INTERTIE USING EITHER RHR SUBSYSTEM

15.1 PLACING FUEL POOL COOLING SYSTEM INTERTIE IN SERVICE

15.1.1 Notify Radiation Protection prior to beginning section.

15.1.2 This section shall only be performed when RHR operating in SDC Mode.

15.1.3 Ensure one of following:

15.1.3.1 RHR Subsystem B in SDC Mode of operation.

15.1.3.2 RHR Subsystem A in SDC using intersystem crosstie to RHR Loop B.

15.1.4 Ensure fuel pool gates removed.

NOTE – Running at least one FPC/ADHR pump is not required, but desirable to minimize thermal stratification.

15.1.5 If available, ensure at least one FPC/ADHR pump running but no more than two per Procedure 2.2.32.

15.1.6 IF FPC System will be secured (i.e., no cooling), THEN ensure requirements of Procedure 2.1.20.2 met for alternate spent fuel pool cooling.

15.1.7 While maintaining skimmer surge tank level between high and low level alarm setpoints, perform following:

15.1.7.1 Mark original location of fuel pool and reactor cavity weirs.

NOTE – Weirs are adjusted to make reactor cavity water flow into skimmer surge tanks and prevent fuel pool water from flowing into skimmer surge tanks.

15.1.7.2 Slowly lower reactor cavity weirs and raise fuel pool weirs so reactor cavity weirs ~ 1" below fuel pool weirs.

NOTE – Step 15.1.8 will require two or more Operators.

15.1.8 IF one or two FPC/ADHR pumps running, THEN perform following:

NOTE – Channel 1 displays FPC/ADHR flow to Fuel Pool. Channel 2 displays FPC/ADHR flow to cavity.

15.1.8.1 Note flow on FPC-FI-01, FPC TO FUEL POOL AND RX CAVITY INDICATOR, CH 1 (R-958 near ADHR HX Room on LRP-PNL-25-16-5, FPC/ADHR INSTRUMENTS).

Channel 1 Flow: ________

15.1.8.2 Maintain discharge pressure ~ 120 to 140 psig on following operating pumps during performance of Step 15.1.8.3.

- FPC-PIS-69A, FUEL POOL COOL PUMP A DISCH (R-958-NW on LR-25-16).
- FPC-PIS-69B, FUEL POOL COOL PUMP B DISCH (R-958-NW on LR-25-16).
- FPC-PIS-69C, FPC PUMP C DISCH PRESS IND SW (R-958-W on LRP-PNL-25-16-3).
- FPC-PIS-69D, FPC PUMP D DISCH PRESS IND SW (R-958-W on LRP-PNL-25-16-4).

15.1.8.3 Perform following concurrently:

a. Slowly close FPC-30, FUEL STORAGE POOL RECIRC (R-958-N).

b. Slowly open FPC-33, RX WELL RECIRC (R-958-N).

15.1.8.4 Check flow on FPC-FI-01, FPC TO FUEL POOL AND RX CAVITY INDICATOR, CH 2, to be approximately the same as noted in Step 15.1.8.1 (R-958 near ADHR HX Room on LRP-PNL-25-16-5, FPC/ADHR INSTRUMENTS).

15.1.9 IF no FPC/ADHR pumps running, THEN perform following:

15.1.9.1 Close FPC-30, FUEL STORAGE POOL RECIRC (R-958-N).

15.1.10 At Panel 9-3, observe RHR Subsystem B flow on RHR-FR-143, RHR FLOW.

<u>NOTE</u> – Step 15.1.11 establishes ~ 1000 gpm through RHR-82 to ensure adequate flow to spent fuel pool.

15.1.11 While maintaining skimmer surge tank level between high and low level alarm setpoints, perform following:

15.1.11.1 Adjust RHR Subsystem B flow to ~ 6000 gpm.

15.1.11.2 Slowly open RHR-82, RHR SYSTEM RET. TO FPC SYSTEM (R-958-SW), until full open.

15.1.12 At Panel 9-3, adjust following valves to maintain approximate SDC flow established in Step 15.1.11.2, and reactor coolant and fuel pool temperature ≥ 75°F:

15.1.12.1 RHR-MO-27B, OUTBD INJECTION VLV.

15.1.12.2 IF RHR Subsystem B in SDC Mode of operation:

a. RHR-MO-66B, HX BYPASS VLV.

b. RHR-MO-12B, HX-B OUTLET VLV.

5.2 Upon full Group 2 Isolation, ensure following actions have occurred:

5.2.1 If RHR in Shutdown Cooling, running RHR pump has tripped.

5.2.2 Following valves have closed:

NOTE – All valve positions can be determined from containment mimic on Panel 9-3 unless otherwise specified.

5.2.2.1 RHR-SSV-95 (Div 1), RHR SAMPLE VALVE.

5.2.2.2 RHR-SSV-96 (Div 1), RHR SAMPLE VALVE.

5.2.2.3 RHR-SSV-60 (Div 2), RHR SAMPLE VALVE.

5.2.2.4 RHR-SSV-61 (Div 2), RHR SAMPLE VALVE.

5.2.2.5 RHR-MO-57 (Div 1), RHR DISCH TO RW OUTBD VLV.

5.2.2.6 RHR-MO-67 (Div 2), RHR DISCH TO RW INBD VLV.

5.2.2.7 RW-AO-83 (Div 2), DISCH VLV.

5.2.2.8 RW-AO-82 (Div 1), DISCH ROOT VLV.

5.2.2.9 RW-AO-95 (Div 2), DISCH VLV, if PASS sampling on sump not in-progress.

5.2.2.10 RW-AO-94 (Div 1), DISCH ROOT VLV, if PASS sampling on sump not in-progress.

5.2.2.11 Channel A TIP BALL VALVE.

5.2.2.12 Channel B TIP BALL VALVE.

5.2.2.13 Channel C TIP BALL VALVE.

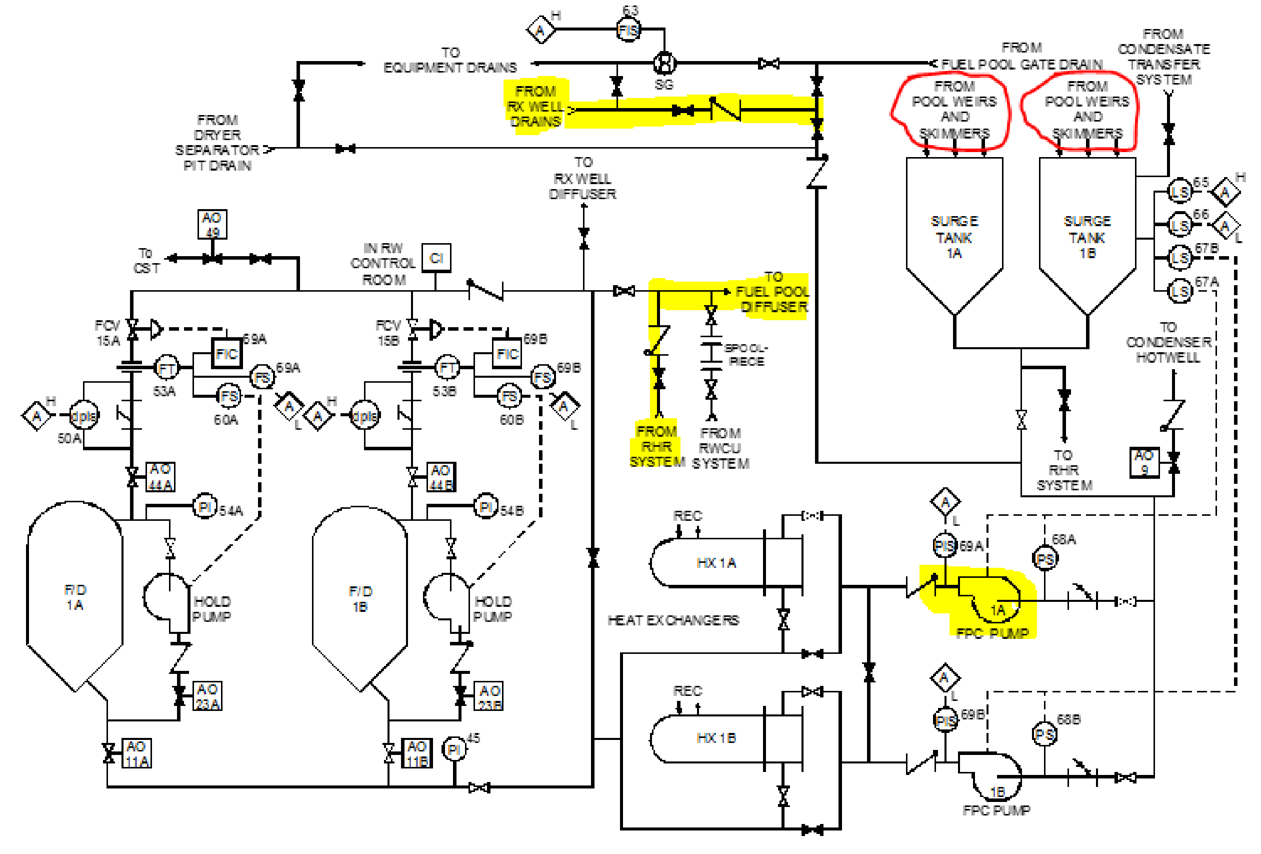
5.2.2.14 Channel D TIP BALL VALVE.

5.2.2.15 RHR-MO-17 (Div 1), SHUTDOWN COOLING RHR SUPPLY OUTBD VLV, if RHR in Shutdown Cooling.

5.2.2.16 RHR-MO-18 (Div 2), SHUTDOWN COOLING RHR SUPPLY INBD VLV, if RHR in Shutdown Cooling.

5.2.2.17 RHR-MO-25A (Div 1), INBD INJECTION VLV (Panel 9-3 Benchboard), if RHR in Shutdown Cooling.

5.2.2.18 RHR-MO-25B (Div 2), INBD INJECTION VLV (Panel 9-3 Benchboard), if RHR in Shutdown Cooling.



FUEL POOL COOLING and DEMINERALIZER SYSTEM
Figure 4, Rev. 2
COR001-06

CNS OPERATIONS MANUAL ABNORMAL PROCEDURE 2.4SDC SHUTDOWN COOLING ABNORMAL	USE: CONTINUOUS QUALITY: QAPD RELATED EFFECTIVE: 2/13/19 APPROVAL: ITR-RDM OWNER: OSG SUPV DEPARTMENT: OPS

1. ENTRY CONDITIONS
   - 1.1 Reduction in RPV cooldown rate.
   - 1.2 Rise in RPV pressure while in SDC.
   - 1.3 Lowering RPV water level while in SDC.
   - 1.4 Operating RHR pump trip while in SDC.
2. AUTOMATIC ACTIONS
   - 2.1 If PCIS Group 2 or 72 psig high pressure isolation has occurred:
     - 2.1.1 RHR-MO-17, SHUTDOWN COOLING RHR SUPPLY OUTBD VLV, closes.
     - 2.1.2 RHR-MO-18, SHUTDOWN COOLING RHR SUPPLY INBD VLV, closes.
   - 2.2 If PCIS Group 2 has occurred, RHR-MO-25A and/or RHR-MO-25B, INBD INJECTION VLV(s), close.
3. IMMEDIATE OPERATOR ACTION

CNS OPERATIONS MANUAL ABNORMAL PROCEDURE 2.4FPC FUEL POOL COOLING TROUBLE	USE: CONTINUOUS QUALITY: QAPD RELATED EFFECTIVE: 1/9/19 APPROVAL: ITR-RDM OWNER: OSG SUPV DEPARTMENT: OPS

1. ENTRY CONDITIONS

   1.1 Fuel pool water temperature ≥ 125°F.

   1.2 Loss of all FPC pumps.

   1.3 Loss of cooling flow to FPC heat exchangers.

2. AUTOMATIC ACTIONS

   2.1 Fuel Pool Cooling Pumps A through D trip on either of following:

      2.1.1 Low suction pressure of -10' H_2O.

      2.1.2 Surge tank low level of 50 cu ft.

   2.2 Filter demineralizer goes into hold when flow < 120 gpm.

3. IMMEDIATE OPERATOR ACTIONS

   3.1 None.

Examination Outline Cross-Reference	Level	RO
212000 (SF7 RPS) Reactor Protection Ability to (a) predict the impacts of the following on the REACTOR PROTECTION SYSTEM; and (b) based on those predictions, use procedures to correct, control, or mitigate the consequences of those abnormal conditions or operations: A2.11 Main steamline isolation valve closure	Tier#	2
	Group#	1
	K/A #	212000 A2.11
	Rating	4.0
	Revision	0
Revision Statement:		

Question 20

With the plant at 15% power, MSIVs 80C AND 86D simultaneously FAST close.

Which one of the following describes the effect of this condition on RPS AND which procedure(s) is/are required to be entered?

A. Full reactor scram; enter 2.1.5 [Reactor Scram] AND EOP-1A

B. RPS half scram; enter 2.4MSIV [Inadvertent MSIV Closure], ONLY

C. Contacts open in RPS but logic for half scram on MSIV position is NOT satisfied, so NO trip is initiated; enter 2.4MSIV [Inadvertent MSIV Closure], ONLY

D. Contacts open in RPS and logic for RPS half scram on MSIV position is satisfied but is bypassed in RPS for current plant Mode; enter 2.4MSIV [Inadvertent MSIV Closure], ONLY

Answer: B

Explanation:
At 15% power, the Reactor Mode Switch is in RUN. MSIV closure RPS trip is only active (not bypassed) when the Reactor Mode Switch is in RUN. This question represents isolation of two of the four MSLs. If two steam lines are isolated a RPS protective action may or may not occur, depending on the MSIV's that are closed. If the isolation valves for Main Steam Lines "A" and "D", or, "B" and "C" are closed 10%, the RPS recognizes this condition but no actions are initiated until a third line isolates causing a full reactor scram to take place. If the isolation valves are closed on two Main Steam Lines using any other combination, a half scram will occur. Isolation of MSL (A and B) OR (C and D) trip RPS A. Isolation of MSL (A and C) OR (B and D) trip RPS B. In this case, isolation of MSLs C and D causes a RPS A half scram. Also, isolation of two MSLs at 15% power does not cause RPV pressure to rise to the

scram setpoint or steam flow in the two MSLs that remain open to rise to the high flow isolation setpoint, since the two MSLs that remain open can easily accommodate 15% steam flow. Therefore, a full scram is not generated, and neither procedure 2.1.5 nor EOP-1A will be entered.

Only Procedure 2.4MSIV is required to be entered, since it is intended to mitigate a MSIV closure event that does not directly result in a scram.

Distracters:
Answer A is plausible because some combinations of closed MSIVs result in a reactor scram and because it would be correct at high power levels. When an MSIV closes, steam flow in the open steam lines increases to accommodate the steam flow lost from the line that closed. The Group 1 isolation setpoint for MSL Flow High is 142.7% of rated steam flow. At power levels above 75%, when two MSIVs close and all flow from those steam lines must redirect through the two lines that remain open, the steam flow in each of the open steam lines approaches 200% of their normal rated flow. Therefore, a Group 1 isolation occurs, resulting in closure of all eight MSIVs. Closure of MSIVs in more than one MSL results in a direct full scram signal to RPS when the MSIVs reach not fully open position. Isolation of two MSLs at 100% power also results in RPS trip signals on high reactor pressure and high APRM flux. The RPS setpoint for low reactor water level, +3 inches, is also exceeded due to shrink during the scram. Procedure 2.1.5 entry would be required and contains mitigating actions required to be performed. EOP-1A entry would be required due to high reactor pressure and low reactor water level and contains required actions for level and pressure control with MSIVs closed. This answer is wrong because isolation of the subject MSIVs does not directly result in a trip of both RPS A and B and because at 15% power, the two MSLs that remain open can easily accommodate the required steam flow, so a scram signal is not generated. The examinee who believes a scram will occur and knows 2.4MSIV is not intended for MSIV closures that directly result in an RPS actuation will choose this answer. This answer is wrong because isolation of the subject MSIVs does not directly result in a trip of RPS A and B, so neither procedure 2.1.5 nor EOP-1A entry is required.

Answer C is plausible other combinations of two MSIVs closing would result in only contacts in RPS logic opening, but no half scram. Isolation of MSL (A and D) OR (B and C) would not result in a half scram. It is wrong for the same reason given for distractor C.

Answer D is plausible because MSIV closure RPS trip is bypassed when the Reactor Mode Switch is not in RUN. It is wrong because the Reactor Mode Switch wouold be in RUN at 15% power, and closure of the subject MSIVs would result in an RPS A half scram.

Technical References: Procedure 2.4MSIV [Inadvertent MSIV Closure](Rev 10), procedure 2.1.5 [Reactor Scram](Rev 77), EOP-1A [RPV Control](Rev 22), Lesson plan COR002-21-02 [Ops Reactor Protection System](Rev 25)

References to be provided to applicants during exam: none		
Learning Objective: COR002-21-02 Obj LO-12a, Given plant conditions determine if: A Full Scram should have occurred		
Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(6)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA Applicability:		
Top 10 Risk Significant System - RPS		

The setpoint for this reactor scram, as with the turbine stop valve closure scram, is ≤ 10% valve closure from the full open position.

a. There are four Main Steam Lines with two isolation valves per line, one inside and one outside the drywell. Each valve is provided with a position switch mounted on the valve which supplies control signals to one RPS auto scram channel. The position switches will open contacts in their respective RPS auto scram channel if the associated valve were to close 10% of its stroke from the fully open position.

Fig 7

Since there are eight position switches which feed four RPS channels, they are arranged in such a way that if three or four Main Steam Lines were to be isolated (one valve closed more than 10% in each line) a reactor scram would occur. Isolation of only one Main Steam Line will have no effect on RPS operation. This allows for the individual testing of MSIV's during power operations without effecting reactor operation.

Lesson Number: COR002-21-02	Revision: 25

If two steam lines are isolated a RPS protective action may or may not occur, depending on the MSIV's that are closed. If the isolation valves for Main Steam Lines "A" and "D", or, "B" and "C" are closed 10%, the RPS recognizes this condition but no actions are initiated until a third line isolates causing a full reactor scram to take place. If the isolation valves are closed on two Main Steam Lines using any other combination, a half scram will occur.

LO-04j, 12d

b. The MSIV closure scram is bypassed any time the Reactor Mode Switch is in any other position other than "RUN". This bypass allows for all four steam lines to be isolated and the reactor to be operated in a hot standby condition at low power levels. This condition occurs during reactor startups and certain reactivity tests during refueling.

CNS OPERATIONS MANUAL ABNORMAL PROCEDURE 2.4MSIV INADVERTENT MSIV CLOSURE	USE: CONTINUOUS QUALITY: QAPD RELATED EFFECTIVE: 1/18/17 APPROVAL: ITR-RDM OWNER: OSG SUPV DEPARTMENT: OPS

1. ENTRY CONDITIONS

1.1 MSIV indicates closed on Panel 9-3.

1.2 All of following:

1.2.1 Higher than normal steam flow in other main steam lines.

1.2.2 Reactor pressure rises.

1.2.3 Power level rises.

2. AUTOMATIC ACTIONS

2.1 None.

3. IMMEDIATE OPERATOR ACTIONS

3.1 None.

4. SUBSEQUENT ACTIONS

4.1 Record current time and date. Time/Date: ________/________

NOTE – Steps 4.2 and 4.3 may be performed concurrently.

4.2 Perform Rapid Power Reduction per Procedure 2.1.10 to < 75% RTP.

4.3 Place control switch for affected MSIV(s) to CLOSE.

4.4 IF only one line is isolated or conditions did not result in a scram, THEN maintain MSIV(s) closed until Engineering Evaluation has been performed. ⦿[1]

NOTE – MS-MO-78, OUTBD THROTTLE VLV, stroke time is ~ 24 seconds.

4.5 Ensure main steam line drain is in service as follows (PNL 9-4):

4.5.1 Ensure MS-MO-79, RO BYPASS VLV, is closed.

4.5.2 Throttle open MS-MO-78, OUTBD THROTTLE VLV, to intermediate position.

4.5.3 Fully open MS-MO-78, OUTBD THROTTLE VLV.

4.5.4 Open MS-MO-77, OUTBD ISOL VLV.

ATTACHMENT 1 INFORMATION SHEET

ATTACHMENT 1 INFORMATION SHEET

1. DISCUSSION

1.1 If reactor is operating at > 75% power, following may occur:

1.1.1 Remaining MSIVs may close on high steam flow causing reactor scram.

1.1.2 High reactor pressure scram at ≤ 1050 psig.

1.1.3 High flux scram due to small but rapid pressure transient.

1.1.4 Low-Low Set will actuate upon coincident signals of reactor high pressure scram and any relief valve open.

1.2 The intent of this procedure is to address events where a MSIV(s) closed, but no scram occurs. It is not intended to address MSIV closures with scram or Group 1 isolations. Other procedures address these conditions (e.g., Alarm Procedure 2.3_9-5-2 for MSIV NOT FULL OPEN TRIP directs the user to Procedure 2.1.5 if a scram occurs and Alarm Procedure 2.3_9-5-1 for Group 1 isolations directs the user to Procedures 2.1.5 and 2.1.22). Note that Procedure 2.3_9-5-2 for MSIV NOT FULL OPEN TRIP also directs the user to Procedure 2.4MSIV if no scram occurred.

1.3 Closure of one MSIV during power operation is required for surveillance testing. Therefore, the Reactor Protection System logic from the VALVE POSITION switches permits full closure of any MSIV without initiating a half scram. Surveillance procedure for such a test requires an initial power reduction.

1.4 GE SIL-404 identifies that with main steam lines sharing a common drain header upstream of a restricting orifice, an idle steam line will not drain due to a 20 to 50 psid difference between idle and flowing steam lines. This may result in steam flow into the idle steam line through the drain header, which prevents condensate in the idle steam line from draining, forming water slugs. Subsequent restoration of the idle steam line could potentially result in water hammer and must be evaluated by Engineering prior to restoration.

1.5 The closure of a MSIV could be the result of:

1.5.1 MSIV stem/disc failure.

1.5.2 Loss of pneumatic supply to MSIV accumulators.

1.6 PROBABLE ANNUNCIATORS

1.6.1 9-5-2/B-2, MSIV NOT FULL OPEN TRIP.

1.6.2 9-5-2/A-1, RX SCRAM CHANNEL A.

1.6.3 9-5-2/A-3, RX SCRAM CHANNEL B.

Fig 3

LO-10c

4. Main Steam Isolation Valve (MSIV) - Closure

The MSIV closure scram is provided to anticipate the pressure and neutron flux transients that will occur during reactor operation if the MSIV's should close. The scram limits the release of fission products and anticipates the complete loss of the normal heat sink and subsequent over-pressurization transient.

The setpoint for this reactor scram, as with the turbine stop valve closure scram, is ≤ 10% valve closure from the full open position.

a. There are four Main Steam Lines with two isolation valves per line, one inside and one outside the drywell. Each valve is provided with a position switch mounted on the valve which supplies control signals to one RPS auto scram channel. The position switches will open contacts in their respective RPS auto scram channel if the associated valve were to close 10% of its stroke from the fully open position.

Fig 7

Since there are eight position switches which feed four RPS channels, they are arranged in such a way that if three or four Main Steam Lines were to be isolated (one valve closed more than 10% in each line) a reactor scram would occur. Isolation of only one Main Steam Line will have no effect on RPS operation. This allows for the individual testing of MSIV's during power operations without effecting reactor operation.

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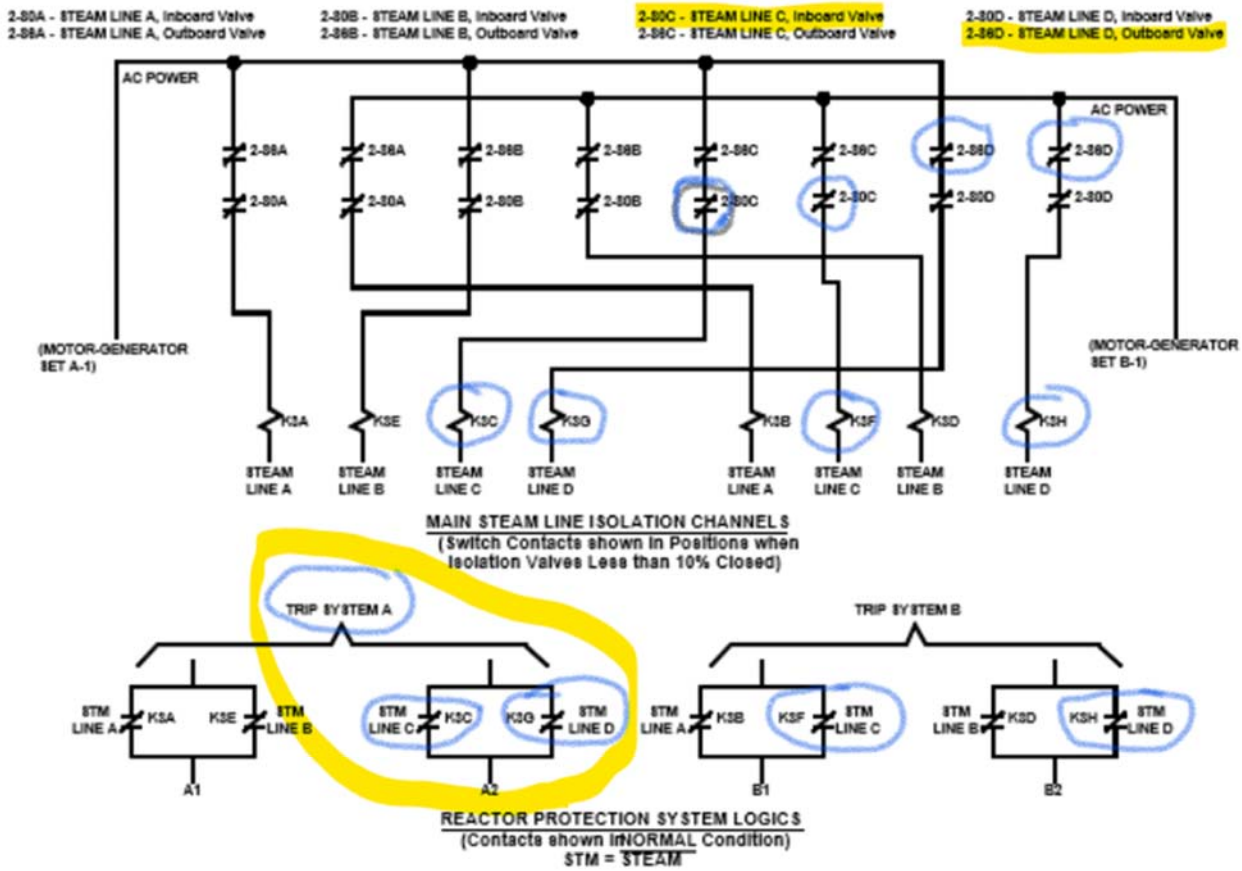
Lesson Number: COR002-21-02	Revision: 25

If two steam lines are isolated a RPS protective action may or may not occur, depending on the MSIV's that are closed. If the isolation valves for Main Steam Lines "A" and "D", or, "B" and "C" are closed 10%, the RPS recognizes this condition but no actions are initiated until a third line isolates causing a full reactor scram to take place. If the isolation valves are closed on two Main Steam Lines using any other combination, a half scram will occur.



MSIV CLOSURE SCRAM (Configuration)
Figure 7, Rev. 5
COR002-21-02

mapp\figures\cor002\cor00221\fig7.rlC CX/6/2/43

Examination Outline Cross-Reference	Level	RO
217000 (SF2, SF4 RCIC) Reactor Core Isolation Cooling Knowledge of the effect that a loss or malfunction of the following will have on the REACTOR CORE ISOLATION COOLING SYSTEM (RCIC): K6.01 Electrical power	**Tier#**	2
	Group#	1
	K/A #	217000 K6.01
	Rating	3.4
	Revision	0
Revision Statement:		

Question 21

The plant is at 100% power.

125 VDC Panel AA2 power is lost.

Then, a condition requiring automatic RCIC initiation occurs.

Which one of the following describes the effect of the loss of 125 VDC Panel AA2 on:

RCIC-MO-131 [Steam Supply to Turbine Valve] and RCIC flow controller RCIC-FIC-91?

A. RCIC-MO-131 automatically opens.
RCIC flow controller will NOT control in AUTO or in MANUAL.

B. RCIC-MO-131 automatically opens.
RCIC flow controller will NOT control in AUTO but will control in MANUAL.

C. RCIC-MO-131 remains closed but can be opened using its control switch.
RCIC flow controller will NOT control in AUTO or in MANUAL.

D. RCIC-MO-131 remains closed but can be opened using its control switch.
RCIC flow controller will NOT control in AUTO but will control in MANUAL.

Answer: C
Explanation: 125 VDC Panel AA2 supplies power to RCIC initiation logic and to the RCIC flow control circuit. RCIC initiation logic is energize to trip. With 125 VDC Panel AA2 de-energized, RCIC initiation will not occur; therefore, RCIC-MO-131 will remain closed, its standby position. The RCIC flow control circuit responds to RCIC flow feedback to position the RCIC governor valve. When RCIC is idle, flow feed back is zero, and RCIC governor valve is open. Upon a normal RCIC start, the ramp generator in the flow control circuit applies a closed signal to RCIC governor valve to prevent RCIC

overspeed by allowing the flow control circuit and control oil pressure to develop in response to rising flow feedback. This signal is ramped up to a high end stop, and RCIC flow controller assumes control as its output lowers in response to rising flow feedback. With the RCIC flow control circuit de-energized, no flow control signal is developed to close the governor valve. RCIC governor valve is fully open and the ramp generator function does not limit the RCIC control signal. RCIC flow controller RCIC-FIC-91 will not function in AUTO and cannot be placed into MANUAL, since it has no power. If RCIC-MO-131 is opened using its control switch, RCIC will overspeed, since the governor valve is fully open and there is no control signal to cause it to throttle closed.

Distracters:
Answer A is plausible because another 125 VDC panel, BB2, supplies some sensors and relays that input into RCIC isolation logic. An examinee may confuse isolation logic with initiation logic believe initiation will still occur from Div 2 powered sensors/logic. It is also plausible because flow controllers have some failure modes that prevent automatic operation but do not inhibit manual operation. It is wrong because Panel AA2 supplies the main circuit power to the RCIC initiation logic, which is energize to initiate, so RCIC-MO-131 will not receive an automatic open signal. It is also wrong because Panel AA2 supplies power to the RCIC flow controller, so it cannot be placed into MANUAL.

Answer B is plausible because RCIC-MO-131 will not automatically open and because power from Panel BB2 supplies a portion of RCIC logic. It is also plausible because flow controllers have some failure modes that prevent automatic operation but do not inhibit manual operation. If Panel AA2 only supplied the flow feedback portion of the flow control circuit, the controller would not function in AUTO but could be operated to control RCIC speed/flow in MANUAL. An examinee who does not know the power supply arrangement for RCIC may choose this answer. It is wrong for the same reason given for distractor A.

Answer D is correct with respect to RCIC-MO-131. It is plausible and wrong for the reasons given for distractor B with respect to RCIC flow controller.

Technical References: Lesson plan COR002-18-02 [Ops Reactor Core Isolation Cooling](Rev 31), GE dwgs. 791E264 sheets 02, 03, 04

References to be provided to applicants during exam: none

Learning Objective: COR002-18-02 Obj LO-10b, Predict the consequences of the following on the RCIC System: AC and/or DC Electrical power failure

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X

Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(7)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA Applicability:		
Top 10 Risk significant System - RCIC		

Lesson Number: COR002-18-02	Revision: 31

2. 125V DC Panel AA2

   Provides power to the RCIC flow controller and flow indicator, 505 Governor Control Panel, test circuit logic, remote turbine trip, Channel A isolation logic, and initiation logic. A loss of AA2 would result in the following problems:

   a. No initiation since power lost to Relay 13A-K2 which opens MO-131.

   b. No isolation since power lost to Relays K15, K16, and K17.

   c. No high-level trip due to loss of K38x which is in the MO-131 close circuit.

   d. Loss of remote turbine trip due to loss of K8.

3. 125V DC Panel AA3

   Provides 125V DC to outboard steam isolation valve (MO-16).

4. 125V DC Panel BB2

   Provides power to Channel B isolation logic (K30, 31, and 34) and Channel B High-Level Trip Logic Relay K34.

5. 250V DC RCIC Starter Rack

   Provides power to the following loads:

   a. Condensate Pump

   b. Vacuum Pump

6. NBPP

   Provides power to the following loads:

   a. RCIC pump suction and discharge indicators

   b. RCIC turbine steam inlet and exhaust pressure indicators

   c. RCIC Test Controller, RCIC-SIC-100

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From GE dwg. 791E264 sh 2

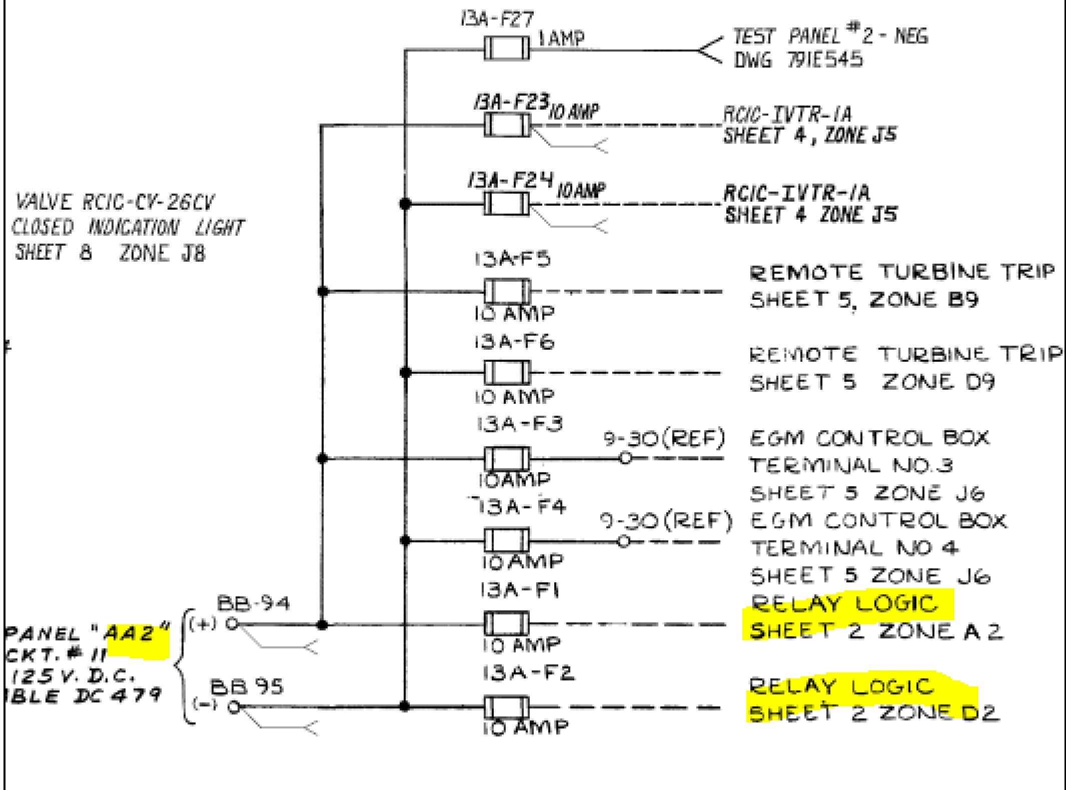
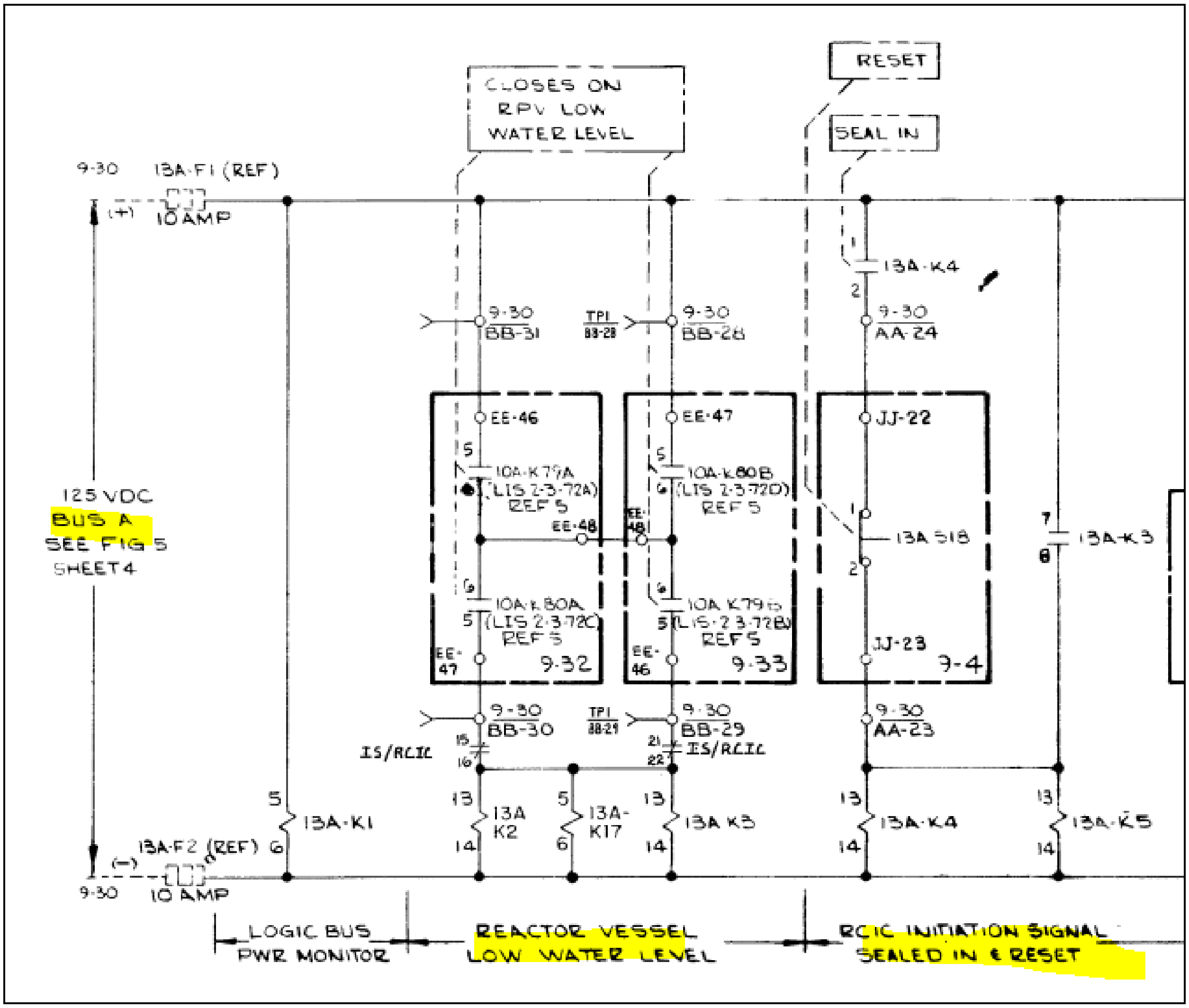
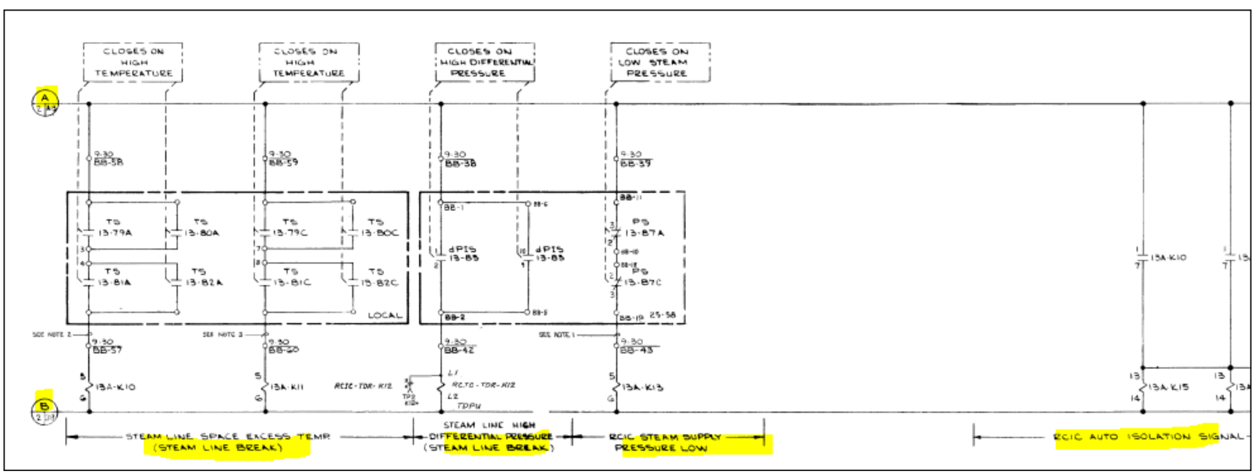


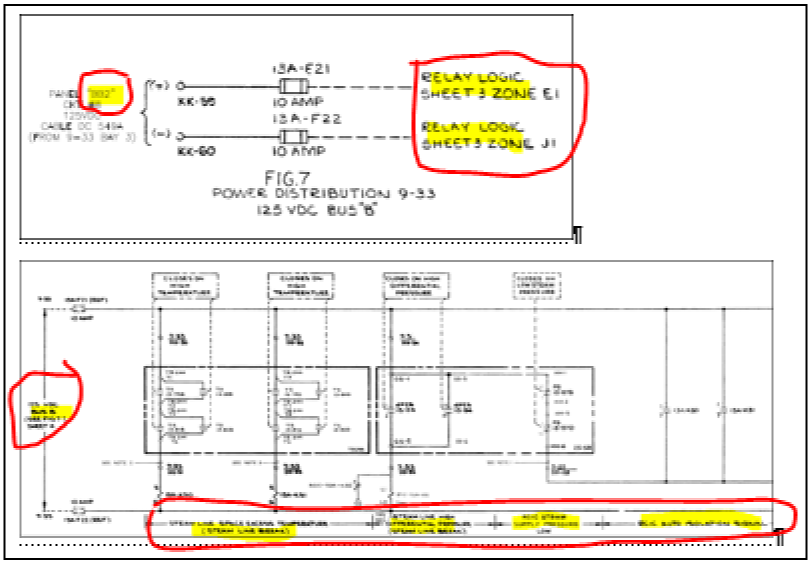
FIG 5
POWER DISTRIBUTION 9-30
125VDC BUS "A"

From GE dwg. 791E264 sh 3





From GE dwg. 791E264 sh 2 and 4



Examination Outline Cross-Reference	Level	RO
264000 (SF6 EGE) Emergency Generators (Diesel/Jet) EDG Ability to monitor automatic operations of the EMERGENCY GENERATORS (DIESEL/JET) including: A3.06 Cooling water system operation	Tier#	2
	Group#	1
	K/A #	264000 A3.06
	Rating	3.1
	Revision	0
Revision Statement:		

Question 22

The plant is at 100% power.

Service Water pumps A and B Mode Selector switches are in AUTO.

Service Water pumps C and D Mode Selector switches are in STDBY.

A design basis LOCA with Loss of Offsite Power occurs.

Assuming the design criteria MAXIMUM times listed in the USAR, which one of the following completes the statement below regarding DG load sequencing?

Service Water pumps ____(1)____ start ____(2)____ seconds **following bus re-energization**?

A. (1) A and B
(2) 5

B. (1) A and B
(2) 13

C. (1) C and D
(2) 5

D. (1) C and D
(2) 13

Answer: D

Explanation:
This question is a modified version of 9/2018 ILT NRC Q#50. It was modified by adding part 1, to test knowledge of the SW pump standby start logic, and by changing

part to to SW Pump sequence time from bus re-energization versus from LOOP/LOCA signal.

Service Water pumps cool DG1 and DG2. The DGs are designed to re-energize their respective buses within 14 seconds of a LOOP/LOCA signal. DGs are cooled by SW Pumps. At 100% power, normally two SW pumps are selected to STANDBY. Service Water Pumps that are in STANDBY will automatically sequence 13 seconds following DG output breaker closure during a LOOP/LOCA.

Distracters:
Answer A part 1 is plausible because SW pumps A and B switch positions are AUTO. Pumps in AUTO start on low SW discharge header pressure. An examinee who does not know SW pump logic may believe AUTO means the SW pumps would automatically start on a LOOP/LOCA signal. This is plausible because SGT fans in AUTO start on an initiation signal, and SGT fans in STDBY will not automatically start on an initiation signal. It is wrong because only SW pumps in STDBY sequence on during a LOOP/LOCA. The low SW header pressure start signal is removed during load sequencing. Part 2 is plausible because the sequence time for RHR Pumps B and D sequence on after 5 seconds. It is wrong because SW Pumps selected to Standby sequence on after 13 seconds.

Answer B part 1 is plausible and wrong for the reason given for distractor A. Part 2 is correct.

Answer C part 1 is correct. Part 2 is plausible and wrong for the reason given for distractor A.

Technical References: lesson plans COR001-01-01 [Ops AC Electrical Distribution](Rev 50), procedure 2.2.20 [Standby AC Power System (Diesel Generator)](Rev 105), TS 3.8.1 [AC Sources – Operating], procedure 2.2.18.1 [4160V Auxiliary Power Distribution System](Rev 2)

References to be provided to applicants during exam: none

Learning Objective: COR001-01-01 Obj LO-13b,c - Predict the consequences of the following events on the AC Electrical Distribution System: Loss of Coolant Accident , Loss of Off-site Power

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	9/2018 ILT NRC Q#50
	New	

Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X

10CFR Part 55 Content:	55.41(b)(7)

Level of Difficulty:	2
SRO Only Justification:	N/A
PSA Applicability:	
Top 10 Risk Significant Systems – Emergency AC Power/DGs, Service Water	

9/2018 ILT NRC Q#50

Question → ·50¶

¶

The·plant·is·at·100%·power.¶

¶

A·design·basis·LOCA·with·Loss·of·Offsite·Power·occurs.¶

¶

¶

Assuming·the·design·criteria·MAXIMUM·times·listed·in·the·USAR,·which·one·of·the·following completes·the·statement·below·regarding·DG·load·sequencing?¶

¶

Pumps·which·supply·cooling·water·from·the·ultimate·heat·sink·to·DGs·start·_→_·seconds· **following·receipt·of·the·LOOP/LOCA·signal**?¶

¶

¶

A.→13·¶

¶

¶

B.→14·¶

¶

¶

C.→24·¶

¶

¶

D.→27·¶

¶

¶

¶

Answer:··D¤

ATTACHMENT 2 INFORMATION SHEET

2.4.7.7 When Relay 27X3/1F (27X3/1G) picks up, close signal is removed from automatic closing logic of Breaker EG-1 (EG-2).

2.4.7.8 When Relay 27X4/1F (27X4/1G) picks up, following actions occur:

a. A close signal is removed from the AUTO (low pressure) closing logic of SW Pumps A and C (B and D).

b. Time Delay Relays TDR/SWP1A and TDR/SWP1C (TDR/SWP1B and TDR/SWP1D) (13 seconds) start timing out and after the relays have timed out associated SW pump selected for standby will start.

c. Relay 27X6/1F (27X6/1G) picks up and Time Delay Relays TDR/RCC1A and TDR/RCC1B (TDR/RCC1C and TDR/RCC1D) (20 seconds) start timing out and after relays have timed out, associated REC pump selected for standby will start.

c. When Relay 10A-K4A (10A-K4B) picks up, following time delay relays start timing out:

   1. 10A-K70A (10A-K75B) (0 seconds).

   2. 10A-K75A (10A-K70B) (5 seconds).

d. When Relay 10A-K70A (10A-K75B) times out, it causes Relay 10A-K18A (10A-K21B) to pick up and this relay applies a close signal to the automatic closing logic of the RHR Pump A (D) breaker.

e. When Relay 10A-K75A (10A-K70B) times out, it causes Relay 10A-K21A (10A-K18B) to pick up and this relay applies a close signal to the automatic closing logic of RHR Pump B (C) breaker.

f. If a CS initiation signal is present and bus has been energized by Emergency Transformer, Relay 14A-K4A (14A-K4B) picks up and causes Time Delay Relay 14A-K16A (14A-K16B) (10 seconds) to start timing out.

g. When Relay 14A-K16A (14A-K16B) times out, it causes Relay 14A-K12A (14A-K12B) to pick up and this relay applies a close signal to the automatic closing logic of the CS Pump A (B) breaker.

ATTACHMENT 3 INFORMATION SHEET

1. DISCUSSION

1.1 FUNCTION

1.1.1 Diesel generators (DG1 and DG2) provide necessary power to safely shut down reactor with or without CSCS initiation and with a loss of off-site power. Off-site power is normally supplied from 161 kV System through startup transformer and from 69 kV System through emergency transformer.

1.2 OPERATING CHARACTERISTICS

1.2.1 Under emergency conditions, diesel generators will operate to supply their respective buses (DG1 supplies Bus 1F and DG2 supplies Bus 1G) independent of each other and all other power sources. They are designed to maintain their individual bus frequency at 60 Hz regardless of load applied.

1.2.2 Under normal conditions operability of diesel generators is tested by operating them in parallel with off-site power. This is Test Mode of operation. If power to Bus 1A(1B) from Normal and Startup Transformers is lost while diesel generator is in Test Mode, Breaker 1FA(1GB) will automatically open to separate Bus 1F(1G) from Bus 1A(1B).

1.2.3 Diesel generators are designed to start automatically and provide power to their respective buses within 14 seconds of receipt of auto start signal. To maintain this rapid start and loading capability, diesel generators are equipped with lube oil and jacket water pumps and heaters and a pre/post lube oil pump. These items keep engine in a pre-warmed condition.

1.2.4 Jacket water and lube oil temperature must be maintained ≥ 90°F to meet diesel generator fast start requirements.

1.2.5 Engine speed governor oil level is maintained visible above mark on sight glass. This level ensures oil level is maintained visible on sight glass during diesel operation, which ensures proper speed governor operation.

AC Sources - Operating
3.8.1

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.7	----------NOTE---------- All DG starts may be preceded by an engine prelube period. ---------- Verify each DG starts from standby condition and achieves, in ≤ 14 seconds, voltage ≥ 3950 V and frequency ≥ 58.8 Hz, and after steady state conditions are reached, maintains voltage ≥ 3900 V and ≤ 4400 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.8	----------NOTE---------- This Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify automatic and manual transfer of unit power supply from the normal offsite circuit to the alternate offsite circuit.	In accordance with the Surveillance Frequency Control Program

(continued)

Lesson Title: OPS AC Electrical Distribution	
Lesson Number: COR001-01-01	Revision Number: 50

TABLE 6

TYPICAL SEQUENTIAL LOADING OF DIESEL GENERATORS OR EMERGENCY TRANSFORMER

Event	Time (sec)*	Comment
Design basis loss of coolant starts, normal off-site power assumed lost.	-16	
Signal diesel generator to start from drywell high pressure or vessel low water level or loss of preferred a-c power source is processed.	-14	This sequence applies to one diesel and its associated loads. The other diesel has a similar sequence and load.
Diesel Generator ready to load. Start first RHR pump (LPCI Mode) and SBGT.	0	CSCS will start only if their individual system initiation signals are also present.
First RHR pump at speed. Start second RHR pump.	5	
Core Spray pumps signaled to start.	10	
Standby Service Water pump starts.	13	
Standby REC pump starts.	20	

NOTE: After sequential loading has taken place, additional equipment is started and secured as needed and as permitted by DG capacity.

ECCS loads will undergo sequential loading upon receipt of an auto initiation signal regardless of the source of power supplying the emergency buses. All non-ECCS loads that are part of sequential loading will only do so following a load shed and subsequent energization of the associated critical bus from an emergency source. If power to the emergency buses is lost, then regained from a non-emergency source, the service water pumps in "AUTO" will start immediately on low pressure and the "standby" pumps will not auto-start at all, while all REC pumps will remain off if the re-energization from the non-emergency source occurs after greater than 0.5 seconds have elapsed since the power loss.

* The seconds listed represent the time from diesel generator output circuit breaker closure

Examination Outline Cross-Reference	Level	RO
263000 (SF6 DC) DC Electrical Distribution Ability to manually operate and/or monitor in the control room: A4.01 Major breakers and control power fuses: Plant-Specific	Tier#	2
	Group#	1
	K/A #	263000 A4.01
	Rating	3.3
	Revision	0
Revision Statement:		

Question 23

The plant is at 50% power.

The following alarm is received:

250V DC SWGR BUS 1A BLOWN FUSE	PANEL/WINDOW: C-1/A-1

One hour later, 250 VDC Bus 1A voltage has lowered from 265 VDC to 249 VDC.

(1) Which one of the following caused these indications?

AND

(2) What is the status of the associated red fuse status light on the front of 250 VDC Switchgear 1A?

A. (1) 250 VDC BATTERY 1A BLOWN FUSE
(2) On

B. (1) 250 VDC BATTERY 1A BLOWN FUSE
(2) Off

C. (1) 250 VDC FEEDER FROM BATT CHARGER 1A BLOWN FUSE
(2) On

D. (1) 250 VDC FEEDER FROM BATT CHARGER 1A BLOWN FUSE
(2) Off

Answer: C
Explanation:

The 250 VDC system uses fused disconnects versus breakers for power distribution. Indication of fused disconnect status is provided by annunciators on Panel C. Operation of the fused disconnects are local, only.

250 VDC Battery Charger 1A supplies 250 VDC Bus 1A via a fused disconnect. 250 VDC Battery 1A is also connected to 250 VDC Bus 1A via a fused disconnect. 250 VDC Charger 1A maintains 250 VDC Bus 1A at ~ 265 VDC to supply the various DC loads and to maintain 250 VDC Battery 1A charged. 250 VDC Bus 1A supplies the following loads via fused disconnects:

- 250 VDC Rx Bldg Div 1 Starter Rack
- 250 VDC RCIC Starter Rack Normal Feeder
- 250 VDC Turbine Bldg Starter Rack Emerg Feeder
- 250 VDC Static Inverter 1A for NBPP

The following are inputs to annunciator C-1/A-2:

- 250 VDC BATTERY 1A BLOWN FUSE
- 250 VDC FEEDER FROM BATT CHARGER 1A BLOWN FUSE
- 250 VDC RX BLDG DIV 1 SR BLOWN FUSE
- 250 VDC RCIC SR NORMAL FEEDER BLOWN FUSE
- 250 VDC TURB SR EMERG FEEDER BLOWN FUSE
- 250 VDC STATIC INV 1A FEEDER BLOWN FUSE

Since the subject alarm was the only alarm received, only failure of the charger fuse or battery fuse could have caused the alarm with the absence of any other alarm. Since 250 VDC Bus 1A voltage is lowering, the charger must not be supplying the bus, since its output is higher than battery output alone and because it is a full capacity charger. Bus voltage is lowering because the battery is discharging as it alone supplies the bus.

The red fuse status light for the Battery Charger fused disconnect on the front of 250 VDC Switchgear 1A illuminates when the fuse blows.

Distracter:

Answer A part 1 is plausible because it represents an input to the subject alarm. It would be correct if 250 VDC bus voltage remained stable. It is wrong because with the charger not connected to the bus, 250 VDC Battery 1A is supplying the load, and its voltage lowers as the battery discharges. Part 2 is correct

Answer B part 1 is plausible and wrong for the reason given for distractor A. Part 2 is plausible because some status indicating lights, such as RPS bus power available lights on Panel 9-16, are illuminated when conditions are normal and power is available, and they extinguish when something has resulted in a loss of power. It is wrong because the red fuse status light for the Battery Charger fused disconnect on the front of 250 VDC Switchgear 1A illuminates when the fuse blows.

Answer D part 1 is correct. Part 2 is plausible and wrong for the reasons stated for distractor B.

Technical References: Alarm card C-1/A-1 [250V DC Swgr Bus 1A Blown Fuse](Rev 33), procedure (2) 2.2.24.1 [250 VDC Electrical System (Div 1)](Rev 17)		
References to be provided to applicants during exam: none		
Learning Objective: COR002-07-02 Obj LO-6c, Describe the interrelationship between the DC Electrical Distribution System and the following: Battery charger and battery; 8e, Given a specific DC Electrical Distribution system malfunction, determine the effect on any of the following: Batteries		
Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(7)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA Applicability:		
Top 10 Risk Significant System – Emergency DC Power		

SETPOINT	CIC	C-1/A-1
Blown fuse on SWGR for:		
1. (3700) 250 VDC BATTERY 1A BLOWN FUSE	1. EE-DSC-250A(BAT)	
2. (3701) 250 VDC RX BLDG DIV 1 SR BLOWN FUSE	2. EE-DSC-250A(DIV 1)	
3. (3702) 250 VDC FEEDER FROM BATT CHARGER 1A BLOWN FUSE	3. EE-DSC-250A(CHG)	
4. (3703) 250 VDC RCIC SR NORMAL FEEDER BLOWN FUSE	4. EE-DSC-250A(RCIC)	
5. (3704) 250 VDC TURB SR EMERG FEEDER BLOWN FUSE	5. EE-DSC-250A(TURB)	
6. (3705) 250 VDC STATIC INV 1A FEEDER BLOWN FUSE	6. EE-DSC-250A(INV-A)	

REFERENCES

- Technical Specification LCO 3.5.1, ECCS - Operating.
- Technical Specification LCO 3.5.2, Reactor Pressure Vessel (RPV) Water Inventory Control.
- Technical Specification LCO 3.5.3, RCIC System.
- Administrative Procedure 0.31, Equipment Status Control.
- System Operating Procedure 2.2.24.1, 250 VDC Electrical System (Div 1).
- Emergency Procedure 5.3NBPP, No Break Power Failure.

ATTACHMENT 3 INFORMATION SHEET

ATTACHMENT 3 INFORMATION SHEET

1. DISCUSSION

1.1 FUNCTION

1.1.1 The system provides an uninterruptible source of power to 250 VDC loads under normal and emergency operating conditions.

1.2 OPERATING CHARACTERISTICS

1.2.1 The 250 VDC System supplies DC power to conventional station emergency equipment and selected Safeguard System loads. The battery chargers receive their power from 460V critical motor control centers. Each 250 VDC bus receives power from either a 250 VDC battery or a 250 VDC battery charger.

1.2.2 Annunciator C-1/A-1, 250 VDC SWGR BUS 1A BLOWN FUSE, alarms when a fuse(s) for a breaker on 250 VDC Switchgear 1A or 1B blows. The fuse(s) and "Blown Fuse Indicator Switch(es)" must be replaced to clear alarm. Red "Fuse Status" light(s) on the front of 250 VDC Switchgear 1A will turn on when a fuse(s) blows.

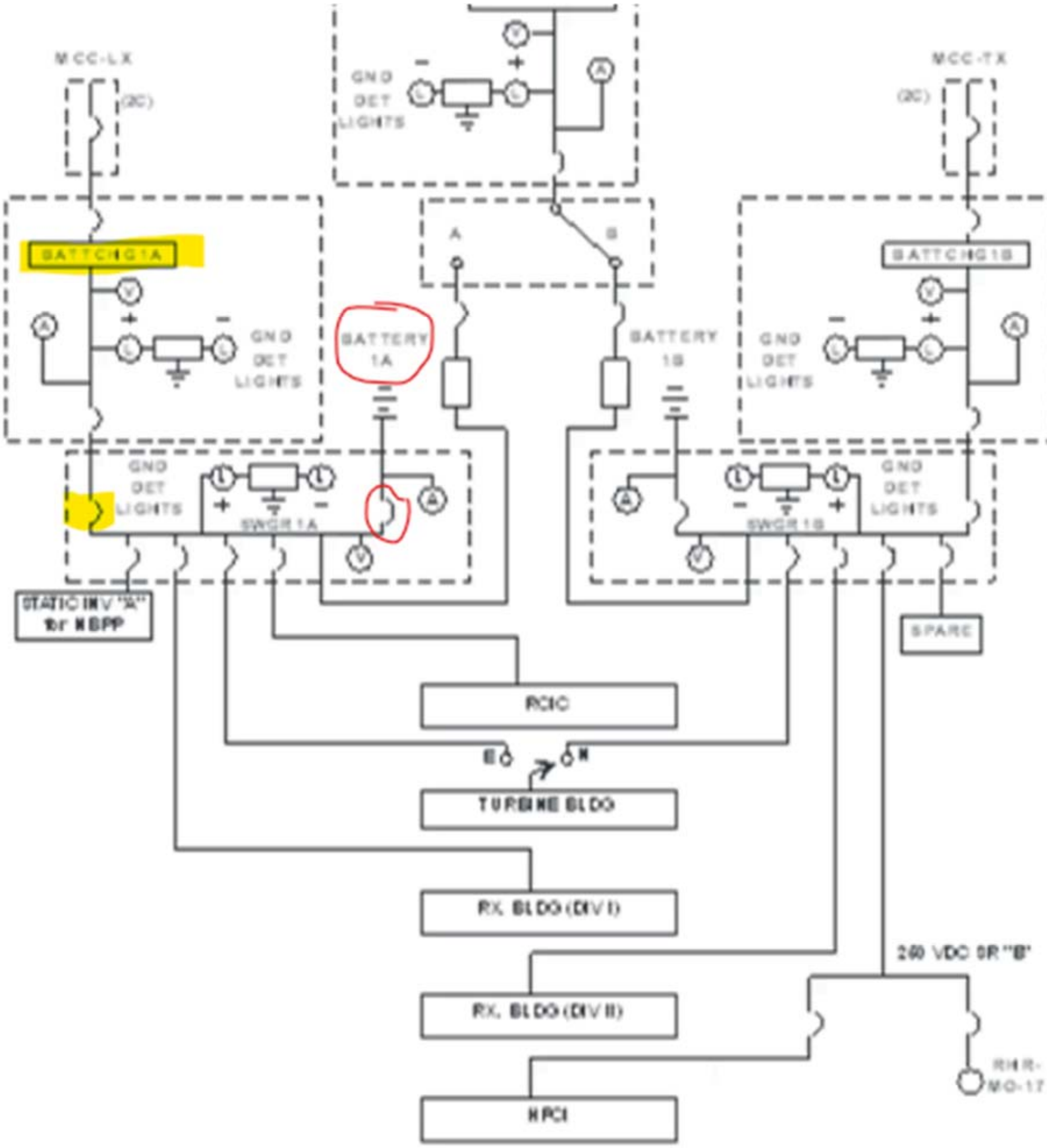
1.2.3 In a normal system line-up, 250V Charger 1A powers 250 VDC Bus 1A. A third battery charger, 250V Charger 1C, can also power 250 VDC Bus 1A. When 250V Charger 1C not in service, Annunciator C-1/D-1, 250 VDC BATT CHARGER 1C TROUBLE, can be cleared by placing 250V CHARGER ALARM BYPASS switch in BYPASS (CLOSED) position.

1.2.4 The RCIC Starter Rack is fed from 250 VDC Bus 1A and powers RCIC condensate pump and RCIC vacuum pump.

1.2.5 The 250 VDC Turbine Building Starter Rack, is fed from 250 VDC Bus 1A or 1B through a manual transfer switch and powers main turbine emergency oil pump, air side seal backup pump, and reactor feed pump turbine emergency oil pumps.

1.2.6 The 250 VDC Division 1 Reactor Building Starter Rack is fed from 250 VDC Bus 1A and powers RHR-MO-25A and RR-MO-53A.

1.2.7 250 VDC breakers are Model DB-50 and Model DB-25. Except for size, breakers are substantially the same, except that DB-25s use two (2) rail release latches (one on each side) and the DB-50s use only one (on the right side rail).



250 VDC POWER SYSTEM
FIGURE 1, Rev. 7

Examination Outline Cross-Reference	Level	RO
215005 (SF7 PRMS) Average Power Range Monitor/Local Power Range Monitor Knowledge of AVERAGE POWER RANGE MONITOR/LOCAL POWER RANGE MONITOR SYSTEM design feature(s) and/or interlocks which provide for the following: K4.07 Flow biased trip setpoints	Tier#	2
	Group#	1
	K/A #	215005 K4.07
	Rating	3.7
	Revision	0
Revision Statement:		

Question 24

The plant is at 100% power.

What is the nominal APRM neutron flux high (flow biased) trip setpoint for RPS?

A. ≤ 0.75W + 62% -0.75 ΔW RTP

B. ≤ 0.62W + 75% -0.62 ΔW RTP

C. ≤ 0.75W + 51% -0.75 ΔW RTP

D. ≤ 0.62W + 51% -0.62 ΔW RTP

Answer: A

Explanation:
At 100% power, two Reactor Recirc loops are in operation. The APRM neutron flux high (flow biased) trip setpoint for RPS during two Recirc loop operation is ≤ 0.75W + 62% -0.75 ΔW RTP. TS Table 3.3.1.1-1 [RPS Instrumentation] lists it as ≤ 0.75W + 62% RTP, since ΔW in 2-loop operation is zero.

Distracters:
Answer B is plausible because it contains the same numbers as the correct answer, just rearranged. It is wrong because the APRM neutron flux high (flow biased) trip setpoint for RPS listed in TS Table 3.3.1.1-1 [RPS Instrumentation] is ≤ 0.75W + 62% RTP.

Answer C is plausible because it reflects the APRM flow biased upscale control rod withdrawal block setpoint from TRM Table T3.3.1-1 [Control Rod Block Instrumentation]. It is wrong for the same reason stated for distractor B.

Answer D is plausible because it contains a combination of numbers from the APRM flow biased RPS and Control Rod Block equations. It is wrong for the same reason given for distractor B.		
Technical References: TS Table 3.3.1.1-1 [RPS Instrumentation], TRM Table T3.3.1-1 [Control Rod Block Instrumentation], Procedure 4.1.3 [Average Power Range Monitoring System](Rev 26)		
References to be provided to applicants during exam: none		
Learning Objective: COR002-01-02 Obj LO-8e, Describe the APRM design feature(s) and/or interlock(s) that provide for the following: Flow biased trip setpoints		
Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(6)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA Applicability:		
Top 10 Risk Significant System - RPS		

2.1.3 When not in RUN Mode, the downscale rod blocks (≥ 3.0%) are bypassed.

2.2 SETPOINTS - LPRM

Trip Function	Setpoint	Action
LPRM downscale	3 W/cm^2	Light and annunciator
LPRM upscale	100 W/cm^2	Light and annunciator
LPRM bypass	N/A	Light and APRM averaging compensation

NOTE – Any one APRM can initiate a rod block and half scram. One APRM rod block and half scram input can be bypassed in each trip circuit.

2.3 SETPOINTS - APRM

Trip Function	Tech Spec/TRM Limit	Action
APRM downscale	≥ 3.0%	Rod block, annunciator, white light IRM scram interlock
APRM upscale (High) flow bias	≤ 0.75W + 51.0% - .75ΔW	Rod block, annunciator, amber light
APRM upscale (High) fixed	≤ 109.5% RTP	Rod block, annunciator, amber light
APRM upscale (High-High) flow bias	≤ 0.75W + 62.0% - .75ΔW	Scram, annunciator, red light
APRM upscale (High-High) fixed	≤ 120% RTP	Scram, annunciator, red light
APRM inoperative	APRM MODE switch not in OPERATE or < 11 LPRM inputs or module unplugged	Rod block, scram, annunciator, red light

3. REFERENCES

3.1 TECHNICAL SPECIFICATIONS

3.1.1 LCO 3.3.1.1, Reactor Protection System (RPS) Instrumentation.

3.1.2 Section 2.0, Safety Limits (SLs).

RPS Instrumentation
3.3.1.1

Table 3.3.1.1-1 (page 1 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Intermediate Range Monitors					
a. Neutron Flux — High	2	3	G	SR 3.3.1.1.1 SR 3.3.1.1.3 SR 3.3.1.1.4 SR 3.3.1.1.5 SR 3.3.1.1.6 SR 3.3.1.1.12[a,b] SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 121/125 divisions of full scale
	5[c]	3	H	SR 3.3.1.1.1 SR 3.3.1.1.3 SR 3.3.1.1.4 SR 3.3.1.1.12[a,b] SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 121/125 divisions of full scale
b. Inop	2	3	G	SR 3.3.1.1.3 SR 3.3.1.1.4 SR 3.3.1.1.13	NA
	5[c]	3	H	SR 3.3.1.1.3 SR 3.3.1.1.4 SR 3.3.1.1.13	NA
2. Average Power Range Monitors					
a. Neutron Flux — High (Startup)	2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.3 SR 3.3.1.1.4 SR 3.3.1.1.6 SR 3.3.1.1.8 SR 3.3.1.1.10[a,b] SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 14.5% RTP
b. Neutron Flux-High (Flow Biased)	1	2	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.4 SR 3.3.1.1.7 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.10[a,b] SR 3.3.1.1.12[a,b] SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 0.75 W + 62.0% RTP[d]

(continued)

(a) If the as-found channel setpoint is outside its predefined as-found tolerance, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

(b) The instrument channel setpoint shall be reset to a value that is within the as-left tolerance around the Limiting Trip Setpoint (LTSP) at the completion of the surveillance; otherwise, the channel shall be declared inoperable. Setpoints more conservative than the LTSP are acceptable provided that the as-found and as-left tolerances apply to the actual setpoint implemented in the Surveillance procedures (Nominal Trip Setpoint) to confirm channel performance. The Limiting Trip Setpoint and the methodologies used to determine the as-found and the as-left tolerances are specified in the Technical Requirements Manual.

(c) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

(d) [0.75 W + 62.0% - 0.75 ΔW] RTP when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating."

Control Rod Block Instrumentation
T 3.3.1

Table T3.3.1-1 (Page 2 of 3)
Control Rod Block Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	ACCEPTANCE LIMITS
2. IRM				
a. Detector Not Full In	2	6	TSR 3.3.1.1 TSR 3.3.1.3 TSR 3.3.1.8	NA
b. Upscale	2	6	TSR 3.3.1.1 TSR 3.3.1.3 TSR 3.3.1.4 TSR 3.3.1.8	≤ 108/125 of Full Scale
c. Inoperative	2	6	TSR 3.3.1.3 TSR 3.3.1.4	NA
d. Downscale	2(d)	6	TSR 3.3.1.1 TSR 3.3.1.3 TSR 3.3.1.4 TSR 3.3.1.8	≥ 2.5/125 of Full Scale
3. APRM				
a. Upscale (Flow Biased)	1	4	TSR 3.3.1.1 TSR 3.3.1.2 TSR 3.3.1.5 TSR 3.3.1.7(e)	≤ (0.75W + 51.0% - 0.75 ΔW) (f)(g)
b. Upscale (Startup)	2	4	TSR 3.3.1.1 TSR 3.3.1.4 TSR 3.3.1.7	≤ 11.5%
c. Inoperative	1, 2	4	TSR 3.3.1.1 TSR 3.3.1.5	NA
d. Downscale	1	4	TSR 3.3.1.1 TSR 3.3.1.5 TSR 3.3.1.7	≥ 3%
e. Upscale (Fixed)	1	4	TSR 3.3.1.1 TSR 3.3.1.2 TSR 3.3.1.5 TSR 3.3.1.7	≤ 109.5%

(continued)

(d) With IRMs on Range 2 or above.

(e) Calibration of the recirculation loop flow transmitters is only required once every 24 months.

(f) W is the two-loop recirculation flow rate in percent of rated. Trip level setting is in percent of rated power (2419 = 100% RTP).

(g) ΔW is the difference between two-loop and single-loop effective drive flow and is used for single recirculation loop operation. ΔW = 0 for two loop recirculation loop operation.

Examination Outline Cross-Reference	Level	RO
209001 (SF2, SF4 LPCS) Low-Pressure Core Spray Knowledge of the operational implications of the following concepts as they apply to LOW PRESSURE CORE SPRAY SYSTEM: K5.04 Heat removal (transfer) mechanisms	Tier#	2
	Group#	1
	K/A #	209001 K5.04
	Rating	2.8
	Revision	
Revision Statement:		

Question 25

Regarding decay heat removal by Core Spray,

(1) What is the predominant heat removal mechanism produced by Core Spray for **uncovered portions** of the reactor fuel?

AND

(2) Which one of the following is the LOWEST reactor water level at which Core Spray at rated flow provides **adequate core cooling**?

A. (1) Conductive heat transfer
(2) -195 inches

B. (1) Conductive heat transfer
(2) -209 inches

C. (1) Convective heat transfer
(2) -195 inches

D. (1) Convective heat transfer
(2) -209 inches

Answer: D
Explanation: Core Spray injects through four spargers located inside the core shroud above the core. CS A injects via the two lower spargers, and CS B injects via the two upper spargers. CS can provide either conductive or convective heat transfer to assure adequate core cooling. When the Core Spray system is used to provide core submergence, cooling is by conductive heat transfer. Core submergence exists when level is at or above TAF, -158 inches. The heat transfer mechanism transitions from conduction to convection when level falls below TAF. A Core Spray subsystem provides the required conductive heat transfer when flow rate is at least 4750 gpm at the established spray pattern. Core Spray produces a low pressure area above the core that promotes convective cooling by increasing steam flow up through the core.

Convective cooling absorbs the sensible heat from the surrounding atmosphere. Core Spray can provide sufficient spray flow to assure adequate core cooling until reactor water level falls below -209 inches, the elevation of the jet pump suction.

Distracters:
Answer A part 1 is plausible because CS provides core cooling predominantly by conduction when level is above TAF. It is wrong because for uncovered portions of the fuel, the predominant heat transfer mechanism is convective heat transfer by steam flow. Part 2 is plausible because -195" is the Minimum Zero Injection RPV Water Level (MZIRWL). As long as there is no injection from any system, when level falls below -183" (MSCRWL), there is sufficient steam flow produced by the core to assure adequate core cooling through convective heat transfer until level falls below -195". The examinee who confuses this limit with the limit for spray cooling will choose this answer. It is wrong because CS at rated flow ensures adequate core cooling as long as level is not below the elevation of the jet pump inlet nozzles, -209".

Answer B part 1 is plausible and wrong for the same reason stated for distractor A. Part 2 is correct.

Answer C part 1 is correct. Part 2 is plausible and wrong for the same reason stated for distractor A.

Technical References: Lesson Plan COR002-06-02 [Ops Core Spray System], AMP-TBD00 [PSTGs](Rev 10), EOP-1A [RPV Control](Rev 22)

References to be provided to applicants during exam: none

Learning Objective: COR002-06-02 Obj LO-6c, Briefly describe the following concepts as they apply to the Core Spray system: Heat removal (transfer) mechanisms

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X

Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X

10CFR Part 55 Content:	55.41(b)(7)
Level of Difficulty:	3
SRO Only Justification:	N/A
PSA Applicability:	

N/A

Lesson Number:	COR002-06-02	Revision: 27

LO-04c c. Diesel Generators

The CS initiation logic also gives a start signal to the Diesel Generators on high drywell pressure and low-low-low reactor water level. This logic must energize to make this happen, and a failure of this logic could prevent Diesel Generator auto start functions.

LO-04d d. Reactor Vessel Internals

The Core Spray system pumps Suppression Pool water into spray headers located inside the core shroud. Should the Core Spray system fail, the reactor vessel internals could be subjected to extremely high temperatures causing a metal-water reaction to threaten vessel internals integrity.

2. Concepts Associated with the Core Spray system

LO-06a a. Indications of Pump Cavitation

Each Core Spray loop has pressure and flow indicators in the Control Room. When a Core Spray pump begins to cavitate, these indicators will begin to oscillate depending on the severity of the cavitation. The inboard injection valves can be throttled in the closed direction until the flow and pressure instruments indicate a more stable indication, or the pumps can be secured.

LO-06c b. Heat Removal (transfer) Mechanisms

When the Core Spray system is utilizing the spray headers inside the core shroud for cooling, convective cooling absorbs the sensible heat from the surrounding atmosphere. When the Core Spray system is used to provide core submergence, the cooling mechanism used is conductive cooling.

LO-06d c. System Venting

The Core Spray system is filled with water and vented when aligned for standby status following an outage or maintenance. When the system is operated for surveillance testing, it is again vented to assure the system is filled with water. The venting removes air in the system that may have accumulated, and this prevents water hammer effects from possibly causing damage to system components if the system was put into operation.

3. Effects of a loss or malfunction of the following on the Core Spray system.

LO-07c
LO-09f a. Suppression Pool Water Level

PSTG / SATG AMP-TBD00
Tech. Basis – App. B

PSTG/SATG Step (RC/L-3.3, continued)

If either:

- RPV water level cannot be restored and maintained above -183 in. (Minimum Steam Cooling RPV Water Level) and no core spray subsystem flow can be restored and maintained equal to or greater than 4,721 gpm (design core spray flow), or
- RPV water level cannot be restored and maintained at or above -209 in. (elevation of jet pump suction),

then:

(a) Maximize injection into the RPV using available Preferred Injection Systems (Table L-1), Injection Subsystems, and Alternate Injection Subsystems (Table L-2).

(b) If RPV water level cannot be restored and maintained above -183 in. (Minimum Steam Cooling RPV Water Level), exit all procedures developed from the PSTGs and enter all guidelines developed from the SATGs.

PSTG / SATG AMP-TBD00
Tech. Basis – App. B

3. DEFINITIONS/USAGE OF KEY WORDS/PHRASES

The meaning of the following terms is discussed in the context of their use within the PSTGs/SATGs. This information is provided to facilitate a consistent and technically accurate understanding of the guidelines.

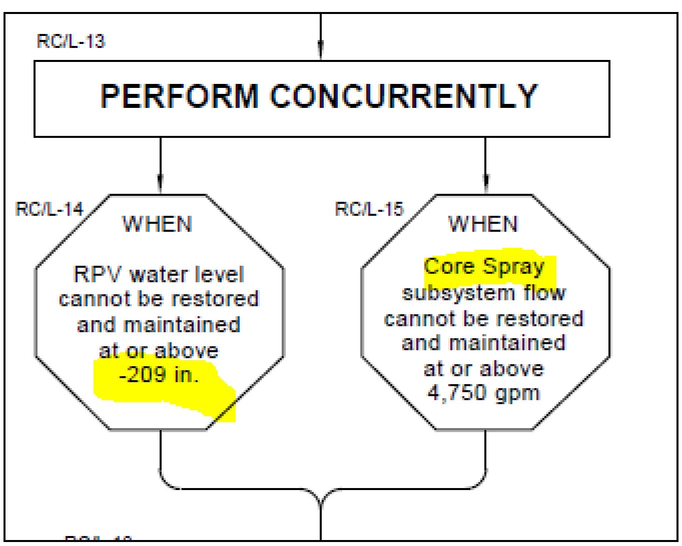
Adequate core cooling: Heat removal from the reactor sufficient to prevent rupturing the fuel clad. Within the PSTGs, three viable mechanisms for establishing adequate core cooling are defined—core submergence, spray cooling, and steam cooling.

Submergence is the preferred method for cooling the core. The core is adequately cooled by submergence when it can be determined that RPV water level is at or above the top of the fuel. All fuel nodes are then assumed to be covered with water and heat is removed by boiling heat transfer.

Adequate spray cooling is provided, assuming a bounding axial power shape, when design spray flow requirements are satisfied and RPV water level is at or above the elevation of the jet pump suctions. The covered portion of the core is then cooled by submergence while the uncovered portion is cooled by the spray flow.

Steam cooling is relied upon only if RPV water level cannot be restored and maintained above the top of the fuel, cannot be determined, or must be intentionally lowered below the top of fuel. The core is adequately cooled by steam if the steam flow across the uncovered length of each fuel bundle is sufficient to maintain the hottest peak clad temperature below the appropriate limiting value—1500°F if makeup can be injected, 1800°F if makeup cannot be injected. The covered portion of the core remains cooled by boiling heat transfer and generates the steam which cools the uncovered portion.

From EOP-1A



18.21 Minimum Steam Cooling RPV Water Level

The Minimum Steam Cooling RPV Water Level (MSCRWL) is the lowest RPV water level at which the covered portion of the reactor core will generate sufficient steam to prevent any clad temperature in the uncovered part of the core from exceeding 1500°F.

The derivation of the MSCRWL is shown graphically in Figure B-18-16. Curve A graphs the steam flow required to maintain clad temperature less than 1500°F. Curve B graphs the actual steam flow generated by the reactor core. At the intersection of Curves A and B, the steam flow generated by the partially submerged core equals the steam flow needed for cooling the uncovered part of the core. The corresponding level is the MSCRWL.

The MSCRWL is determined assuming:

1. The reactor has been shutdown from rated power for ten minutes.
2. The reactor axial power shape was the most limiting top-peaked power shape prior to reactor shutdown.
3. The temperature of the water injected into the RPV is 100°F.

CNS input data required to calculate the MSCRWL are:

1. Minimum fuel length fraction which must be covered to maintain peak clad temperature below 1500°F with injection.
2. Fuel length.
3. Water level at the bottom of fuel.

The MSCRWL differs from the Minimum Zero-Injection RPV Water Level (MZIRWL) in two respects:

1. The MSCRWL is based upon maintaining peak clad temperature below 1500°F. The MZIRWL is based upon maintaining peak clad temperature below 1800°F.
2. Water in the lower plenum is assumed to be subcooled in the MSCRWL calculation. It is assumed to be saturated in the MZIRWL calculation.

The MSCRWL is referenced in the following PSTG steps:

- C1-4

(2) Stabilize RPV pressure using one or more RPV Depressurization Systems (Table P-2), defeating isolations and interlocks and exceeding offsite radioactivity release rate limits if necessary.

(3) When RPV water level drops to -195 in. (Minimum Zero-Injection RPV Water Level), continue at Substep (4).

18.22 Minimum Zero-Injection RPV Water Level

The Minimum Zero-Injection RPV Water Level (MZIRWL) is the lowest RPV water level at which the covered portion of the reactor core will generate sufficient steam to prevent any clad temperature in the uncovered part of the core from exceeding 1800°F.

The derivation of the MZIRWL is shown graphically in Figure B-18-17. Curve A graphs the steam flow required to maintain clad temperature less than 1800°F. Curve B graphs the actual steam flow generated by the reactor core. At the intersection of Curves A and B, the steam flow generated by the partially submerged core equals the steam flow needed for cooling the uncovered part of the core. The corresponding level is the MZIRWL.

The MZIRWL is determined assuming:

1. The reactor has been shutdown from rated power for ten minutes.
2. The reactor axial power shape was the most limiting top-peaked power shape prior to reactor shutdown.
3. No water is injected into the RPV.

CNS input data required to calculate the MZIRWL are:

1. Minimum fuel length fraction which must be covered to maintain peak clad temperature below 1800°F without injection.
2. Fuel length.
3. Water level at the bottom of fuel.

The MZIRWL differs from the Minimum Steam Cooling RPV Water Level (MSCRWL) in two respects:

1. The MZIRWL is based upon maintaining peak clad temperature below 1800°F. The MSCRWL is based upon maintaining peak clad temperature below 1500°F.
2. Water in the lower plenum is assumed to be saturated in the MZIRWL calculation. It is assumed to be subcooled in the MSCRWL calculation.

The MZIRWL is referenced in PSTG Step C1/P-3(3).

Examination Outline Cross-Reference	Level	RO
203000 (SF2, SF4 RHR/LPCI) RHR/LPCI: Injection Mode Ability to predict and/or monitor changes in parameters associated with operating the RHR/LPCI: INJECTION MODE (PLANT SPECIFIC) controls including: A1.01 Reactor water level	Tier#	2
	Group#	1
	K/A #	203000 A1.01
	Rating	4.2
	Revision	0
Revision Statement:		

Question 26

A LOCA is in progress following a scram with the following conditions:

- EOP PTMs 97 through 100 are **installed**
- RHR Pump A is operating on minimum flow after being secured from Drywell Spray
- RHR-MO-27A [Outboard Injection Valve] is CLOSED
- Reactor pressure is 500 psig, slowly lowering
- Reactor water level is at -113 inches, lowering 0.5 inch/minute

(1) Which one of the following describes operation of RHR-MO-27A under these conditions in order to raise reactor water level as reactor pressure continues to lower?

AND

(2) According to Operations Instruction #8 [Guideline for Successful Transient Mitigation], which level instrumentation is required to be used to monitor and control reactor water level under these conditions?

A. (1) RHR-MO-27A control switch must be held in OPEN to open fully
(2) Fuel Zone

B. (1) RHR-MO-27A control switch must be held in OPEN to open fully
(2) Wide Range

C. (1) RHR-MO-27A will open automatically
(2) Fuel Zone

D. (1) RHR-MO-27A will open automatically
(2) Wide Range

Answer: A

Explanation:
Conditions in the stem reflect a LPCI initiation signal is present and RHR-MO-27A is closed. RHR-MO-27A is normally open and is designed to automatically and fully open when an ECCS ignition signal is present (low reactor water level ≤-113" (Level 1) or high DW pressure ≥1.84 psig) and reactor pressure lowers below the injection RPV pressure permissive (436 psig). EOP Plant Temporary Modifications (PTMs) 97-100 are installed, normally performed for containment spray operation. These jumpers defeat the automatic open signal to RHR-MO-27A and 27B and cause the valves to behave as throttle valves. Therefore, the control switch for RHR-MO-27A must be held in OPEN to cause the valve to fully open.

Operations Instruction #8 provides directions for which level bands and which level instrumentation ranges to use for various transient condition. In non-ATWS conditions, such as this case, OI#8 directs use of Fuel Zone for monitoring and controlling reactor water level.

Distracters:
Answer B part 1 is correct. Part 2 is plausible because Level 1 (-113") is above -130", and OI#8 directs using Wide Range level instrumentation until level drops below -130" during ATWS conditions. It is wrong because ATWS conditions do not exist, so Fuel Zone is required to be used.

Answer C part 1 is plausible because Reactor water level is at Level 1, so LPCI initiation signal is present, and RHR-MO-27A is designed to automatically open when RPV pressure falls below 436 psig. It is wrong because EOP PTMs 97-100 are installed, which defeat the automatic open signal to RHR-MO-27A. Part 2 is correct.

Answer D part 1 is plausible and wrong for the reason given for distractor C. Part 2 is plausible and wrong for the reason given for distractor B.

Technical References: Procedure 5.8.20 [EOP Plant Temporary Modifications](Rev 21), Operations Instruction #8 [Guideline for Successful Transient Mitigation](Rev 19), Lesson Plan COR002-23-02 [Ops Residual Heat Removal System](Rev 36)

References to be provided to applicants during exam: none

Learning Objective: INT008-05-01 EO-1, Given a simulator scenario, determine which support procedures and Plant Temporary Modifications (PTMs) should be used based on plant conditions and EOP strategy being utilized; EO-5 State the reasons why all PTM's are installed versus select PTM's for priority equipment such as HPCI and RCIC.

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X

Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(7),(10)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA Applicability:		
Top 10 Risk Significant System - RHR		

LO-05b SO-02e LO-03b,g ,04n, 15d,e	c. Outboard injection valve MO-27A(B) 1) Normally open valve, opens with the control switch on Panel 9-3 (27B *) positioned to OPEN (spring return to AUTO) and one of the following permissives: a) MO-25A(B) closed, OR b) Reactor pressure ≤ 436 psig.
LO-03a, 04n	2) Opens if closed and a LPCI initiation signal is received and reactor pressure is ≤ 436 psig. It is interlocked open for 5 minutes to ensure full flow to the vessel. The 5 minute timer does not start until reactor pressure is reduced to ≤436 psig.
LO-03o, 06d,f	3) Can be throttled with control switch on Panel 9-3 unless interlocked open. This allows the Control Room operator to control system flow and reactor water level.
LO-14a,b	4) The interlocks for MO-27B are removed when its ASD switch is in isolate.

Page 21 of 35

Lesson Number: COR002-23-02	Revision: 36

10. BYPASSING RHR OUTBD INJECTION VLV AUTOMATIC OPEN

CAUTION – This section may require dispatching personnel through or into potentially high radiation areas.

10.1 Refer to Section 3 when dispatching personnel to perform actions outside Control Room.

NOTE – EOP PTMs are dependent upon plant conditions and are not required to be implemented in all situations.

10.2 To defeat automatic open interlocks for RHR-MO-27A, OUTBD INJECTION VLV, perform following; N/A if not required by plant conditions:

10.2.1 Install EOP PTM # 97, lift Wire RH197-13 from GG-84 BAY-2, PNL 9-32 (C-903-AUX RELAY RM).

Completed By: ________

10.2.2 Install EOP PTM # 98, jumper between Terminals GG-85 and GG-86 BAY-2, PNL 9-32 (C-903-AUX RELAY RM).

Completed By: ________

10.3 To defeat automatic open interlocks for RHR-MO-27B, OUTBD INJECTION VLV, perform following; N/A if not required by plant conditions:

10.3.1 Install EOP PTM # 99, lift Wire RH22-13 from GG-84 BAY-2, PNL 9-33 (C-903-AUX RELAY RM).

Completed By: ________

10.3.2 Install EOP PTM # 100, jumper between Terminals GG-85 and GG-86 BAY-2, PNL 9-33 (C-903-AUX RELAY RM).

Completed By: ________

10.4 Inform CRS RHR OUTBD INJECTION VLV AUTOMATIC OPEN interlocks are bypassed for EOPs.

10.5 WHEN directed by CRS, THEN restore RHR OUTBD INJECTION VLV AUTOMATIC OPEN interlocks by removing following EOP PTMs, if installed; N/A if PTMs not installed:

10.5.1 (Independent Verification) Remove EOP PTM # 97# by landing Wire RH197-13 to Terminal GG-84, PNL 9-32, BAY-2 (C-903-AUX RELAY RM).

Performed By: ________

Verified By: ________

B. Post-Scram RPV Water Level Reporting

The monitoring and reporting of RPV water level is of the highest priority during post-scram transient conditions and must be performed with precision at all times. The following guidance will be used to ensure consistent use of diverse RPV level indicators during both ATWS and non-ATWS conditions. The reporting of key RPV operational criteria *(-42", -113", -158", -183")* is still required during these strategies.

1. Non-ATWS conditions:

- During transients in which it is desired and possible to maintain RPV water level within 3" to 54" Narrow Range (NR), the NR instruments will be used for monitoring and control.

- When reactor level has lowered below -42" and cannot be restored and maintained above that level based on existing plant conditions. The crew should transition to reporting and controlling reactor level **using the fuel zone level instruments**.

2. ATWS Conditions:

OPERATIONS INSTRUCTION #8	REVISION 19	PAGE 8 OF 24

Operations Instruction #8 GUIDELINE FOR SUCCESSFUL TRANSIENT MITIGATION	Class: Information Use Effective: 03/08/19

- The Wide Range (WR) level instruments will initially be used for control and reporting until level drops below -130" WR.

Examination Outline Cross-Reference	Level	RO
288000 (SF9 PVS) Plant Ventilation Knowledge of the effect that a loss or malfunction of the PLANT VENTILATION SYSTEMS will have on following: K3.01 Secondary containment temperature: Plant-Specific	Tier#	2
	Group#	2
	K/A #	288000 K3.01
	Rating	2.8
	Revision	0
Revision Statement:		

Question 27

Reactor water level is -120” (Wide Range) during a LOCA.

MCC-K loses power.

Which one of the following secondary containment areas will experience a temperature rise FIRST due to loss of HVAC stemming from this power failure?

A. MSL Tunnel

B. RCIC Pump area

C. HPCI Pump area

D. Core Spray B Pump area

Answer: B
Explanation: MCC-K supplies power to NE Quad Core Spray A Room FCU. The FCU auto starts when CS Pump A breaker closes or when RCIC steam admission valve MO-131 opens. RCIC turbine/pump is located in the same room as CS Pump A. Both RCIC and CS Pump A have an initiation signal with WR level at -120”, adding heat to that area. Therefore, RCIC Pump area temperature will rise first as a result of loss of the NE Quad FCU.
Distracters: Answer A is plausible because Steam Tunnel FCUs are supplied by MCCs and the steam tunnel has a high heat load. It is wrong because Steam Tunnel FCUs are supplied by MCC-N and MCC-V.

Answer C is plausible because the HPCI room FCU is supplied by a MCC and HPCI would be running with reactor water level -120”, adding a high heat load to the area. It is wrong because HPCI room FCU is supplied by MCC-S. Answer D is plausible because the SE Quad CS-B Room FCU is supplied by a MCC and CS Pump B would be running with reactor water level -120”, adding a high heat load to the area. It is wrong because SE Quad CS-B Room FCU is supplied by MCC-S.
Technical References: Lesson plan COR001-08-01 [OPS Heating, Ventilation and Air Conditioning](Rev 30)
References to be provided to applicants during exam: none
Learning Objective: COR001-08-01 Obj LO- 9b, Given a specific HVAC malfunction, determine the effect on any of the following: Reactor Building temperature

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(8)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA Applicability:		
Top 10 Risk Significant System – Emergency AC Power		

Lesson Number:	COR001-08-01	Revision:	29

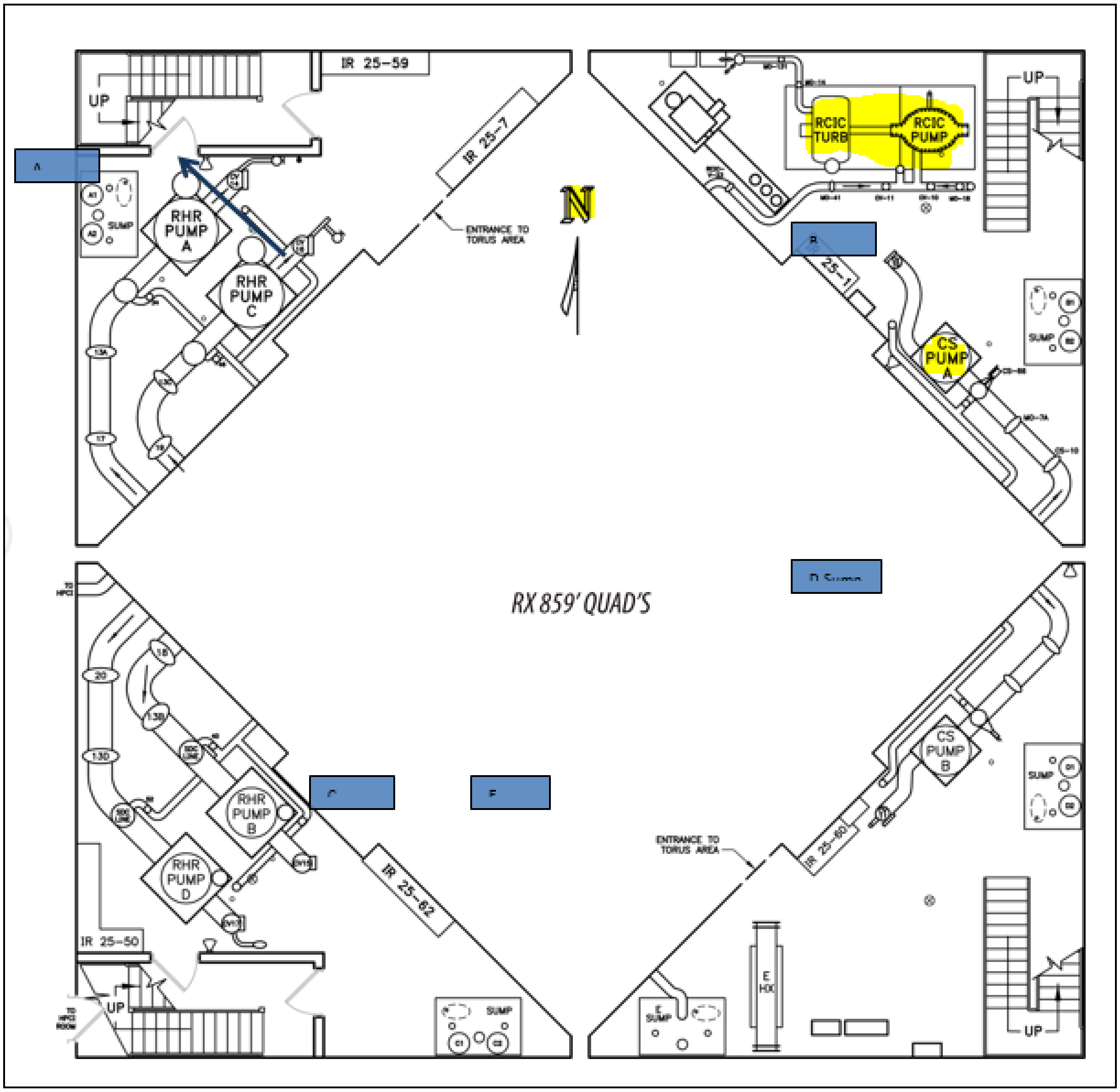
TABLE 3

SO-03a,b HVAC POWER SUPPLIES
LO-08a,b,c,d,e

COMPONENT TITLE	COMPONENT	POWER SUPPLY
RX BLDG SUPPLY FAN A	SF-R-1A-A	MCC-M
RX BLDG SUPPLY FAN B	SF-R-1A-B	MCC-U
RX BLDG EXH FAN A	EF-R-1A	MCC-M
RX BLDG EXH FAN B	EF-R-1B	MCC-U
RX BLDG HVAC EXH BOOSTER FAN A	BF-R-1A	MCC-N
RX BLDG HVAC EXH BOOSTER FAN B	BF-R-1B	MCC-V
SE QUAD CS-B ROOM FAN COIL UNIT	FC-R-1E	MCC-S
NE QUAD CS-A ROOM FAN COIL UNIT	FC-R-1F	MCC-K
HPCI ROOM FAN COIL UNIT	FC-R-1G	MCC-S
SW QUAD-RHR ROOM FAN COIL UNIT	FC-R-1H	MCC-S
NW QUAD-RHR RM FAN COIL UNIT	FC-R-1J	MCC-K
RRMG SET EXH FAN C	EF-R-1C	MCC-M
RRMG SET EXH FAN D	EF-R-1D	MCC-U
STEAM TUNNEL FAN COIL UNIT A	FC-R-1KA	MCC-N
STEAM TUNNEL FAN COIL UNIT B	FC-R-1KB	MCC-V

Lesson Number:	COR001-08-01	Revision:	30

Item/Location	Switch Positions	Functions
d. Reactor Building Supply Fans SF-R-1A-A(B); Panel R	OFF-STDBY-AUTO-RUN	AUTO-Runs if building ΔP in spec (-0.15" to -0.45" WG).
e. Reactor Building Filter Room Exhaust Booster Fans BF-R-1A(1B); Panel R	OFF-STDBY-AUTO-RUN	AUTO-Runs if exhaust fan running and ΔP in spec. (-0.15" to -0.45" WG).
f. Reactor Building Exhaust Fans EF-R-1A(1B); Panel R	OFF-STDBY-AUTO-RUN	AUTO-Runs if building ΔP in spec (-0.15" to -0.45" WG).
g. RRMG Set Exhaust Fans EF-R-1C(1D); Panel R	OFF-STDBY-AUTO	AUTO-Runs
h. Reactor Building 1) SE(NE) CS Room Fan Coil Units FC-R-1E(1F); Panel R 2) SW(NW)RHR Room Fan Coil Units FC-R-1H(1J); Panel R 3) HPCI Room Fan Coil Unit FC-R-1G; Panel R	OFF-AUTO-RUN OFF-AUTO-RUN OFF-AUTO-RUN OFF-ON	AUTO-FCU starts when associated CS pump motor breaker closes or if steam valves, MO-131, full open. AUTO-FCU starts if either one of the two associated RHR pump motor breakers close. AUTO-FCU starts if steam valve (MO-14) is open.


IR 25-59
UP
A
RHR PUMP A
RHR PUMP C
SUMP
IR 25-7
ENTRANCE TO TORUS AREA
N
RCIC TURB
RCIC PUMP
UP
B
25-1
CS PUMP A
SUMP
RX 859' QUAD'S
D Sump
RHR PUMP B
RHR PUMP D
C
E
IR 25-62
IR 25-50
UP
SUMP
CS PUMP B
SUMP
ENTRANCE TO TORUS AREA
IR 25-60
E HX
E SUMP
UP

Examination Outline Cross-Reference	Level	RO
295003 (APE 3) Partial or Complete Loss of AC Power / 6 Ability to determine and/or interpret the following as they apply to PARTIAL OR COMPLETE LOSS OF A.C. POWER: AA2.05 Whether a partial or complete loss of A.C. power has occurred	**Tier#**	1
	Group#	1
	K/A #	295003 AA2.05
	Rating	3.9
	Revision	0
Revision Statement:		

Question 28

A leak in the drywell occurred at 100% power.

Drywell pressure rises to 5 psig over 3 minutes AND **ALL systems function as designed**.

5 minutes later,

Drywell pressure has risen above 5.5 psig AND indication at RHR Pump A control switch is:

Which one of the following caused this indication for RHR Pump A?

A. Loss of DC power to RHR Pump A breaker

B. RPV pressure is above the LPCI injection permissive

C. Loss of AC power to the bus supplying RHR Pump A

D. RHR Pump A control switch has been placed in Pull-To-Lock

Answer: C

Explanation:
RHR Pump A is supplied by 4160 VAC Bus 1F. RHR pumps automatically start on high DW pressure, 1.84 psig. RHR pump control power, which powers control switch light indication, is supplied by 125 VDC and is unaffected by loss of AC power. Indication for a running RHR pump is Red light ON, Green light OFF, Amber light OFF. Loss of power to 4160 VAC Bus 1F causes RHR Pump A breaker to shed (trip open) on Low voltage on critical bus (2300V), resulting in Red light OFF, Green light ON, Amber light OFF. (The amber light illuminates only when the control switch is placed to STOP or PTL. It will then remain lit if there is an auto start signal present. It does not illuminate if the breaker opened due to load shedding.)

Distracters:
Answer A is plausible because loss of 125 VDC breaker control power would prevent RHR Pump A breaker from closing. It is wrong because 125 VDC control power supplies red and green lights at the breaker control switch, so the green light would be extinguished if control power had been lost. Also, the stem states ALL systems function as designed, so RHR Pump A would have already started when DW pressure exceeded 1.84 psig.

Answer B is plausible because not all RHR A components required for LPCI injection completely align for injection until RPV pressure falls below the injection permissive, 436 psig (e.g inboard injection valve RHR-MO-25A does not open until pressure is below the permissive). This answer is wrong because RHR A pump starts as soon as DW pressure rises to 1.84 psig.

Answer D is plausible because placing RHR Pump A control switch in PTL would cause the breaker to open, even with an initiation signal present. Placing RHR pumps in PTL is sometimes performed during LOCA conditions IAW Procedure 5.8 if systems are not needed for injection. It is wrong because placing the switch in PTL would also cause the amber light to illuminate, since the amber light illuminates when certain stop signals are present while an initiation signal is in.

Technical References: Lesson plan COR001-01-01 [Ops AC Electrical Distribution](Rev 50), Lesson plan COR002-23-02 [Residual Heat Removal System](Rev 36), procedure 2.2A_125DC.DIV1 [125 VDC POWER CHECKLIST (DIV 1)](Rev 7), procedure 5.8 [Emergency Operating Procedures(EOPs)](Rev 45)

References to be provided to applicants during exam: none

Learning Objective: COR001-01-01 Obj LO-8b, Predict the consequences of the following on plant operation: 4160V Critical Bus Undervoltage; COR002-23-02 Obj

LO-8a, Predict the consequences a malfunction of the following will have on the RHR system: A.C. electrical power (including RPS)		
Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(7)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA Applicability:		

Lesson Title: OPS AC Electrical Distribution	
Lesson Number: COR001-01-01	Revision Number: 50

b. The DG tie bus breakers (1FE and 1GE) shut, if open. (Note that the normal position for breakers 1FE and 1GE is shut).

c. Load Shedding occurs on the critical buses due to loss of voltage (T.S. setpoint of 2300 Volts ± 5%). When Bus 1F (1G) is powered from the Startup or Normal transformer, a degraded voltage of 3880 for 12.5 ± 1.3 seconds will trip breaker 1FA (1GB) unless a RHR initiation signal is present, in which case the time delay drops to 7.5 ± 0.8 seconds.

1) All 4160V feeder breakers on the critical buses, except the feeders to the 480V critical buses (SS1F and SS1G) trip.

2) Since none of the feeder breakers on 480V 1F and 1G have undervoltage protection, all the 480 vac MCCs powered from these load centers will re-energize when power is restored, unless the diesel generators are providing power.

d. If the Emergency Transformer is available and secondary voltage is above 4330V, the emergency supply breakers (1FS and 1GS) to the 4160V critical buses will shut within one second. Following a load shed, the breakers on 4160V 1F and 1G will then automatically and sequentially shut to load the buses in a controlled manner (TABLE 6).

e. If there is a bus 1F/1G undervoltage condition (as defined by a loss of voltage, 2300 volts ± 5% in < 5 seconds) for > 5.5 seconds (e.g., 1FS/1GS breakers do not close), the following breakers will trip, if closed, from 480V switchgear bus 1F (1G):

1) CRD Pump A (B)
2) Station Air Compressor A (B)
3) MCC-OG1 (MCC-MR)
4) MCC-M (MCC-U)
5) MCC-N (MCC-V)
6) MCC-P (MCC-W)

(This provides an additional level of load shedding intended to protect the diesel generators, as they will be expected to re-energize buses 1F and 1G is this case. Each 4160V critical bus has its own, independent undervoltage/degraded voltage and load shedding/load sequence circuitry.)

f. Both DGs will start unloaded and must be manually shutdown.

g. Selected loads which do not have undervoltage trips must be placed in

Lesson Number: COR002-23-02	Revision: 36

LO-02a
SO-07i

4. Power Supplies

   RHR pumps A and B are powered from 4160V bus 1F. RHR pumps C and D are powered from 4160V bus 1G.

5. Each pump is controlled by a four position switch on Panel 9-3. The switch positions are PULL-TO-LOCK, STOP, AUTO, and START. The switch spring returns to the AUTO position from START and STOP.

   The pump starts when its respective control switch is placed to START or when started locally at its breaker.

LO-03a; 04i
LO-15a, b

   The pumps automatically start on LPCI initiation signal of high drywell pressure (≤ 1.84 psig) or low-low-low reactor vessel water level (≥ - 113 in.).

   a. With normal power available, pumps A and D start immediately and pumps B and C start after a 5 second time delay. This time delay prevents voltage dips on the 4160V emergency buses due to ECCS initiation.

LO-03f; 06i; 08a

   b. With a loss of off-site power, pumps A and D start immediately upon restoration of power, and pumps B and C start 5 seconds after the restoration of power. This time delay prevents overloading the emergency diesels due to ECCS initiation.

      NOTE - If the pump control switch is taken to the STOP position and released (AUTO after STOP) with an initiation signal present, the pump will stop and an amber PUMP STOP SIG SEALED-IN light above the control switch will illuminate. This light remains on as long as the LPCI signal is present. It resets automatically when the LPCI initiation signals are clear and the logic is reset by the operator. The amber light will also illuminate, even without an initiation signal present, any time the control switch is in STOP or placed in PULL-TO-LOCK. The light will go out once the switch is removed from these positions.

LO-08a
LO-15c

6. The RHR pump motor supply breaker will trip on the following:

   a. Electrical fault (overcurrent, ground, etc.).

   b. Low voltage on critical bus (. 2300V).

   c. MO-17, or MO-18, or the associated MO-15 valve not full open AND the associated MO-13 valve not full open.

ATTACHMENT 5 125 VDC PANEL AA-3 BREAKER CHECKLIST

125 VDC PANEL AA3 - (R-903-NE)
FED FROM 125 VDC DISTRIBUTION PANEL A(4)

BREAKER NUMBER	DESCRIPTION	NORMAL POSITION	PERFORMED BY	VERIFIED BY	COMMENTS
1	REACTOR RECIRCULATION PUMP MG SET 1A CONTROL CABINET 2-184-11A	ON			
2	480V SWITCHGEAR CRITICAL BUS 1F	ON			
3	250 VDC RCIC STARTER RACK	ON			
4	LRP-PNL-ANNCAB08 (R-903-SE); LRP-PNL-ANNCAB09 (R-903-NW); LRP-PNL-ANNCAB10 (R-932-F SWGR RM)	ON			
5	REACTOR BUILDING PERSONNEL AIRLOCK DOOR	OFF ON			NORMALLY OFF EXCEPT WHEN AIRLOCK IN USE PER PROCEDURE 2.1.6
6	4160V SWITCHGEAR CRITICAL BUS 1F	ON			
7	125 VDC PANEL CA	ON			
8	REACTOR RECIRCULATION PUMP MG SET 1A CONTROL CABINET 2-184-11A; ARI ATWS/RPT PANEL C22	ON			
9	SPARE	OFF			

PROCEDURE 2.2A_125DC.DIV1 REVISION 7 PAGE 9 OF 21

PROCEDURE 5.8 REVISION 45 PAGE 14 OF 29

ATTACHMENT 4 STOP AND PREVENT HARD CARD

2. PREVENT INJECTION

2.1 Prevent both RHR Subsystems by performing one of following in each loop:

2.1.1 Both RHR pumps secured with pumps in PULL-TO-LOCK.

2.2.8 RHR-MO-25A, INBD INJECTION VLV

2.2.8.1 Opens with its control switch on Panel 9-3 positioned to OPEN (spring return to AUTO) and with one of following permissives:

a. RHR-MO-27A, OUTBD INJECTION VLV, closed.

b. Reactor pressure ≤ 436 psig.

2.2.8.2 Opens when a LPCI initiation signal is present and reactor pressure is ≤ 436 psig.

2.2.8.3 Closes with its control switch on Panel 9-3 positioned to CLOSE, but the close signal is inhibited as long as the auto open signal is present.

Examination Outline Cross-Reference	Level	RO
295021 (APE 21) Loss of Shutdown Cooling / 4 Ability to determine and/or interpret the following as they apply to LOSS OF SHUTDOWN COOLING: AA2.06 Reactor pressure	Tier#	1
	Group#	1
	K/A #	295021 AA2.06
	Rating	3.2
	Revision	0
Revision Statement:		

Question 29

The plant is in Mode 3.

RHR Pump A was operating in Shutdown Cooling when it tripped due to a motor fault.

Reactor pressure rose to 80 psig, then pressure was lowered to 40 psig by the operator.

(1) Which one of the following valves automatically closed as a result of this transient?

AND

(2) To satisfy system logic ONLY, what is the MINIMUM action necessary to reopen that valve?

A. (1) RHR-MO-25A [Inbd Injection Vlv]
   (2) Place RHR-MO-25A control switch to OPEN

B. (1) RHR-MO-25A [Inbd Injection Vlv]
   (2) Place GROUP ISOL RESET CHANNEL A and B switches to GR 2, 3, 6, 7 RESET, then place RHR-MO-25A control switch to OPEN

C. (1) RHR-MO-18 [Shutdown Cooling RHR Supply Inbd Vlv]
   (2) Place RHR-MO-18 control switch to OPEN

D. (1) RHR-MO-18 [Shutdown Cooling RHR Supply Inbd Vlv]
   (2) Place GROUP ISOL RESET CHANNEL A and B switches to GR 2, 3, 6, 7 RESET, then place RHR-MO-18 control switch to OPEN

Answer: D
Explanation: RHR-MO-18 and RHR-MO-25A are both open when RHR Pump A is operating in SDC mode. RHR-MO-18 automatically closes on high reactor pressure, 72 psig, or a Group 2 isolation signal, low RPV level +3” or high DW pressure, 1.84 psig. RHR-

MO-25A only closes on a Group 2 isolation signal. No Group 2 isolation signal exists, so MO-25A is still open. Reactor pressure is above 72 psig, so MO-18 is closed.

The Reactor Pressure-High Function is provided to isolate the shutdown cooling portion of the Residual Heat Removal (RHR) System. This function is provided only for equipment protection to prevent an intersystem LOCA scenario. The Reactor Pressure High isolation is not considered part of PCIS Group 2, but PCIS Group 2 reset switches must be operated to reset this logic. Reactor Pressure below the high setpoint, 72 psig, is a permissive for opening SDC suction isolation valves MO-17 and MO-18.

Distracters:
Answer A part 1 is plausible because MO-25A is open for a return flow path when RHR Pump A is in SDC mode, and MO-25A automatically isolates on a Group 2 signal. Two Group 2 valves, MO-17 and MO-18 close on both a Group 2 signal and high reactor pressure. It is wrong because high reactor pressure, 72 psig does not close MO-25A. Part 2 is plausible because high reactor pressure is not a Group 2 signal and because some RHR logic, such as RHR injection valve reactor pressure low permissives do not seal-in but automatically reset when the condition clears. It is wrong because MO-25A does not close on high reactor pressure, 72 psig, in shutdown cooling mode.

Answer B part 1 is plausible and wrong for the reason given for distractor A. Part 2 is correct.

Answer C part 1 is correct. Part 2 is plausible and wrong for the reason given for distractor A.

Technical References: Procedures 2.4SDC [Shutdown Cooling Abnormal](Rev 17), 2.2.69.2 [RHR System Shutdown Operations](Rev 105)

References to be provided to applicants during exam: none

Learning Objective: INT032-01-26 EO-M: Given plant condition(s), determine from memory any automatic actions listed in the applicable Abnormal/Emergency Procedure(s) which will occur due to the event(s);

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(7)	
Level of Difficulty:	3	

SRO Only Justification:	N/A
PSA Applicability:	
Top 10 Risk Significant Systems – RHR, PCIS	

CNS OPERATIONS MANUAL ABNORMAL PROCEDURE 2.4SDC SHUTDOWN COOLING ABNORMAL	USE: CONTINUOUS QUALITY: QAPD RELATED EFFECTIVE: 2/13/19 APPROVAL: ITR-RDM OWNER: OSG SUPV DEPARTMENT: OPS

1. ENTRY CONDITIONS

   1.1 Reduction in RPV cooldown rate.

   1.2 Rise in RPV pressure while in SDC.

   1.3 Lowering RPV water level while in SDC.

   1.4 Operating RHR pump trip while in SDC.

2. AUTOMATIC ACTIONS

   2.1 If PCIS Group 2 or 72 psig high pressure isolation has occurred:

      2.1.1 RHR-MO-17, SHUTDOWN COOLING RHR SUPPLY OUTBD VLV, closes.

      2.1.2 RHR-MO-18, SHUTDOWN COOLING RHR SUPPLY INBD VLV, closes.

   2.2 If PCIS Group 2 has occurred, RHR-MO-25A and/or RHR-MO-25B, INBD INJECTION VLV(s), close.

3. IMMEDIATE OPERATOR ACTION

   3.1 None.

4. SUBSEQUENT OPERATOR ACTION

   4.1 Record current time and date. Time/Date: ________/__________

   4.2 Suspend all movement of irradiated fuel and suspend all movement of heavy loads over irradiated fuel until SDC is restored.

NOTE – If RHR-MO-25A or RHR-MO-25B are closed when RHR System temperature exceeds 200°F, cooldown of RHR-MO-25A(B) could exceed 100°F and then thermal binding could occur. This condition is most likely to occur following valve isolation while in shutdown cooling at elevated RPV Coolant temperatures. To avoid thermal binding, valve is cycled within 2 hours of closure and prior to exceeding a 100°F RPV cooldown of valve.

4.3 IF RHR-MO-25A(B), INBD INJECTION VLV(s), is closed when RHR System temperature exceeds 200°F, THEN ensure valve(s) are cycled as follows:

4.3.1 Within 2 hours of closure.

4.3.2 Prior to exceeding 100°F RPV cooldown. Ⓟ[3]

4.4 Monitor following temperatures and pressures frequently until SDC is restored:

4.4.1 IF a RR pump is in service, THEN monitor RR-TI-151A(B), SUCT TEMP (PNL 9-4).

4.4.2 IF a RR pump is not in service, THEN monitor RPV metal temperatures on NBI-TR-89, REACTOR VESSEL METAL TEMPERATURE RECORDER (PNL 9-21), for indications of stratification and approach to boiling.

4.4.3 IF RWCU is in service, THEN monitor inlet temperature on RWCU-TI-137, TEMP IND, using Point 1 on TEMP POINT SELECTOR (PNL 9-4).

4.4.4 Monitor following reactor pressure PMIS Points for indication of pressurization:

4.4.4.1 B025.

4.4.4.2 N013.

4.4.4.3 N014.

4.5 IF SDC isolated due to PCIS Group 2 or 72 psig signal, THEN go to Step 4.10.

4.6 IF a RHR pump tripped and no SDC valves isolated, THEN perform Step 4.7 for Loop A or Step 4.8 for Loop B.

4.9 IF a RHR heat exchanger or service water malfunction exists, THEN concurrently perform Attachment 1 (Page 8).

4.10 IF RHR cannot be placed in SDC, THEN concurrently enter Attachment 2 (Page 9).

4.11 IF RHR Subsystem is required for LPCI injection, THEN perform applicable Attachment.

RHR Subsystem A	Attachment 3	Page 12
RHR Subsystem B	Attachment 4	Page 14

4.12 WHEN condition resolved and isolation signal is clear, THEN proceed in this section.

4.13 IF SDC lost due to PCIS Group 2, THEN perform following:

4.13.1 Ensure both LOOP A INITIATION LOGIC and LOOP B INITIATION LOGIC is reset by pressing both RESET buttons (PNL 9-3).

4.13.2 Press CONTAINMENT SPRAY INITIATION SIGNAL S33A(B) button.

4.13.3 Place GROUP ISOL RESET CHANNEL A and GROUP ISOL RESET CHANNEL B switches to GR 2, 3, 6, 7 RESET (PANEL 9-5).

4.13.3.1 Check Group 2, CHANNEL A Isolation lights turn on (PANEL 9-5).

4.13.3.2 Check Group 2, CHANNEL B Isolation lights turn on (PANEL 9-5).

4.13.4 Press SDC ISOL RESET VLV 25A(B) button (PNL 9-3).

4.14 IF SDC lost due to 72 psig signal, THEN place GROUP ISOL RESET CHANNEL A and GROUP ISOL RESET CHANNEL B switches to GR 2, 3, 6, 7 RESET (PANEL 9-5).

4.14.1 Check Group 2, CHANNEL A Isolation lights turn on.

4.14.2 Check Group 2, CHANNEL B Isolation lights turn on.

4.15 Place switch for selected RHR pumps to TRIP and then release to ensure breaker anti-pumping is reset (PNL 9-3).

4.16 Place RHR Subsystem in SDC Mode per Procedure 2.2.69.2.

4.17 IF RHR Subsystem is to be returned to LPCI standby lineup, THEN ensure system lineup is correct per Procedure 2.2.69.

3.10 Close RHR-MO-66A, HX BYPASS VLV.

3.11 Tag following components as specified:

3.11.1 RHR-MO-16A switch CLOSED (spring returns to AUTO).

3.11.2 At MCC-Q (R-903-N), Breaker 4D for RHR-MO-16A to OFF. ⓟ[10]

3.11.3 RHR-MO-16A handwheel DO NOT OPERATE.

3.12 Close RHR-MO-13A, PUMP A TORUS SUCT VLV.

3.13 Close RHR-MO-13C, PUMP C TORUS SUCT VLV.

3.14 Open RHR-MO-15A, PUMP A SDC SUCT VLV.

3.15 Open RHR-MO-15C, PUMP C SDC SUCT VLV.

3.16 IF all of following met, THEN go to Step 3.34:

3.16.1 SDC has been out of service for a short time.

3.16.2 RHR-MO-17, SHUTDOWN COOLING RHR SUPPLY OUTBD VLV, open.

3.16.3 RHR-MO-18, SHUTDOWN COOLING RHR SUPPLY INBD VLV, open.

3.17 IF SDC has been out of service for a short time, THEN perform following:

NOTE – Reactor high pressure (≤ 72 psig) isolation of RHR-MO-17 and RHR-MO-18 is not developed or actuated by PCIS Group 2 logic, but reset feature is fed through PCIS Group 2 RESET switches.

3.17.1 Place GROUP ISOL RESET CHANNEL A and CHANNEL B switches to GR 2, 3, 6, 7, RESET.

3.17.2 Ensure CM-P-RX, RX BLDG AUX COND PMP, running.

3.17.3 Open RHR-96, RHR SHUTDOWN COOLING CONDENSATE SUPPLY SHUTOFF (R-881-NW Quad).

3.17.4 Open RHR-97, RHR SHUTDOWN COOLING CONDENSATE SUPPLY ROOT (R-881-NW Quad).

3.17.5 Ensure RHR-MO-18 open.

3.17.6 Ensure RHR-MO-17 open.

3.17.7 (Independent Verification) Close RHR-97. Performed By: ________

Verified By: ________

Examination Outline Cross-Reference	**Level**	RO
290003 (SF9 CRV) Control Room Ventilation Ability to monitor automatic operations of the CONTROL ROOM HVAC including: A3.01 Initiation/reconfiguration	**Tier#**	2
	Group#	2
	K/A #	290003 A3.01
	Rating	3.3
	Revision	
Revision Statement:		

Question 30

The plant is in Mode 5.

A Control Room Emergency Filtration System (CREFS) initiation signal is received.

One minute later, the operator observes the following status of Control Room ventilation components:

- HV-270AV, CONTROL ROOM HVAC INLET VALVE is open
- HV-271AV, CONTROL ROOM HVAC EMER BYPASS VLV is open
- HV-272AV, CONTROL ROOM PANTRY EXH FAN ISOL SYSTEM is open

Which of the above listed components is/are **in** the **required** position?

A. HV-270AV, **only**

B. HV-271AV, **only**

C. HV-270AV **and** HV-272AV, **only**

D. HV-271AV **and** HV-272AV, **only**

Answer: B
Explanation: This question is a modified version of 9/2018 ILT NRC Q#65. The stem was modified to ask which components are in the required position (Answer B). The 2018 question asked which components are **NOT** in the required position (answer C).

Control Room Emergency Filtration (CREF) system initiates automatically from a Group 6 isolation. When CREF initiates, control room ventilation reconfigures as follows:

- BF-C-1A, EMER BSTR FAN starts
- EF-C-1B, TOILET EXHAUST FAN, trips
- HV-270AV, CONTROL ROOM HVAC INLET VALVE, closes
- HV-271AV, CONTROL ROOM HVAC EMERGENCY BYPASS SYSTEM INLET VALVE, opens
- HV-272AV, CONTROL ROOM PANTRY EXHAUST FAN ISOLATION VALVE, closes

Therefore, only HV-271AV should be open.

Distracters:
Answer A is plausible to the examinee who does not know the arrangement of control HVAC components or system response to CREF initiation. The examinee may believe HV-270AV is necessarily open to provide an inlet for the AC unit. This answer is wrong because HV-270AV should be closed.

Answer C is plausible to the examinee who does not know the arrangement of control HVAC components or system response to CREF initiation and believes HV-270AV is necessarily open to provide an inlet for the AC unit, and HV-272AV should be open to create a negative pressure atmosphere, similar to SGT, not knowing the system is designed to create a positive pressure atmosphere to prevent inleakage of radioactive gases. This answer is wrong because HV-270AV and 272AV should be closed.

Answer D is plausible to the examinee who does not know the arrangement of control HVAC components or system response to CREF initiation and believes HV-272AV should be open to create a negative pressure atmosphere, similar to SGT, not knowing the system is designed to create a positive pressure atmosphere to prevent inleakage of radioactive gases. This answer is wrong because HV-272AV should be closed.

Technical References: Procedure 2.1.22 [Recovering from a Group Isolation](Rev 62), lesson plan COR001-08-01 [OPS Heating, Ventilation and Air Conditioning](Rev 28)

References to be provided to applicants during exam: none

Learning Objective: COR001-08-01 Obj LO-12a, Describe the Control Room HVAC design features and interlocks that provide for the following: Control Room HVAC reconfigurations

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	9/2018 ILT NRC Q#65
	New	

Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(7)	
Level of Difficulty:	2	
SRO Only Justification:	N/A	
PSA Applicability		
N/A		

9/2019 NRC Q#65

Question 65

The plant is in Mode 5.

Reactor Building Exhaust Plenum Radiation rises to 50 mR/hr due to a fuel handling accident.

One minute later, status of Control Room ventilation components are as follows:

- HV-270AV, CONTROL ROOM HVAC INLET VALVE is open
- HV-271AV, CONTROL ROOM HVAC EMER BYPASS VLV is open
- HV-272AV, CONTROL ROOM PANTRY EXH FAN ISOL SYSTEM is open

Which of the above listed components is/are NOT in the required position?

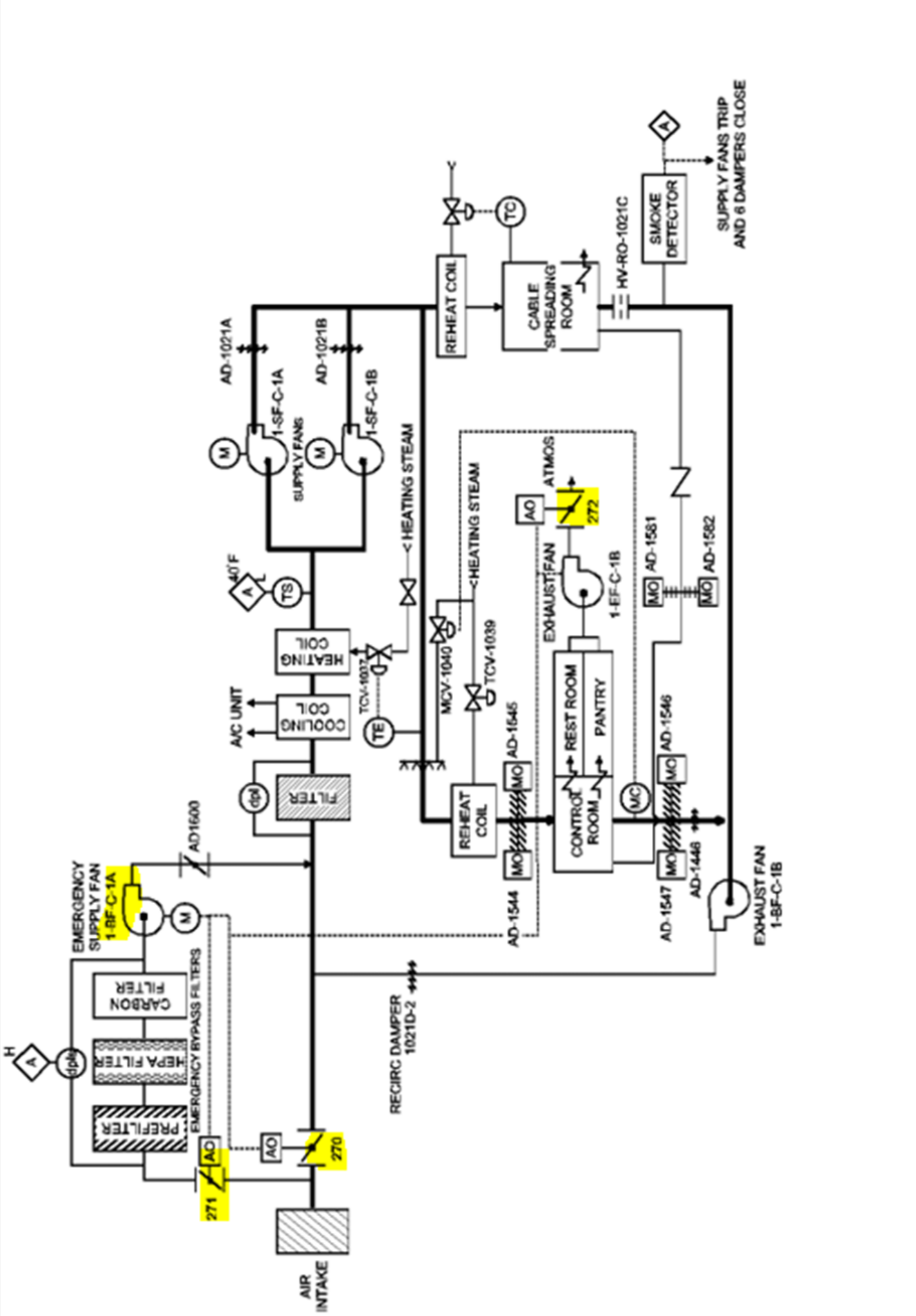
A. HV-270AV, **only**

B. HV-271AV, **only**

C. HV-270AV **and** HV-272AV, **only**

D. HV-271AV **and** HV-272AV, **only**

Answer: C



MAIN CONTROL ROOM AIR CONDITIONING SYSTEM

Figure 23, Rev. 6

COR001-08

9.2 IF Primary Containment inerting was in-progress, THEN perform following:

CAUTION – Rupture disc on N_2 inerting line may have blown causing life-threatening atmosphere at R-903-SW area.

NOTE – Rupture disc PC-RD-NPS opens at 60 psig.

9.2.1 IF full Group 6 Isolation, THEN check N_2 flow on PC-FI-515, N_2 FLOW (VBD-H).

9.2.1.1 IF N_2 flow > 0 cfm, THEN assume rupture disc blown and perform following:

NOTE – Steps 9.2.1.1a through 9.2.1.1c may be performed concurrently.

a. Evacuate Reactor Building by making gaitronics announcement.

b. Inform Shift Manager/Control Room Supervisor of condition.

c. Control access to Reactor Building such that personnel entering building shall wear SCBAs until O_2 concentrations in building have been ensured.

9.2.1.2 At N_2 storage tank, close N2-99, NITROGEN SUPPLY ROOT ISOLATION VALVE.

9.2.1.3 Shut down Primary Containment N_2 Inerting System per Procedure 2.2.60.

9.3 Upon full Group 6 Isolation, ensure following actions have occurred:

9.3.1 Following primary containment purge ventilation isolation valves are closed (VBD-H):

9.3.1.1 PC-AO-246, DW EXH OUTBD ISOL VLV.

9.3.1.2 PC-MO-231, DW EXH INBD ISOL VLV.

9.3.1.3 PC-MO-306, VALVE MO 231 BYPASS VLV, if ISOLATION OVERRIDE control switch on Panel P1 is not in OVERRIDE.

9.3.1.4 PC-MO-232, DW INLET INBD ISOL VLV.

9.3.1.5 PC-AO-238, DW INLET OUTBD ISOL VLV.

9.3.1.6 PC-MO-233, TORUS INLET INBD ISOL VLV, if ISOLATION OVERRIDE switch on Panel P2 is not in OVERRIDE.

9.3.1.7 PC-AO-237, TORUS INLET OUTBD ISOL VLV, if ISOLATION OVERRIDE switch on Panel P2 is not in OVERRIDE.

9.3.1.8 PC-AO-245, TORUS EXH OUTBD ISOL VLV.

9.3.4 Following RRMG Set exhaust fans have tripped and isolation valves have closed (VBD-R):

9.3.4.1 EF-R-1C, EXH FAN (BOTTOM).

9.3.4.2 EF-R-1D, EXH FAN (TOP).

9.3.4.3 HV-AO-263, MG SET-1A INLET VLV.

9.3.4.4 HV-MO-262, MG SET-1A INLET VLV.

9.3.4.5 HV-AO-267, MG SET-1A OUTLET VLV.

9.3.4.6 HV-MO-266, MG SET-1A OUTLET VLV.

9.3.4.7 HV-AO-265, MG SET-1B INLET VLV.

9.3.4.8 HV-MO-264, MG SET-1B INLET VLV.

9.3.4.9 HV-AO-269, MG SET-1B OUTLET VLV.

9.3.4.10 HV-MO-268, MG SET-1B OUTLET VLV.

9.3.5 Control Room Emergency Filter System (CREFS) starts (VBD-R):

9.3.5.1 BF-C-1A, EMER BSTR FAN, starts.

9.3.5.2 EF-C-1B, TOILET EXH FAN, stops.

9.3.5.3 HV-270AV, CONTROL ROOM HVAC INLET VALVE, closes.

9.3.5.4 HV-271AV, CONTROL ROOM HVAC EMERGENCY BYPASS SYSTEM INLET VALVE, opens.

9.3.5.5 HV-272AV, CONTROL ROOM PANTRY EXHAUST FAN ISOLATION VALVE, closes.

9.3.6 Following REC and SW valves are open (VBD-M):

9.3.6.1 REC-MO-711, NORTH CRITICAL LOOP SUPPLY VLV.

9.3.6.2 SW-MO-650, REC HX A SERVICE WATER OUTLET (intermediate open if valve was closed before isolation occurred).

9.3.6.3 REC-MO-714, SOUTH CRITICAL LOOP SUPPLY VLV.

9.3.6.4 SW-MO-651, REC HX B SERVICE WATER OUTLET (intermediate open if valve was closed before isolation occurred).

9.4 Align SGT per Procedure 2.2.73 within 1 hour of receiving Group 6.6[1]

9.5 Monitor RRMG Set temperatures closely and take action per Procedure 2.4HVAC.

Lesson Number: COR001-08-01	Revision: 26

Tile/Location	Initiating Device/ Setpoint	Additional Functions
g. CONTROL ROOM MONITOR TROUBLE/ Panel Q, Q-1/B-2	RMV-CAM-20/ Local Trouble Alarm	None
h. CONTROL ROOM BOOSTER FAN BF-C-1B NOT RUNNING/ Panel R, R-1/D-5	HV-STR-BF-Cb Fails to run when switch in RUN, or switch is OFF	None

6. Interlocks and Trips

LO-11a,b,c,d; 12a,b
LO-22d; SO-07h; SO-09a,b,c,d

Interlock/Trip	Initiating Device/ Setpoint	Additional Functions
a. Control Room Emergency Filtration System (CREFS)	PCIS GROUP 6 Isolation a) Reactor Building ventilation exhaust plenum ≤ 49 mr/hr b) all four Reactor High drywell pressure ≤+1.84 psig c) Low reactor water level ≥ - 42.0"	CREFS initiates by; 1. EF-C-1B, TOILET EXHAUST FAN, trips. 2. HV-270AV, CONTROL ROOM HVAC INLET VALVE, closes. 3. HV-271AV, CONTROL ROOM HVAC EMERGENCY BYPASS SYSTEM INLET VALVE, opens. 4. HV-272AV, CONTROL ROOM PANTRY EXHAUST FAN ISOLATION VALVE, closes. 5. BF-C-1A, EMERGENCY BOOSTER FAN, starts
b. Smoke Detector Actuation in Main Control Room Ventilation System	SD-1001/smoke detected	Once reset, fans restart and fire smoke damper open if control switch position is unchanged.

Lesson Number:	COR001-08-01	Revision: 26

Interlock/Trip	Initiating Device/ Setpoint	Additional Functions
g. Battery Room Isolation Dampers	HV-TS-866 100ºF (HV-TS-867) HV-TS-868 80ºF (HV-TS-869)	High temp in battery room 1A(1B) opens damper Low temp in battery room 1A(1B) closes damper
h. Smoke Detector Actuation in Control Building	SD-1003/smoke detected	Once reset, fans restart if control switch position is unchanged.

Fig 23
LO-01b,c

W. Main Control Room Air Conditioning System

The system provides HVAC to the Control Room and Cable Spreading Room for personnel comfort and optimum equipment performance. This system consists of an emergency bypass suction line with a filter train and supply fan, a manual outlet damper valve locked in a throttled position, an air conditioning unit with a normal suction line, and two exhaust fans. Also discussed under this topic is the air conditioning unit which supplies the cable expansion room.

LO-06a,08c
LO-07f
SO-03c, 05k |

1. Control Room Emergency Filtration System (CREFS)

The Control Room Emergency Filtration System contains an emergency filter train and a supply fan (BF-C-1A). The filter train is made up of a prefilter, high efficiency filter, and a carbon filter. The emergency supply fan draws air in from the outside, through the filters, and then discharges to the suction of the AC unit. This fan can be powered from either Div. I (MCC-LX-normal) or Div II (MCC-TX-alternate) critical power. Operator action of manual transfer switch HV-SW-(BF-C-1A/1B) in the Aux. Relay room is required to transfer the power between Div I and Div II. This transfer is performed "dead bus", by opening both supply breakers and locking open the breaker from the MCC not to be used before shifting the transfer switch, then closing the supply from the MCC selected to supply power. Shifting this transfer switch also transfers power for booster fan BF-C-1B.

LO-10c, 14b

The emergency bypass supply fan is intended to prevent the introduction of unfiltered air into the Control Room envelope

Lesson Number:	COR001-08-01	Revision: 26

(which includes the cable spreading room) by maintaining the Control Room envelope at a positive pressure as compared to the adjoining buildings and the outside atmosphere under calm wind conditions.

LO-10a, 14a

The PCIS group 6 isolation signal is an indicator of a Loss of Coolant Accident or Fuel Handling accident. Combining the group 6 isolation signal with the rapid stroke times of the isolation valves, ensure dose for Control Room personnel to remain below limits.

LO-06g,10a, 12a
SO-7c, 9c, d
LO-14a; 20a,c; 22a

Upon PCIS a group 6 isolation, an alarm is annunciated in the Control Room, and the emergency supply fan starts. Once the fan starts, the intake valves automatically shift to ensure that all outside air passes through the filter train. Another valve which also repositions is the kitchen/toilet exhaust valve (closes). If the emergency supply fan fails to start, then the dampers will not shift. Also the pantry/toilet exhaust fan is interlocked to trip whenever the emergency supply fan starts.

SO-08
LO-10a,14b, 21

In the event that a Control Room envelope door is blocked open or is otherwise damaged, the Control Room Emergency Filter System must be considered inoperable.

LO-10a,14a

A Continuous Air Monitor (CAM), located in the Control Room, provides indication of control room habitability. Upon high airborne or iodine condition, the CAM unit will locally alarm and cause Annunciator Q-1/A-2 to alarm. The operator will be directed by procedure to place CREFS into service.

2. Air Conditioning Unit (AC-C-1A)

The Control Room AC unit draws in air from the outside and from the discharge of the systems exhaust fan (recirculated air). If it comes from outside, it normally just passes through an isolation damper, but in an emergency (high radiation), the air passes through the emergency bypass filter train prior to entering the AC unit.

LO-10b, 14c

The AC unit contains a filter, cooling coil, heating coil, refrigeration compressors, and two supply fans with outlet dampers. Both fans are capable of supplying 100% of the air requirements for the Control Room and the cable

Examination Outline Cross-Reference	Level	RO
256000 (SF2 CDS) Condensate Ability to predict and/or monitor changes in parameters associated with operating the REACTOR CONDENSATE SYSTEM controls including: A1.07 System lineup	Tier#	2
	Group#	2
	K/A #	256000 A1.07
	Rating	3.1
	Revision	0
Revision Statement:		

Question 31

Plant is in Mode 1 with the following conditions:

- Condensate Pumps B and C are running.
- Condensate Booster Pumps B and C are running.
- Condensate Booster Pump suction header pressure is 65 psig.

The Condensate Booster Pump A control switch is placed in START.

Which one of the following completes the statement below?

When Condensate Booster Pump A control switch is placed in START, the pump will.....

A. NOT start because less than three condensate pumps are running.

B. NOT start because the low suction pressure interlock has not been met.

C. start, but then, if suction pressure falls below 25 psig, it will trip 9 seconds later.

D. start, but then, if suction pressure falls below 25 psig, it will trip 12 seconds later.

Answer: C

Explanation:
Starting interlocks for CBPs require suction pressure > 50 psig and pump lube oil pressure > 5psig. In the stem, suction pressure is >50 psig, so CBP A will start.

CBPs trip if suction pressure falls to < 25 psig after a time delay of 9 seconds for Pump A, 12 seconds for Pump B, and 15 seconds for Pump C.

Distracters:
Answer A is plausible because previously, the number of running CPs were inputs to starting interlocks for CBPs. Until recently (10-25-18), for 1st CBP being started at least one CP had to be running, and for 2nd and 3rd CBPs being started required at least two CPs operating for the CBP to start. Now, 1st, 2nd and 3rd CBPs being placed into operation will start irrespective of the number of CPs running. The examinee who believes a CBP starting is contingent upon the number of CPs running may choose this answer. It is wrong because CBP starting interlocks are not dependent on the number of CPs running.

Answer C is plausible because CBPs will not start if suction pressure is below the starting interlock setpoint. It is wrong because suction pressure is above the starting interlock setpoint, 50 psig.

Answer D is plausible because CBPs sequentially trip on low suction pressure <25 psig based on assigned time delays of 9, 12, or 15 seconds. CBP C trips after a 12 second time delay. It is wrong because CBP A trips after a 9 second time delay when pressure is suction pressure falls below 25 psig.

Technical References: procedure 2.2.6 [Condensate System](Rev 98), CED 6024460

References to be provided to applicants during exam: none

Learning Objective: COR0020202001060A Describe the Condensate and Feedwater design features and/or interlocks that provide for the following: Condensate and Booster Pump interlocks

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	12/2015 ILT NRC Q#62
	New	
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(7)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	

PSA Applicability:
N/A

12/2015 ILT NRC Q#62

Question 62

A plant startup is in progress with the following conditions:

- Condensate Pump A is running.
- Condensate Booster Pump C is running.
- Condensate Booster Pump Suction Pressure is 55 psig.

The Condensate Booster Pump B control switch is placed in START.

Which one of the following completes the statement below?

If Condensate Booster Pump B control switch is placed in START, the pump will.....

A. NOT start because less than two condensate pumps are running.

B. NOT start because the low suction pressure interlock has not been met.

C. start, but then, if suction pressure falls below 25 psig for AT LEAST 9 seconds, will trip.

D. start, but then, if suction pressure falls below 25 psig for AT LEAST 12 seconds, will trip

Answer:
A. NOT start because less than two condensate pumps are running.

CNS OPERATIONS MANUAL SYSTEM OPERATING PROCEDURE 2.2.6 CONDENSATE SYSTEM	USE: REFERENCE QUALITY: QAPD RELATED EFFECTIVE: 10/25/18 APPROVAL: ITR-RDM OWNER: OSG SUPV DEPARTMENT: OPS

REVISION VERIFICATION:
(initial use + every 7 days)

REV.	DATE	CHANGES
97	9/20/18	Added guidance to check condensate booster pump minimum flow is ready to close in Sections 8 and 10.
98	10/25/18	Updated guidance due to removal of auxiliary switches from condensate and condensate booster pump breakers, which removes multiple pump interlocks. CED 6024460.

ATTACHMENT 2 INFORMATION SHEET

2. INTERLOCKS AND SETPOINTS

2.1 The first condensate booster pump will start when its switch is placed to START if the following conditions are satisfied:

2.1.1 Pump suction pressure > 50 psig.

2.1.2 Pump oil pressure > 5 psig.

2.2 The second and third condensate booster pump starts when its switch on is placed to START if the following conditions are satisfied:

2.2.1 Pump suction pressure > 50 psig.

2.2.2 Pump oil pressure > 5 psig.

2.3 A condensate booster pump will trip if any of the following conditions occur:

2.3.1 All condensate pumps are not running.

2.3.2 Pump oil pressure < 3 psig.

2.3.3 Condensate booster pump suction pressure < 25 psig after a time delay of 9 seconds for Pump A, 12 seconds for Pump B, and 15 seconds for Pump C.

2.4 A condensate booster pump auxiliary oil pump will start if the following conditions are satisfied:

2.4.1 Control switch is in AUTO.

2.4.2 Pump oil pressure is 5 psig.

2.5 MC-FCV-17, CONDENSATE MINIMUM FLOW CONTROL VLV, opens on system low flow of 4000 gpm.

2.6 MC-FCV-17 closes when system flow > 4000 gpm and RESET button is pressed.

2.7 MC-PC-9A and 9B, CONDENSATE PUMPS MINIMUM FLOW VLV A and B, open and close to maintain at least 6000 gpm flow per operating condensate pump.

2.8 MC-FCV-8(10, 12), CONDENSATE BOOSTER PUMP A(B, C) MINIMUM FLOW VLV, opens on Condensate Booster Pump A(B, C) discharge flow of 1600 gpm.

2.9 MC-FCV-8(10, 12) closes when Condensate Booster Pump A(B, C) discharge flow > 1600 gpm and RESET button is pressed. There is no direct indication of individual booster pump discharge flow, but that acceptable flow to reset the minimum flow can be determined by MC-DPIS-8(10, 12) indicating > 15" H_2O or RVLC MIMIC indicating HIGH for COND BST PMP A(B, C).

2.10 MC-FCV-8(10, 12) closes when breaker for Condensate Booster Pump A(B, C) open.

Examination Outline Cross-Reference	Level	RO
295024 High Drywell Pressure / 5 Knowledge of the reasons for the following responses as they apply to HIGH DRYWELL PRESSURE: EK3.06 Reactor SCRAM	Tier#	1
	Group#	1
	K/A #	295024 EK3.06
	Rating	4.0
	Revision	0
Revision Statement:		

Question 32

Regarding the reasons for a manual scram due to high drywell pressure during a LOCA…

(1) Procedure 2.4PC [Primary Containment Control] states:

"If drywell pressure <u>cannot</u> be maintained ≤ ________ psig, THEN SCRAM and enter Procedure 2.1.5."

AND

(2) What is the reason stated in Procedure 2.4PC for this scram action?

A. (1) 0.75
(2) It is preferable to insert a manual scram rather than to allow an automatic scram to occur

B. (1) 0.75
(2) To avoid initiation of safety systems by reducing the amount of energy that must be absorbed by primary containment

C. (1) 1.5
(2) It is preferable to insert a manual scram rather than to allow an automatic scram to occur

D. (1) 1.5
(2) To avoid initiation of safety systems by reducing the amount of energy that must be absorbed by primary containment

Answer: C
Explanation: Procedure 2.4PC step 4.2 requires the operator to insert a manual scram if DW pressure cannot be maintained ≤1.5 psig. 2.4PC Attachment 2 step 1.3 states scram

action: "If drywell pressure cannot be maintained ≤ 1.5 psig" is based on actual trip setpoints, setpoint tolerances, and to allow a reasonable pressure range for recovery. Per Operations policy, it is preferable to initiate a Manual Scram rather than allow an Automatic Scram to occur. USAR Section VII-2.3.6.8 states a high pressure inside the drywell could indicate a break in the reactor coolant pressure boundary. It is prudent to scram the reactor in such a situation to minimize the possibility of fuel damage and to reduce the addition of energy from the core to the coolant. USAR Section XIV-6.3.7.1 states the reactor is assumed to be scrammed at the time of accident initiation in less than one second from receipt of the high drywell pressure signal. Part 2 is design bases question.
Distracters: Answer A part 1 is plausible because 0.75 psig is the TS 3.6.1.4 limit for DW pressure and because procedure 2.4PC requires a rapid power reduction if DW pressure cannot be maintained below that value. It is wrong because 1.5 psig is the scram criteria per procedure 2.4PC. Part 2 is correct. Answer B part 1 is plausible and wrong for the reason stated for distractor A. Part 2 plausible because 2.4PC contains actions to attempt to avert reaching the ESF initiation setpoint (i.e. venting containment). Also, the high DW pressure automatic scram is assumed in the USAR accident analysis to trip the reactor and functions to minimize the energy absorbed by the coolant and transmitted to the containment during large break LOCAs. It is wrong because scramming alone does not reduce reactor pressure; therefore, it does not reduce the driving head of a LOCA, so the ESF initiation setpoint may still be exceeded. It is not the reason for the criteria in the stated scram action listed in procedure 2.4PC. Answer D part 1 is correct. Part 2 is plausible and wrong for the reason stated for distractor B.
Technical References: Lesson plan INT006-01-18 [Ops Accident Analysis](Rev 11), CNS USAR XIV Section 6.3, Procedure 2.4PC [Primary Containment Control](Rev 21)
References to be provided to applicants during exam:
Learning Objective: INT007-05-04 EO-2, Discuss the applicable Safety Analysis in the Bases associated with each Section 3.3 Specification ; COR002-21-02 Obj LO-1d, State the purpose of the following items related to RPS: RPS logic channels; 10k, Describe the interrelationship between the RPS and the following: Primary Containment; INT006-01-18 EO-2, Given an accident and a set of conditions, select those conditions that would tend to make the consequences of the given accident more severe.

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	

	New	X
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(5),(6),(10)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA Applicability:		
Top 10 Risk Significant System - RPS		

CNS OPERATIONS MANUAL ABNORMAL PROCEDURE 2.4PC PRIMARY CONTAINMENT CONTROL	USE: CONTINUOUS QUALITY: QAPD RELATED EFFECTIVE: 12/18/19 APPROVAL: ITR-RDM OWNER: AOM-SUPPORT DEPARTMENT: OPS

Scram Actions

1. ENTRY CONDITIONS
   1.1 PC pressure rising.
   1.2 PC temperature rising.
   1.3 PC radiation level rising.
   1.4 DW FCU(s) trip.
   1.5 DW sump pumps operating more than usual.
2. AUTOMATIC ACTIONS
   2.1 None.
3. IMMEDIATE OPERATOR ACTIONS
   3.1 None.
4. SUBSEQUENT ACTIONS
   4.1 Record current time and date. Time/Date: ________/________
   4.2 **IF while performing this procedure, drywell pressure <u>cannot</u> be maintained ≤ 1.5 psig, THEN SCRAM and enter Procedure 2.1.5.**

<u>CAUTION</u> – If RB HVAC Isolation signals have been over ridden per Procedure 5.8.20 (EOP PTM 53, 54, 55, and 56), then containment venting per Procedure 2.2.60 is <u>not</u> allowed.

<u>NOTE</u> – Steps 4.3 through 4.8 may be performed concurrently.

Scram Actions

   4.3 Maintain drywell pressure below 0.75 psig by venting containment through SGT System per Procedure 2.2.60.
   4.4 IF drywell pressure <u>cannot</u> be maintained less than or equal to 0.75 psig, THEN enter Conditions and Required Actions of LCO 3.6.1.4.
   4.5 IF drywell pressure <u>cannot</u> be restored <u>and</u> maintained below 0.75 psig, THEN perform rapid power reduction per Procedure 2.1.10.
   4.6 Ensure all available drywell FCU control switches in RUN.

ATTACHMENT 2 INFORMATION SHEET

ATTACHMENT 2 INFORMATION SHEET

1. DISCUSSION

1.1 The major concern of high drywell temperatures is the effect elevated temperatures can have on RPV water level indications. Primary Containment structure design temperature is 281°F, but EQ equipment in the drywell is qualified for the most limiting postulated DBA which includes peak temperatures of 340°F. Environmental excursions beyond the postulated DBA profile may result in failure of safety-related equipment.

1.2 A total loss of drywell coolers, during power operation, will cause bulk drywell air temperature to initially rise rapidly. Reactor scram on high drywell pressure will occur in several minutes.

1.3 The scram action: *"If drywell pressure cannot be maintained ≤ 1.5 psig"* is based on actual trip setpoints, setpoint tolerances, and to allow a reasonable pressure range for recovery. Per Operations policy, it is preferable to initiate a Manual Scram rather than allow an Automatic Scram to occur.

1.4 Various indications may be used to identify or verify potential leakage from the RCS into the drywell. They include drywell sump flow indications, drywell temperature indications, drywell radiation indications, and drywell relative humidity determination. The trend in drywell relative humidity level is not the most direct indication of steam leakage into the drywell but may be used to verify other indications of potential steam leakage into the drywell. The drywell humidity may be determined by plotting drybulb (PC-TR-500A, PC-TR-500B, PC-TR-500C, PC-TR-500D) and wetbulb (PC-R-MR-500A, PC-R-MR-500B, PC-R-MR-500C, PC-R-MR-500D) temperatures on Attachment 1. A significant, short-term, increasing trend in relative humidity will most likely accompany the initiation of a steam leak in the drywell.

1.5 The two major sources of heat input to the drywell are radiant heat losses from the vessel and piping, and heat generated by the Reactor Recirculation pump motors. The heat generated by the RR pump motors is variable and is directly related to the power being consumed by the motor. Lowering reactor power with control rods does little to lower radiant heat input from the vessel and piping. Lowering RR pump speed to a core flow of 40×10^6 lbs/hr will lower the total heat input to the drywell by nearly two thirds of its value at 70×10^6 lbs/hr.

1.6 The drywell pressure of 0.75 psig is based on the Design Basis Accident (DBA) analysis and Technical Specification 3.6.1.4. The DBA assumes an initial drywell pressure of 0.75 psig. This limitation ensures the safety analysis remains valid by maintaining the expected initial conditions and ensures the peak LOCA drywell internal pressure does not exceed the maximum allowable of 62 psig.

USAR

6.3.6 Core and System Performance

For the short-term DBA scenario, the reactor will automatically scram due to high drywell pressure. Main steam line isolation will occur due to low reactor water level. No mechanical S/RV actuation will occur because of the rapid reactor vessel depressurization and large rate of reactor fluid and energy inventory loss through the break. Shortly after the postulated pipe break, the ECCS automatically begins to pump water from the plant emergency condensate storage tank and/or the suppression pool into the reactor pressure vessel to flood the reactor core. Following vessel flooding and drywell/wetwell airspace pressure equalization, suppression pool water is continually recirculated from the pool to the reactor vessel by the ECCS pumps. The core decay power results in a slow heat-up of the suppression pool. The suppression pool cooling mode of the RHR system is manually actuated to remove energy from the suppression pool to return the Primary Containment to normal temperature conditions.

For the long-term DBA scenario, the Core Spray system removes decay heat and stored heat from the core, thereby controlling core heatup and limiting metal-water reaction to less than 0.1 percent. The core spray water transports the core heat out of the reactor vessel through the broken recirculation line in the form of hot water.

As described in Chapter VI, analysis of the consequences of this accident demonstrates that the integrated performance of the ECCS in conjunction with restrictions on MAPLHGR will ensure compliance to the acceptance criteria of 10CFR50.46. These criteria have been established to prevent fuel damage as a result of this accident.

6.3.7 Barrier Performance (Primary Containment Response)

This section describes the analysis of Primary Containment response to a DBA LOCA event for Cooper Nuclear Station. There are two basic types of analyses, which use slightly different methods for the analysis. The short-term analysis, in USAR Section XIV-6.3.7.1, describes the calculation of peak Primary Containment pressure which occurs within the first 30 seconds. The long-term analysis, in USAR Section XIV-6.3.7.2, describes the calculation of pressure and temperature history in the drywell and suppression chamber for several minutes following the accident.

6.3.7.1 Short-Term Primary Containment Response Analysis

The following assumptions and initial conditions were used in calculating the effects of a LOCA on the Primary Containment during the initial 30 seconds following a DBA LOCA for the Mark I Containment Program.

a. The reactor is assumed to be scrammed at the time of accident initiation. Actually, scram will occur in less than one second from receipt of the high drywell pressure signal, but the difference in shutdown time between zero and one second is negligible.

b. The main steam line isolation valves were assumed to start closing at 0.5 seconds after the accident, and the valves were assumed to be fully closed in the shortest possible time of three seconds following closure initiation. Actually, the closures of the main steam line isolation valves are expected to be the result of low water level, so these valves may not receive a signal to close for over four seconds, and the closing time could be as high as 10 seconds. By assuming rapid closure of these valves, the reactor vessel is maintained at a high pressure, which maximizes the discharge of high energy steam and water into the Primary Containment.

USAR

2.3.6.7 Scram Discharge Volume High Water Level

Each SDV receives the water displaced by the motion of the control rod drive pistons during a scram. The SDVs are comprised of header piping, which is slightly sloped to promote draining of the SDVs to the Scram Discharge Instrument Volumes (SDIVs). The SDIVs provide a means of measuring the water level in the SDVs. Should the SDVs fill up with water to the point where not enough space remains for the water displaced during a scram, control rod movement would be hindered in the event a scram were required. To prevent this situation the reactor is scrammed when the water level in the SDIVs attains a value high enough to verify that the SDVs are filling up yet low enough to ensure that the remaining capacity in the SDVs can accommodate a scram. Prior to this level being reached, alarms and a control rod withdrawal block are generated to prevent further rod withdrawal which would necessitate more SDV capacity should a scram be required.

Per IEB 80-14 commitments, to ensure the SDV does not fill with water, the vent and drain valves are verified open at least once every 31 days. This is to preclude establishing a water inventory, which if sufficiently large, could result in slow scram times or only a partial control rod insertion.

The vent and drain valves shut on a scram signal thus providing a contained volume (SDV) capable of receiving the full volume of water discharged by the control rod drives at any reactor vessel pressure. Following a scram, the SDV is discharged into the reactor building drain system.

2.3.6.8 Drywell High Pressure

A high pressure inside the drywell could indicate a break in the reactor coolant pressure boundary. It is prudent to scram the reactor in such a situation to minimize the possibility of fuel damage and to reduce the addition of energy from the core to the coolant. The reactor vessel low water level scram also acts to scram the reactor for LOCAs. The drywell high pressure scram setting is selected to be as low as possible without inducing spurious scrams.

2.3.6.9 Manual Scram

The operator is provided with a means to shut down with RPS manual scram push buttons located in the control room.

2.3.6.10 Reactor Mode Selector Switch in Shutdown

The reactor mode selector switch provides appropriate protective functions for the condition in which the reactor is to be operated. The reactor is to be shut down with all control rods inserted when the mode selector switch is in SHUTDOWN. To enforce the condition defined for the SHUTDOWN position, placing the reactor mode selector switch in the SHUTDOWN position initiates a reactor scram. This scram is not considered a protective function because it is not required to protect the fuel or reactor coolant pressure boundary, and it bears no relationship to minimizing the release of radioactive material from any barrier. The scram signal is removed after a short time delay, which permits a scram reset. This reset allows normal valve lineup restoration in the control rod drive hydraulic system. Normal valve lineup restoration opens the SDV drain and vent valves to allow the SDV to be drained.

Examination Outline Cross-Reference	Level	RO
295007 (APE 7) High Reactor Pressure / 3 Ability to operate and/or monitor the following as they apply to HIGH REACTOR PRESSURE: AA1.05 Reactor/turbine pressure regulating system	Tier#	1
	Group#	2
	K/A #	295007 AA1.05
	Rating	3.7
	Revision	0
Revision Statement:		

Question 33

The plant is at 100% power when MSIV 86C fails closed.

Which one of the following describes the response of DEH control?

A. Turbine control valves throttle closed, then throttle open based on reactor pressure.

B. Turbine control valves throttle closed, then throttle open based on equalizing header pressure.

C. Turbine control valves throttle open, then throttle closed based on reactor pressure.

D. Turbine control valves throttle open, then throttle closed based on equalizing header pressure.

Answer: B

Explanation:
DEH is in Mode 4, Turbine Follow Reactor mode, at 100% power. Single MSIV closure at 70% power causes reactor pressure to rise ~15 psig, due to increased differential pressure across the remaining three open steam lines. In this transient reactor pressure remains below the scram setpoint, 1030 psig. Pressure downstream of the MSIVs lowers due to increased flow resistance caused by loss of 25% of the total cross-sectional area of the steam lines. Pressure in main steam equalizing header, therefore, lowers. DEH senses pressure in the equalizing header to control turbine governor valves and bypass valves. In DEH Mode 4, DEH responds by throttling turbine control valves closed to maintain pressure in the equalizing header at the DEH pressure setpoint. As reactor pressure rises due to closed MSIV, and flow increases in the other three MSLs, causing pressure in the equalizing header to rise, turbine control valves then throttle open to control equalizing header pressure.

Distracters:
Answer A is plausible because it reflects the actual response of TCVs. The examinee who believes DEH senses reactor pressure and remembers TCVs response from simulator training but who does not understand DEH operation may choose this answer. This answer is wrong because DEH control is based on feedback from pressure sensed from the equalizing header.

Answer C is plausible for the examinee who believes DEH senses reactor pressure. If DEH sensed reactor pressure, TCVs would throttle open, then closed. It is wrong because in DEH senses equalizing header pressure, and TCVs throttle closed, then open.

Answer D is plausible for the examinee who remembers DEH senses equalizing header pressure and does not understand how MSIV closure affects equalizing header pressure and reactor pressure or does not understand DEH control. It is wrong because TCVs first throttle closed due to lowering equalizing header pressure, then as reactor pressure rises and steam flow increases through the open steam lines, TCVs open in response to rising equalizing header pressure.

Technical References: Lesson plan COR002-09-02 [Digital Electro-Hydraulic Control](Rev 20), procedure 2.2.77.1 [Digital Electro-Hydraulic (DEH) Control System](Rev 42), procedure 2.4MSIV [Inadvertent MSIV Closure](Rev 10)

References to be provided to applicants during exam: none

Learning Objective: COR002-09-02 Obj LO-4d, Describe how the DEH Control system operates to control the following: Pressure setpoint/pressure demand

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(5)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	

PSA Applicability:
N/A

CNS OPERATIONS MANUAL ABNORMAL PROCEDURE 2.4MSIV INADVERTENT MSIV CLOSURE	USE: CONTINUOUS QUALITY: QAPD RELATED EFFECTIVE: 1/18/17 APPROVAL: ITR-RDM OWNER: OSG SUPV DEPARTMENT: OPS

1. ENTRY CONDITIONS

1.1 MSIV indicates closed on Panel 9-3.

1.2 All of following:

1.2.1 Higher than normal steam flow in other main steam lines.

1.2.2 Reactor pressure rises.

1.2.3 Power level rises.

2. AUTOMATIC ACTIONS

2.1 None.

3. IMMEDIATE OPERATOR ACTIONS

3.1 None.

4. SUBSEQUENT ACTIONS

4.1 Record current time and date. Time/Date: ________/__________

NOTE – Steps 4.2 and 4.3 may be performed concurrently.

4.2 Perform Rapid Power Reduction per Procedure 2.1.10 to < 75% RTP.

4.3 Place control switch for affected MSIV(s) to CLOSE.

4.4 IF only one line is isolated or conditions did not result in a scram, THEN maintain MSIV(s) closed until Engineering Evaluation has been performed.Ⓟ[1]

NOTE – MS-MO-78, OUTBD THROTTLE VLV, stroke time is ~ 24 seconds.

4.5 Ensure main steam line drain is in service as follows (PNL 9-4):

4.5.1 Ensure MS-MO-79, RO BYPASS VLV, is closed.

4.5.2 Throttle open MS-MO-78, OUTBD THROTTLE VLV, to intermediate position.

4.5.3 Fully open MS-MO-78, OUTBD THROTTLE VLV.

4.5.4 Open MS-MO-77, OUTBD ISOL VLV.

REACTOR HIGH PRESSURE

PANEL/WINDOW: 9-5-2/F-2

1. AUTOMATIC ACTIONS

   1.1 DEH System operates to control throttle header pressure.

2. OPERATOR OBSERVATION AND ACTION

   2.1 Check reactor pressure by use of other pressure instruments.

   2.2 Check for inadvertent MSIV closure.

   2.3 Enter Procedure 2.4MSIV as dictated by plant conditions.

   2.4 **IF reactor pressure cannot be maintained ≤1030 psig, THEN SCRAM and enter Procedure 2.1.5.**

Scram Actions

Scram Actions

Lesson Number:	COR002-09-02	Revision: 20

3. MODE 3 - TURBINE LOAD CONTROL

LO-04c,15c

At synchronous speed, the turbine generator is synchronized with, and tied to, the grid. As soon as the first generator output breaker is shut, the Mode-3 indicator will be displayed on HMI:

LO-07l

In Mode Three, the load demand is ramped up automatically to 200 MWe.

Operation in Mode 3 will continue as long as the bypass valves are not shut.

4. MODE 4 - TURBINE FOLLOW REACTOR MANUAL

LO-15d

The transfer of the DEH system between Mode 3 and Mode 4 is accomplished by increasing the Load Control signal above the Pressure Control signal.

In Mode 4, a small "close bias" is applied to the BPV summer to ensure that the bypass valves remain closed during small variations in pressure.

LO-04a,e, 08n

The reactor, in Mode 4, is still in manual control and turbine generator load can be increased by manually increasing the reactor power level either with recirculation flow or control rod movement. An increase in steam generation in Mode 4 will cause the pressure to rise and open the governor valves thereby picking up more generator load.

To avoid an inadvertent transfer to Mode 3 while power is being increased in Mode 4, the load setpoint must be maintained higher than the Pressure setpoint.

.

LO-02,08j,k B. DEH Power Supplies

1. The CONTROL TRICON has two redundant power feeds which are:

AC power 120 VAC, EE-PNL-CDP1A breaker 6.
AC power 120 VAC, EE-PNL-NBPP breaker 1.

Lesson Number:	COR002-09-02	Revision: 20

time that the turbine BPVs fully close.

LO-04e,m,15d

d. DEH MODE 4

The TURBINE FOLLOW REACTOR mode is the normal mode DEH is in while the turbine generator is in service. It is entered when the load demand signal (MWe demand) exceeds the throttle pressure demand signal. As was previously mentioned, entry into this mode is typically indicated by bypass valve closure, (although bypass valve closure does not cause this mode change). In the Turbine Follow Reactor mode of operation a turbine load increase is achieved by increasing reactor power which increases throttle pressure which causes the GVs to open further to accept the additional steam flow in order to control pressure. Simply stated, DEH is in a GV pressure control mode. If the LOAD DEMAND becomes limiting, DEH will shift back to LOAD CONTROL, the GVs will modulate at the prescribed load and the BPVs will modulate to control pressure. Normally, however, the LOAD DEMAND setpoint (MWe demand) is adjusted up and out of the way to prevent this from occurring.

II. SYSTEM COMPONENTS

LO-03g,i,j

A The CONTROL TRICON

The Control Tricon consists of one main chassis and one expansion chassis. The main chassis contains: (2) two redundant power supply modules, (3) three main processor modules, (2) two communications modules, and (1) one analog input and (2) analog output modules. The expansion chassis contains: (2) two redundant power supply modules, (3) three digital input and (3) three digital output modules, (1) one relay output module, and (1) one pulse input module.

LO-03g,i,j The DEH Control Tricon System has the following characteristics:

LO-01e a. Three throttle header pressure transmitters for Control Room indication and system control function.

14. TRANSFERRING DEH FROM MODE 3 TO MODE 4

14.1 On LOAD SETPOINT control, verify RAMP RATE displays 10.

14.1.1 If required, set RAMP RATE to 10 as follows:

14.1.1.1 Press RATE to display keypad.

14.1.1.2 Enter 10.

14.1.1.3 Press OK.

14.1.1.4 Verify 10 displays in RAMP RATE display.

14.2 Set ACTUAL SP to 940 MWe as follows:

14.2.1 Press TARGET SP to display keypad.

14.2.2 Enter 940.

14.2.3 Press OK.

14.2.4 Verify 940 displays IN TARGET SP display.

14.2.5 Verify HOLD button backlights yellow.

PROCEDURE 2.2.77.1 REVISION 42 PAGE 8 OF 74

Examination Outline Cross-Reference	Level	RO
295038 (EPE 15) High Offsite Radioactivity Release Rate / 9 Knowledge of the reasons for the following responses as they apply to HIGH OFF-SITE RELEASE RATE: EK3.03 Control room ventilation isolation: Plant-Specific	Tier#	1
	Group#	1
	K/A #	295038 EK3.03
	Rating	3.7
	Revision	0
Revision Statement:		

Question 34

Which one of the following completes the statements below regarding Control Room ventilation isolation during a Fuel Handling Accident (FHA) causing high Off Site release rates?

Control Room ventilation automatically isolates due to ____(1)____ to protect Control Room operators by maintaining the Control Room Envelope (CRE) at a ____(2)____ pressure.

A. (1) Control Room High Radiation
(2) positive

B. (1) Control Room High Radiation
(2) negative

C. (1) Reactor Building Exhaust Plenum High-High Radiation
(2) positive

D. (1) Reactor Building Exhaust Plenum High-High Radiation
(2) negative

Answer: C

Explanation:
Control Room ventilation automatically isolates due to a Group 6 isolation signal to maintain the CRE pressure positive to support Control Room operator habitability. Group 6 isolation occurs if Reactor Building Exhaust Plenum High-High Radiation setpoint (10mr/hr) is reached.
The design basis Fuel Handling accident results in a Group 6 isolation due to Reactor Bldg Vent Exhaust Plenum High Radiation. Upon a Group 6 isolation, CREFS initiates. The following actions occur:

- BF-C-1A, EMER BSTR FAN, starts

- HV-270AV, CONTROL ROOM HVAC INLET VALVE, closes
- HV-271AV, CONTROL ROOM HVAC EMER BYPASS VLV, opens
- EF-C-1B, TOILET EXH FAN, stops
- HV-272AV, CONTROL ROOM PANTRY EXH FAN ISOL SYSTEM, closes

Distracters:
Answer A part 1 choice is plausible due to Control Room Hi Rad requiring entry into procedure 5.1RAD which provides guidance to manually align Control Room ventilation and CR Hi Rad providing isolation signals at other BWRs. The examinee that confuses CR HVAC auto isolation signals and recognizes the CR pressure is maintained positive would choose this answer. It is incorrect due Control Room ventilation isolates due to RB Exh H-Hi Rad. Part 2 is correct.

Answer B part 1 is plausible and wrong for the reason stated for distractor A. Part 2 is plausible because Standby Gas Treatment system also initiates on a Group 6 isolation, and it is designed to maintain the Reactor Building at a negative pressure to mitigate radiation exposure. It is wrong because CREFS maintains the CRE at a positive pressure to mitigate radiation exposure to control room personnel.

Answer D part 1 is correct. Part 2 is plausible and wrong for the reason given for distractor B.

Technical References:
Procedure 2.3_9-3-1 (Panel 9-3 - Annunciator 9-3-1), Rev. 39
Procedure 2.3_9-4-1 (Panel 9-4 - Annunciator 9-4-1), Rev. 59
Procedure 2.1.22 (Recovering from A Group Isolation), Rev. 62
Procedure 2.2.84 (HVAC Main Control Room And Cable Spreading Room), Rev. 59

References to be provided to applicants during exam: NONE

Learning Objective: COR0010802001140A Briefly describe the following concepts as they apply to Control Room HVAC: Airborne contamination (e.g., radiological,toxic gas, smoke) control
COR001-08-01 Obj 10b, Given plant and/or HVAC system conditions, apply the below listed concepts as they are associated with the HVAC system and predict the resultant condition of the system (including components): Differential pressure control

Question Source:	Bank #	12/2015 ILT NRC Q#18
(note changes; attach parent)	Modified Bank #	
	New	
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(5)	

Level of Difficulty:	2
SRO Only Justification:	N/A
PSA Applicability:	
N/A	

9.3.5 Control Room Emergency Filter System (CREFS) starts (VBD-R):

9.3.5.1 BF-C-1A, EMER BSTR FAN, starts.

9.3.5.2 EF-C-1B, TOILET EXH FAN, stops.

9.3.5.3 HV-270AV, CONTROL ROOM HVAC INLET VALVE, closes.

9.3.5.4 HV-271AV, CONTROL ROOM HVAC EMERGENCY BYPASS SYSTEM INLET VALVE, opens.

9.3.5.5 HV-272AV, CONTROL ROOM PANTRY EXHAUST FAN ISOLATION VALVE, closes.

9.3.6 Following REC and SW valves are open (VBD-M):

9.3.6.1 REC-MO-711, NORTH CRITICAL LOOP SUPPLY VLV.

9.3.6.2 SW-MO-650, REC HX A SERVICE WATER OUTLET (intermediate open if valve was closed before isolation occurred).

9.3.6.3 REC-MO-714, SOUTH CRITICAL LOOP SUPPLY VLV.

9.3.6.4 SW-MO-651, REC HX B SERVICE WATER OUTLET (intermediate open if valve was closed before isolation occurred).

9.4 Align SGT per Procedure 2.2.73 within 1 hour of receiving Group 6.8[1]

9.5 Monitor RRMG Set temperatures closely and take action per Procedure 2.4HVAC.

PROCEDURE 2.1.22 REVISION 62 PAGE 17 OF 30

ATTACHMENT 2 INFORMATION SHEET

1. DISCUSSION

1.1 FUNCTION

1.1.1 The system provides HVAC to the Control Room and Cable Spreading Room for personnel comfort and optimum equipment performance.

1.2 OPERATING CHARACTERISTICS

1.2.1 Main Control Room and Cable Spreading Room HVAC is supplied by Air Conditioning Unit AC-C-1A. Air is drawn in through the dampers both from the outside and from the Booster Fan BF-C-1B outlet through the recirculation damper.

1.2.2 Control Room pantry and toilet have a common Exhaust System Fan EF-C-1B and isolation valve. EF-C-1B has a control switch on Board R and a local starter near the Control Room bathroom door. If EF-C-1B is secured from the local starter, the isolation valve will not close and the fan will indicate that it is running on Board R.

1.2.3 Air Conditioning Unit AC-C-1A is comprised of a filter, 3 DX cooling coils, heating coil, and two Supply Fans SF-C-1A and SF-C-1B.

1.2.4 Fire/Smoke Dampers HV-AD-AD1544, HV-AD-AD1545, HV-AD-AD1546, HV-AD-AD1547, HV-AD-AD1581, and HV-AD-AD1582 automatically close when fire or smoke is detected locally at the damper or when smoke is detected in the Cable Spreading Room to prevent smoke from spreading to the Control Room when there is a fire in the Cable Spreading Room.

1.2.5 The Control Room System has an Emergency Bypass System consisting of a Pre-Filter PF-C-1A, High Efficiency Filter HEF-C-1A, Carbon Filter CF-C-1A, and Emergency Booster Fan BF-C-1A which can be supplied from either MCC-LX or MCC-TX via a manual transfer switch in the Auxiliary Relay Room. Upon a Group 6 Isolation signal, this Bypass System is energized and allows outside air to pass through it to the AC unit. During Bypass System operation, one AC unit supply fan is required to run in order to maintain positive Control Room pressure. Additionally, the exhaust booster fan is required to run to provide backpressure which prevents inlet air flow rates from exceeding the Tech Spec limit. This system is designed to maintain the Control Room environment for 200 man-days under the above conditions. Testing has shown that, for maximum radiological protection during a radiological event, one of two system lineups is recommended. The first is the Bypass System lineup with the emergency booster fan, exhaust booster fan, and one supply fan operating. This is the designed emergency operating configuration. The second lineup is a lineup where no fans operate. This configuration is assured during a loss of power only if all fans are aligned to the same divisional power source.

SETPOINT	CIC	9-4-1/E-4
1. (1763) RX BLDG VENT MONITOR A HI-HI RAD at 10 mR/hr	1. RMP-RM-452A	
2. (1764) RX BLDG VENT MONITOR B HI-HI RAD at 10 mR/hr	2. RMP-RM-452B	
3. (1779) RX BLDG VENT MONITOR C HI-HI RAD at 10 mR/hr	3. RMP-RM-452C	
4. (1780) RX BLDG VENT MONITOR D HI-HI RAD at 10 mR/hr	4. RMP-RM-452D	

PROBABLE CAUSES

- Refueling floor accident.
- Line external to primary containment breaks.

REFERENCES

- General Operating Procedure 2.1.22, Recovering From a Group Isolation.
- Emergency Procedure 5.1RAD, Building Radiation Trouble.

PROCEDURE 2.3_9-4-1 REVISION 59 PAGE 46 OF 69

RX BLDG VENT HI-HI RAD	PANEL/WINDOW: 9-4-1/E-4

1. AUTOMATIC ACTIONS
   1.1 Group 6 Isolation.
2. OPERATOR OBSERVATION AND ACTION
   2.1 Notify Radiation Protection.
   2.2 Make gaitronics announcement for all personnel to evacuate Reactor Building.
   2.3 Concurrently enter Procedures 2.1.22 and 5.1RAD.

PROCEDURE 2.3_9-3-1 REVISION 39 PAGE 40 OF 131

CONTROL ROOM HIGH RAD	PANEL/WINDOW: 9-3-1/B-10

1. OPERATOR OBSERVATION AND ACTION
   1.1 IF associated indicator on Panel 9-11 is below alarm setpoint, THEN reset alarm.
   1.2 IF associated indicator on Panel 9-11 remains above alarm setpoint, THEN perform following:
      1.2.1 Clear Control Room of all unnecessary personnel.
      1.2.2 Notify Plant personnel to stay clear of Control Room via gaitronics.
      1.2.3 Notify Radiation Protection to survey area.
      1.2.4 Concurrently enter Procedure 5.1RAD.
   1.3 IF conditions require Control Room evacuation, THEN enter Procedure 5.1ASD.

Lesson Number:	COR001-08-01	Revision: 29

LO-10c, 14b	The emergency bypass supply fan is intended to prevent the introduction of unfiltered air into the Control Room envelope (which includes the cable spreading room) by maintaining the Control Room envelope at a positive pressure as compared to the adjoining buildings and the outside atmosphere under calm wind conditions.
LO-10a, 14a	The PCIS group 6 isolation signal is an indicator of a Loss of Coolant Accident or Fuel Handling accident. Combining the group 6 isolation signal with the rapid stroke times of the isolation valves, ensure dose for Control Room personnel to remain below limits.
LO-06g,10a, 12a SO-7c, 9c, d	Upon PCIS a group 6 isolation, an alarm is annunciated in the Control Room, and the emergency supply fan starts.
LO-14a; 20a,c; 22a	Once the fan starts, the intake valves automatically shift to ensure that all outside air passes through the filter train. Another valve which also repositions is the kitchen/toilet exhaust valve (closes). If the emergency supply fan fails to start, then the dampers will not shift. Also the pantry/toilet exhaust fan is interlocked to trip whenever the emergency supply fan starts.
SO-08 LO-10a,14b, 21	In the event that a Control Room envelope door is blocked open or is otherwise damaged, the Control Room Emergency Filter System must be considered inoperable.
LO-10a,14a	A Continuous Air Monitor (CAM), located in the Control Room, provides indication of control room habitability. Upon high airborne or iodine condition, the CAM unit will locally alarm and cause Annunciator Q-1/A-2 to alarm. The operator will be directed by procedure to place CREFS into service.

2. Air Conditioning Unit (AC-C-1A)

The Control Room AC unit draws in air from the outside and from the discharge of the systems exhaust fan (recirculated air). If it comes from outside, it normally just passes through an isolation damper, but in an emergency (high radiation), the air passes through the emergency bypass filter train prior to entering the AC unit.

Lesson Number:	COR002-28-02 (1487)	Rev. No. 26

I. SYSTEM BRIEF DESCRIPTION

A. System Purpose

LO-01a; 5c
SO-01

1. With the Reactor Building isolated, the STANDBY GAS TREATMENT (SGT) System will reduce and maintain the Reactor Building at a negative pressure of at least 0.25" H_2O.

2. SGT processes atmosphere from the primary and secondary containment when high radiation levels required a system with a higher filtering capability than normal ventilation systems provide to limit the discharge of radionuclides to the environs.

3. SGT performs leak tests on the Secondary Containment to ensure Secondary Containment integrity.

LO-03 B. Design Basis

SO-07a

1. Both SGT System trains start automatically in the event of a Secondary Containment isolation signal (i.e., PCIS Group 6).

LO-10g

2. After both trains have started, one train may be placed in the standby mode. The standby train will restart automatically if the operating unit indicates "low flow".

3. Both trains may be controlled from the Main Control Room.

4. In the event a train is being operated for test purposes, a Secondary Containment isolation signal will automatically select and start the other train. The signal will also provide the proper alignment of dampers in both trains.

5. Manual alignment will provide for decay heat removal from fission products deposited on either filter bank.

6. Gas temperatures, heater temperatures, and overall filter bank pressure differential will be indicated and high values will be annunciated in the Main Control Room.

7. Low flow in the selected train, automatic transfer upon low flow in the selected train, or low flow in the standby train after automatic transfer due to failure of the selected train will be annunciated in the Main Control Room.

Examination Outline Cross-Reference	Level	RO
295017 (APE 17) Abnormal Offsite Release Rate / 9 Knowledge of the interrelations between HIGH OFF-SITE RELEASE RATE and the following: AK2.10 Process radiation monitoring system	Tier#	1
	Group#	2
	K/A #	295017 AK2.10
	Rating	3.3
	Revision	0
Revision Statement:		

Question 35

The plant is at 100% power when a steam leak in the Reactor Building results in a rising offsite release rate through Reactor Building Ventilation system.

(1) What is the LOWEST radiation level sensed at the Reactor Building Ventilation Exhaust Plenum Radiation Monitors at which this release through Reactor Building Ventilation will be automatically isolated?
(Assume ACTUAL setpoints.)

AND

(2) Which one of the following combinations of Reactor Building Vent Exhaust Plenum Radiation Monitors indicating above the isolation setpoint will cause automatic isolation of Reactor Building Vent system?

A. (1) 5 mR/hr
(2) RMP-RM-452B and RMP-RM-452D

B. (1) 5 mR/hr
(2) RMP-RM-452C and RMP-RM-452D

C. (1) 10 mR/hr
(2) RMP-RM-452B and RMP-RM-452D

D. (1) 10 mR/hr
(2) RMP-RM-452C and RMP-RM-452D

Answer: D
Explanation: This is a modified version of 3/2017 ILT NRC Q#28. It was modified by changing the channel combinations in part 2 of all of the answers.

Reactor Building Vent Exhaust Plenum Radiation Monitors RMP-RM-452A,B,C,D initiate a Group 6 isolation, including isolation of Reactor Building Vent, at a setpoint of 10 mR/hr. The logic arrangement for a high-high trip is (A or C) AND (B or D). Therefore, channels C and D high-high will cause a full Group 6 isolation

Distracters:
Answer A part 1 is plausible because it reflects the setpoint of annunciator 9-4-1/E-5 [Rx Bldg Vent High Rad]. It is wrong because the high-high trip setpoint for RMP-RM-452A,B,C,D is 10 mR/hr (≤49 mR/hr TS). Part 2 is plausible because Group 6 logic for RB Vent Exhaust Plenum Rad is one-out-of-two taken twice, so two channels must trip to cause a Group 6 isolation/initiation. It is wrong because the logic arrangement is (A or C) AND (B or D). Therefore, channels B and D high-high will NOT cause a Group 6 isolation, since neither channel A nor C is tripped.

Answer B part is plausible and wrong for the same reason given for distractor A. Part 2 is correct.

Answer C part 1 is correct. Part 2 is plausible and wrong for the same reason given for distractor A.

Technical References: Alarm card 9-4-1/E-4 [Rx Bldg Vent Hi-Hi Rad](Rev 59), alarm card 9-4-1/E-5 [Rx Bldg Vent High Rad](Rev 59), Procedure 2.1.22 [Recovering from a Group Isolation](Rev 62)

References to be provided to applicants during exam:

Learning Objective: COR002-03-02 OPS Containment, Obj LO-2, Given plant conditions, determine if the following should have occurred:
a. Secondary Containment isolation, b. Any of the PCIS group isolations

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	3/2017 ILT NRC Q#28
	New	
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(7)	
Level of Difficulty:	2	
SRO Only Justification:	N/A	
PSA Applicability:		

Top 10 Risk Significant System - PCIS

Examination Outline Cross-Reference	Level	RO
295034 Secondary Containment Ventilation High Radiation / 9 2.4.31 Knowledge of annunciator alarms, indications, or response procedures. (CFR: 41.10)	Tier #	1
	Group #	2
	K/A #	295034 G2.4.31
	Rating	4.2
	Revision	1
Revision Statement: In stem changed "annunciators are" to "annunciator is".		

Question 28

The following annunciators are received while operating at 100% power:

RX BLDG VENT HI-HI RAD	PANEL/WINDOW: 9-4-1/E-4

(1) What is the LOWEST radiation level that caused this alarm?

AND

(2) What combination of Reactor Building Vent Exhaust Plenum Radiation Monitors indicating above Hi-Hi Rad setpoint will result in isolation of Secondary Containment?

A. (1) 5 mR/hr
(2) RMP-RM-452A and RMP-RM-452B

B. (1) 5 mR/hr
(2) RMP-RM-452A and RMP-RM-452C

C. (1) 10 mR/hr
(2) RMP-RM-452A and RMP-RM-452B

D. (1) 10 mR/hr
(2) RMP-RM-452A and RMP-RM-452C

Answer: C. (1) 10 mR/hr (2) RMP-RM-452A and RMP-RM-452B

9-4-1/E-4

SETPOINT	CIC
1. (1763) RX BLDG VENT MONITOR A HI-HI RAD at 10 mR/hr	1. RMP-RM-452A
2. (1764) RX BLDG VENT MONITOR B HI-HI RAD at 10 mR/hr	2. RMP-RM-452B
3. (1779) RX BLDG VENT MONITOR C HI-HI RAD at 10 mR/hr	3. RMP-RM-452C
4. (1780) RX BLDG VENT MONITOR D HI-HI RAD at 10 mR/hr	4. RMP-RM-452D

PROBABLE CAUSES

- Refueling floor accident.
- Line external to primary containment breaks.

REFERENCES

- General Operating Procedure 2.1.22, Recovering From a Group Isolation.
- Emergency Procedure 5.1RAD, Building Radiation Trouble.

RX BLDG VENT HI-HI RAD	PANEL/WINDOW: 9-4-1/E-4

1. AUTOMATIC ACTIONS
   1.1 Group 6 Isolation.
2. OPERATOR OBSERVATION AND ACTION
   2.1 Notify Radiation Protection.
   2.2 Make gaitronics announcement for all personnel to evacuate Reactor Building.
   2.3 Concurrently enter Procedures 2.1.22 and 5.1RAD.

8.9 Check Group 5, CHANNEL A indicating lights turn on (Panel 9-5).

8.10 Check Group 5, CHANNEL B indicating lights turn on (Panel 9-5).

8.11 If RCIC steam lines remain isolated long enough to cool down, they shall be warmed slowly per Procedure 2.2.67 before returning RCIC to operation.

8.12 IF RCIC steam lines are warm, THEN return RCIC to required mode of operation per Procedure 2.2.67.

9. GROUP 6 ISOLATION

9.1 IF manual insertion of Group 6 Isolation required, THEN perform Step 9.1.1 or 9.1.2.

9.1.1 To cause full Group 6 Isolation, perform following:

9.1.1.1 Place Mode switch for RMP-RM-452A, RX BLDG VENT RAD MON CH A, to TRIP TEST.

9.1.1.2 Place Mode switch for RMP-RM-452B, RX BLDG VENT RAD MON CH B, to TRIP TEST.

9.1.1.3 Place Mode switch for RMP-RM-452A to OPERATE.

9.1.1.4 Place Mode switch for RMP-RM-452B to OPERATE.

9.1.2 To cause full Group 6 Isolation, perform following:

9.1.2.1 Place Mode switch for RMP-RM-452C, RX BLDG VENT RAD MON CH C, to TRIP TEST.

9.1.2.2 Place Mode switch for RMP-RM-452D, RX BLDG VENT RAD MON CH D, to TRIP TEST.

9.1.2.3 Place Mode switch for RMP-RM-452C to OPERATE.

9.1.2.4 Place Mode switch for RMP-RM-452D to OPERATE.

9.2 IF Primary Containment inerting was in-progress, THEN perform following:

CAUTION – Rupture disc on N_2 inerting line may have blown causing life-threatening atmosphere at R-903-SW area.

NOTE – Rupture disc PC-RD-NPS opens at 60 psig.

9.2.1 IF full Group 6 Isolation, THEN check N_2 flow on PC-FI-515, N_2 FLOW (VBD-H).

9.2.1.1 IF N_2 flow > 0 cfm, THEN assume rupture disc blown and perform following:

NOTE – Steps 9.2.1.1a through 9.2.1.1c may be performed concurrently.

a. Evacuate Reactor Building by making gaitronics announcement.

b. Inform Shift Manager/Control Room Supervisor of condition.

c. Control access to Reactor Building such that personnel entering building shall wear SCBAs until O_2 concentrations in building have been ensured.

9.2.1.2 At N_2 storage tank, close N2-99, NITROGEN SUPPLY ROOT ISOLATION VALVE.

9.2.1.3 Shut down Primary Containment N_2 Inerting System per Procedure 2.2.60.

9.3 Upon full Group 6 Isolation, ensure following actions have occurred:

9.3.1 Following primary containment purge ventilation isolation valves are closed (VBD-H):

9.3.1.1 PC-AO-246, DW EXH OUTBD ISOL VLV.

9.3.1.2 PC-MO-231, DW EXH INBD ISOL VLV.

9.3.1.3 PC-MO-306, VALVE MO 231 BYPASS VLV, if ISOLATION OVERRIDE control switch on Panel P1 is not in OVERRIDE.

9.3.1.4 PC-MO-232, DW INLET INBD ISOL VLV.

9.3.1.5 PC-AO-238, DW INLET OUTBD ISOL VLV.

9.3.1.6 PC-MO-233, TORUS INLET INBD ISOL VLV, if ISOLATION OVERRIDE switch on Panel P2 is not in OVERRIDE.

9.3.1.7 PC-AO-237, TORUS INLET OUTBD ISOL VLV, if ISOLATION OVERRIDE switch on Panel P2 is not in OVERRIDE.

9.3.1.8 PC-AO-245, TORUS EXH OUTBD ISOL VLV.

9.3.1.9 PC-MO-230, TORUS EXH INBD ISOL VLV.

9.3.1.10 PC-MO-305, VALVE MO 230 BYPASS VLV, if ISOLATION OVERRIDE switch on Panel P2 is not in OVERRIDE.

9.3.2 The Standby Gas Treatment System starts (VBD-K).

9.3.2.1 EF-R-1E, A SGT EXHAUST FAN, starts.

9.3.2.2 SGT-DPCV-546A, SGT A RX BLDG D/P CONTROL, opens to maintain Reactor Building ΔP.

9.3.2.3 EF-R-1F, B SGT EXHAUST FAN, starts.

9.3.2.4 SGT-DPCV-546B, SGT B RX BLDG D/P CONTROL, opens to maintain Reactor Building ΔP.

9.3.2.5 AD-R-1A closes.

9.3.2.6 AD-R-1B opens.

9.3.3 Following Reactor Building HVAC System supply and exhaust fans have tripped, and their isolation valves are closed (VBD-R):

9.3.3.1 SF-R-1A-A, SUPPLY FAN.

9.3.3.2 SF-R-1A-B, SUPPLY FAN.

9.3.3.3 HV-MO-272, HV-R-1A DISCH VLV.

9.3.3.4 HV-AO-257, HV-R-1A DISCH VLV.

9.3.3.5 EF-R-1A, EXHAUST FAN.

9.3.3.6 EF-R-1B, EXHAUST FAN.

9.3.3.7 HV-AO-259, EXH FANS DISCH VLV.

9.3.3.8 HV-AO-261, EXH FANS DISCH VLV.

9.3.3.9 HV-MO-258, EXH FANS DISCH VLV.

9.3.3.10 HV-MO-260, EXH FANS DISCH VLV.

9.3.3.11 BF-R-1A, EXHAUST BOOSTER FAN.

9.3.3.12 BF-R-1B, EXHAUST BOOSTER FAN.

SETPOINT	CIC	9-4-1/E-5
5 mR/hr		
1. (1777) RX BLDG VENT MONITOR DIV I HIGH RAD, Monitor A or C	1. RMP-RR-455 CH-1 or CH-3	
2. (1778) RX BLDG VENT MONITOR DIV II HIGH RAD, Monitor B or D	2. RMP-RR-455 CH-2 or CH-4	

PROBABLE CAUSES

- Refueling activities.

REFERENCES

- Technical Specification LCO 3.3.6.2, Secondary Containment Isolation Instrumentation.
- Off-Site Dose Assessment Manual DLCO 3.2.1, Gaseous Effluents Concentration.
- Off-Site Dose Assessment Manual DLCO 3.2.2, Noble Gases Dose.
- Off-Site Dose Assessment Manual DLCO 3.2.3, Iodine and Particulates.
- Emergency Procedure 5.1RAD, Building Radiation Trouble.

Examination Outline Cross-Reference	Level	RO
295037 (EPE 14) Scram Condition Present and Reactor Power Above APRM Downscale or Unknown / 1 Ability to operate and/or monitor the following as they apply to SCRAM CONDITION PRESENT AND REACTOR POWER ABOVE APRM DOWNSCALE OR UNKNOWN: EA1.07 RMCS: Plant-Specific	Tier#	1
	Group#	1
	K/A #	295037
	Rating	3.9
	Revision	0
Revision Statement:		

Question 36

A hydraulic block ATWS has occurred with approximately two thirds of the control rods failing to fully insert.

- Reactor power is 8%.
- CRD pump 1A is operating.
- Action is being taken to manually insert control rods.

Which mode of control rod operation is used and why?

A. Continuous In mode in order to bypass the Rod Sequence Timer

B. Emergency In mode in order to bypass the Rod Sequence Timer

C. Continuous In mode in order to bypass Rod Worth Minimizer Insert rod blocks

D. Emergency In mode in order to bypass Rod Worth Minimizer Insert rod blocks

Answer: B

Explanation:
EOP-6A is entered from EOP-1A due to failure to scram and power above 3%. EOP-6A step FS/Q-17 directs rod insertion per procedure 5.8.3. Procedure 5.8.3 Att. 1 flowchart step ARI-20 (3) directs the operator to use the Emergency Override switch (on panel 9-5) to insert control rods. This switch is labeled Emergency Notch Override and has three positions: Emer Rod In, Off, and Override. Position Emer Rod In is used for control rod insertion and is commonly referred to as Emergency In mode.

The Emergency Rod In mode is used because it bypasses the Rod Sequence Timer and allows more rapid insertion of the control rods. Bypassing the Rod Sequence Timer eliminates the timed settle function that occurs when a rod motion signal is removed in both the Normal and Continuous In modes of operation and takes several seconds to complete. Selection of another control rod is prevented until the settle function times out. Bypassing this function allows another control rod to be selected and begin inserting immediately.

Distracters:
Answer A is plausible because control switch on panel 9-5 labeled Movement Control Control is used for normal rod movement and, if held in the IN position, will cause the selected control rod to continuously insert to full in. It is wrong because when this switch is released for IN position, the rod sequence timer initiates a settle function that takes a few seconds, which would delay selection and insertion of another control rod. Procedure 5.8.3 Att. 1 requires use of Emergency In mode to bypass the Rod Sequence Timer in order to avert that delay.

Answer C is plausible with respect to use of Continuous In as described for distractor A. It is plausible with respect to bypassing RWM rod blocks because at the given power level, RWM enforces rod pattern constraints by both withdrawal and insertion rod blocks, thus inhibiting control rod insertion for skewed rod patterns expected for a hydraulic block ATWS. This answer is wrong because use of Emergency In only bypasses the Rod Sequence Timer, not the RWM. RWM rod blocks are instead bypassed using the keylocked RWM Bypass switch on panel 9-5.

Answer D is plausible and wrong for reasons stated for distractor C.

Technical References: EOP-6A [Reactor Pressure/Power (Failure-to-Scram)](Rev 19), Procedure 5.8.3 [Alternate Rod Insertion Methods](Rev 17),

References to be provided to applicants during exam: none

Learning Objective: INT008-06-06 EO-12, Given plant conditions and ESP 5.8.3, ALTERNATE ROD INSERTION METHODS, determine which methods would successfully insert control rods.

Question Source:	Bank #	8-2014 ILT NRC Q#17
(note changes; attach parent)	Modified Bank #	
	New	

Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X

10CFR Part 55 Content:	55.41(b)(6),(10)

Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA Applicability:		
N/A		

From 8-2014 ILT NRC exam (five ILT NRC exams ago)

Question: 17

An ATWS has occurred with approximately half of the control rods failing to fully insert. Reactor power is 22%. CRD pump 1A is operating. Action is being taken to manually insert control rods.

Which mode of control rod operation is used and why?

a. Continuous In mode in order to bypass the Rod Sequence Timer.

b. Emergency In mode in order to bypass the Rod Sequence Timer.

c. Continuous In mode in order to bypass Rod Worth Minimizer Insert rod blocks.

d. Emergency In mode in order to bypass Rod Worth Minimizer Insert rod blocks.

Answer:

b. Emergency In mode in order to bypass the Rod Sequence Timer.

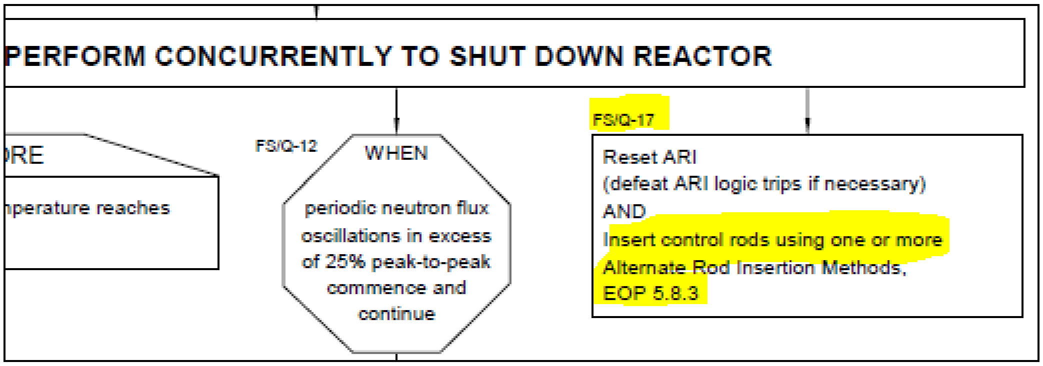
4. ALTERNATE ROD INSERTION

4.1 Perform Attachment 1, Alternate Rod Insertion Methods Flowchart, using the 11" x 17" color-enhanced flowcharts provided in the Control Room.

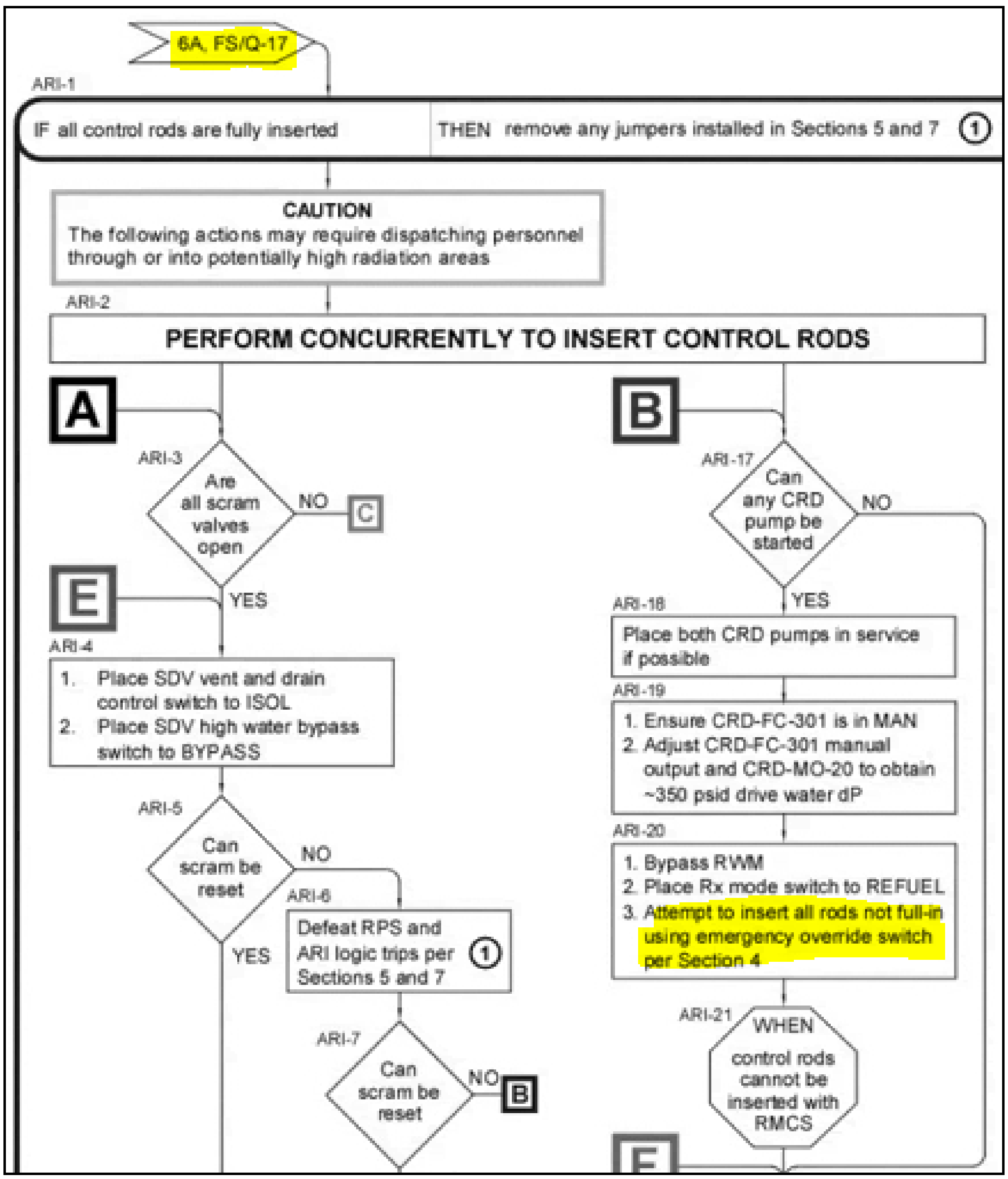
4.2 Under ATWS conditions, control rod insertions should start in the center of the core, or for partial ATWS conditions, the center of the region with lowest control rod density, and proceed to every other control rod in an outward spiral pattern. All control rods should be fully inserted, starting from their post ATWS notch position, in a continuous fashion to the fully inserted position. The following is an example of one possible insertion sequence. Other sequences are permissible as long as the "every-other-rod" pattern shown below is maintained.

	02	06	10	14	18	22	26	30	34	38	42	46	50
51					58		59		60				
47				42		43		44		45			
43			41		26		27		28		29		
39		57		25		14		15		16		46	
35	69		40		13		6		7		30		61
31		56		24		5		2		17		47	
27	68		39		12		1		8		31		62
23		55		23		4		3		18		48	
19	67		38		11		10		9		32		63
15		54		22		21		20		19		49	
11			37		36		35		34		33		
07				53		52		51		50			
03					66		65		64				

From EOP-6A



From procedure 5.8.3, Attachment 1 [Alternate Rod Insertion Methods]



Examination Outline Cross-Reference	**Level**	RO
204000 (SF2 RWCU) Reactor Water Cleanup 2.4.4 Ability to recognize abnormal indications for system operating parameters that are entry-level conditions for emergency and abnormal operating procedures.	**Tier#**	2
	Group#	2
	K/A #	204000 G2.4.4
	Rating	4.5
	Revision	
Revision Statement:		

Question 37

The plant is at 100% power when the following two annunciators are received separately over the course of five minutes due to RWCU Pump A seal failure:

RWCU HI SPACE TEMP	PANEL/WINDOW: 9-4-2/A-5
AREA HIGH TEMP	PANEL/WINDOW: 9-3-1/E-10

(1) Is entry into EOP-5A required for this condition?

AND

(2) Is entry into Procedure 2.1.22 [Recovering from a Group Isolation] required for this condition?

A. (1) No
(2) No

B. (1) No
(2) Yes

C. (1) Yes
(2) No

D. (1) Yes
(2) Yes

Answer: D

Explanation:
There are multiple temperature switches that monitor the RWCU areas to provide high area temperature annunciation in the control room. RWCU-TS-117A monitors RWCU Pump A and B rooms. It inputs into annunciator 9-3-1/E-10 and has a setpoint of 140°F. For RWCU Pump A seal failure, which would cause RWCU pump room temperature to rise, it would be the first temperature switch to alarm. RWCU-TS-117A is listed in EOP-5A Table 9. An EOP-5A entry condition is any area temperature above Maximum Normal Operating temperature, which is indicated by any temperature switch listed in Table 9 alarmed.

Procedure 2.1.22 is the procedure that addresses response to abnormal conditions involving containment isolation signals. PCIS Group 3 involves RWCU isolation valves. One Group 3 isolation signal is RWCU System High Space Temperature. This signal is designed to detect high energy leakage from RWCU as sensed by various temperature switches in associated areas housing RWCU components. RWCU-TS-81A through H and RWCU-TS-150 through RWCU-TS-159A-D monitor various RWCU areas including RWCU pump rooms and input into annunciator 9-4-2/A-5 and Group 3 isolation logic. The setpoint for these switches is 195°F (TS), 185°F (actual). Since a Group 3 isolation is consistent with the subject annunciator, entry into procedure 2.1.22 is required. Alarm Card 9-4-2/A-5 states to enter procedure 2.1.22.

Distracters:
Answer A part 1 is plausible because temperature switches associated with one of the listed alarms, 9-4-2/E-5, are not listed in EOP-5A Table 9 as entry conditions for EOP-5A. An examinee who does know the relationship between RWCU area temperature switches, alarm 9-3-1/E-10, and EOP-5A Table 9 may choose this answer. It is wrong because in addition to RWCU temperature switches associated with alarm 9-4-2/A-5 and Group 3 isolation, different RWCU temperature switches exist that input into alarm 9-3-1/E-10, and those are listed as an EOP-5A entry condition. Part 2 is plausible because one of the listed alarms, 9-3-1/E-10, can be in without a Group 3 isolation, since the setpoints associated with RWCU area temperatures is below the isolation setpoint. For annunciator 9-3-1/E-10, the associated temperature switches related to RWCU have setpoints of 140°F and 150°F, which are below the Group 3 isolation signal setpoint of 195°F. An examinee who does not know alarm 9-4-2/A-5 is consistent with RWCU area temperature above the isolation setpoint and the relationship of the associated temperature instrumentation with Group 3 isolation logic may choose this answer. This answer is wrong because the temperature switches that cause annunciator 9-4-2/A-5 [RWCU High Space Temperature] to alarm also input into Group 3 isolation logic and result in Group 3 isolation at the same setpoint as the annunciator, 195°F (TS).

Answer B part 1 is plausible and wrong for the same reason stated for distractor A. Part 2 is correct.

Answer C part 1 is correct. Part 2 is plausible and wrong for the same reason stated for distractor A.

Technical References: Alarm Cards 9-4-2/A-5 [RWCU High Space Temp](Rev 22), 9-3-1/E-10 [Area High Temp](Rev 39), Procedure 2.1.22 [Recovering from a Group Isolation](Rev 62)		
References to be provided to applicants during exam: none		
Learning Objective: COR001-20-01 Obj LO-9f, Describe the RWCU design features and/or interlocks that provide for the following: System isolation		
Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(7),(10)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA Applicability:		
Top 10 Risk Significant System - PCIS		

SETPOINT	CIC	9-4-2/A-5
185°F (Tech Spec ≤ 195°F)		
1. (1908) RWCU HI SPACE TEMP CHAN A TRIP	1. RWCU-TS-81A through RWCU-TS-81H	
2. (1909) RWCU HI SPACE TEMP CHAN B TRIP	2. RWCU-TS-150 through RWCU-TS-159A-D	

PROBABLE CAUSES

- RWCU line break.

REFERENCES

- Tech Spec Table 3.3.6.1-1, Function 5b.
- General Operating Procedure 2.1.22, Recovering From a Group Isolation.

RWCU
HI SPACE TEMP

PANEL/WINDOW:
9-4-2/A-5

1. AUTOMATIC ACTIONS

   1.1 RWCU-MO-15, INBD ISOL VLV, closes.

   1.2 RWCU-MO-18, OUTBD ISOL VLV, closes.

2. OPERATOR OBSERVATION AND ACTION

   2.1 Throttle RWCU-MO-74, DEMIN SUCTION BYPASS VLV, until pressure indicated on RWCU-PI-131, REGEN HX IND, is equivalent to reactor pressure.

   2.2 Enter Procedure 2.1.22.

6. GROUP 3 ISOLATION

6.1 Upon 1/2 Group 3 Isolation, following occur:

NOTE – If RWCU-MO-15 or RWCU-MO-18 close, operating RWCU pump will trip, causing RWCU F/Ds to go off line and into hold.

6.1.1 If RPS A is lost, following valves close:

6.1.1.1 RWCU-MO-15, INBD ISOL VLV (Panel 9-4).

6.1.1.2 RWCU-MO-18, OUTBD ISOL VLV (Panel 9-4).

6.1.2 If any other 1/2 Group 3 Isolation occurs, RWCU-MO-15 (Div 1) or RWCU-MO-18 (Div 2) will close.

6.1.3 If SLC PUMP A switch is in START, RWCU-MO-15 will isolate and Group 3, CHANNEL A indicating lights will turn off.

6.1.4 If SLC PUMP B switch is in START, RWCU-MO-18 will isolate and Group 3, CHANNEL B indicating lights will turn off.

6.2 Upon full Group 3 Isolation, ensure following valves have closed:

6.2.1 RWCU-MO-15, INBD ISOL VLV (Panel 9-4).

6.2.2 RWCU-MO-18, OUTBD ISOL VLV (Panel 9-4).

PROCEDURE 2.1.22 REVISION 62 PAGE 9 OF 30

6.3 Determine isolation cause:

ISOLATION	ALLOWABLE VALUE	COMMENTS
Low Reactor Water Level	≥ -42"	Ensure Group 6 Isolation.
RWCU System High Flow	≤ 191%	
RWCU System High Space Temperature	≤ 195°F	

SETPOINT	CIC	9-3-1/E-10
1. (1500) RWCU PUMP A ROOM (E 938') AREA TEMP HIGH at 140°F	1. RWCU-TS-117A	
2. (1501) REACTOR SUCTION (W 950') AREA TEMP HIGH at 140°F	2. RWCU-TS-117B	
3. (1502) RWCU PUMP B ROOM (E 938') AREA TEMP HIGH at 140°F	3. RWCU-TS-117A	
4. (1503) RWCU HX ROOM (S 960') AREA TEMP HIGH at 140°F	4. RWCU-TS-117B	
5. (1504) RWCU PHASE SEP ROOM (S 938') AREA TEMP HIGH at 140°F	5. RWCU-TS-117E	
6. (1505) TORUS AREA (SE 896') AREA TEMP HIGH at 140°F	6. RWCU-TS-117F	
7. (1506) TORUS AREA (W 896') AREA TEMP HIGH at 140°F	7. RWCU-TS-117F	
8. (1507) TUNNEL AREA (W 906') AREA TEMP HIGH at 150°F	8. RWCU-TS-117E	
9. (1508) MEZZANINE FLOOR WEST AREA TEMP HIGH at 175°F	9. MS-TS-151A (CH. A)	
10. (1509) RCIC QUAD (SW 859') AREA TEMP HIGH at 175°F	10. RCIC-TS-77A	
11. (1510) RCIC QUAD (N 859') AREA TEMP HIGH at 175°F	11. RCIC-TS-77A	
12. (1511) TORUS AREA (NE 859') AREA TEMP HIGH at 175°F	12. RCIC-TS-77C	
13. (1512) TOP TORUS (ENE) AREA TEMP HIGH at 175°F	13. RCIC-TS-77C	
14. (1513) MEZZANINE FLOOR NORTH AREA TEMP HIGH at 175°F	14. MS-TS-151A (Ch.B)	
15. (1514) TUNNEL MSL A AREA TEMP HIGH at 175°F	15. MS-TS-126A (CH. A)	
16. (1515) TUNNEL MSL B AREA TEMP HIGH at 175°F	16. MS-TS-126A (CH. B)	
17. (1516) TUNNEL MSL C AREA TEMP HIGH at 175°F	17. MS-TS-126C (CH. A)	
(continued)	(continued)	

PROBABLE CAUSES

- Steam leak in affected area.
- Loss of ventilation in area of alarm.
- Feedwater line break in Steam Tunnel.

REFERENCES

- Ⓟ[1] EE 03-086, Revision 0. Affects Step 1.6.
- Tech Spec LCO 3.4.4, RCS Operational LEAKAGE.
- System Operating Procedure 2.2.66, Reactor Water Cleanup.
- Abnormal Procedure 2.4MC-RF, Condensate and Feedwater Abnormal.

From EOP-5A:

SECONDARY CONTAINMENT CONTROL

ANY OF FOLLOWING ENTRY CONDITIONS:

- Area temperature above maximum normal operating value, Secondary Containment Temperatures (TABLE 9)
- Rx Bldg exhaust plenum radiation level above 10 mr/hr
- Area radiation level above maximum normal operating value, Secondary Containment Radiation Levels (TABLE 10)
- Area water level above maximum normal operating value, Secondary Containment Water Levels (TABLE 11)
- Rx Bldg differential pressure at or above 0 in. H_2O
- Access to secondary containment prohibited by elevated temperature, radiation, or water level
- Spent fuel pool temperature above 125°F
- Spent fuel pool level below -4 in. (37 ft. 3 in. or 37.25 ft)

9	SECONDARY CONTAINMENT TEMPERATURES SPDS 16			
Maximum Normal Operating Value Area	Any Temp. Switch Alarmed	Maximum Safe Operating Value Area	Value (°F)	Actual Value
NE Quad	RCIC-TS-77A RCIC-TS-77C	NE Quad	195	
SE Quad	RWCU-TS-117F	SE Quad	195	
NW Quad	RHR-TS-99C	NW Quad	195	
SW Quad and HPCI Room	RHR-TS-99G HPCI-TS-105B HPCI-TS-105D	SW Quad and HPCI Room	195	
1001' El. 976' El. 958' El.	RWCU-TS-117B	1001' El. 976' El. 958' El.	195	
903' El. and 931' El.	RHR-TS-99A RHR-TS-99E MS-TS-126A MS-TS-126C RWCU-TS-117E RWCU-TS-117A HPCI-TS-105A	903' El. and 931' El.	195	

Examination Outline Cross-Reference	Level	RO
295001 (APE 1) Partial or Complete Loss of Forced Core Flow Circulation / 1 & 4 Knowledge of the reasons for the following responses as they apply to PARTIAL OR COMPLETE LOSS OF FORCED CORE FLOW CIRCULATION: AK3.03 Idle loop flow	Tier#	1
	Group#	1
	K/A #	295001 AK3.03
	Rating	2.8
	Revision	0
Revision Statement:		

Question 38

The plant was at 85% power during plant startup when the following annunciator was received:

RECIRC LOOP A OUT OF SERVICE	PANEL/WINDOW: 9-4-3/E-3

Two minutes later, the following stable indications exist:

- JP LOOP FLOW [NBI-FI-92A] 5 Mlbm/hr
- JP LOOP FLOW [NBI-FI-92B] 37 Mlbm/hr
- TOTAL CORE FLOW [NBI-FRDPR-95] 32 Mlbm/hr

(1) What is producing the flow indicated on NBI-FI-92A?

AND

(2) Is flow indicated on TOTAL CORE FLOW [NBI-FRDPR-95] reflective of actual total core flow?

A. (1) RR Pump B driving head
(2) Yes

B. (1) RR Pump B driving head
(2) No

C. (1) Natural circulation driving head
(2) Yes

D. (1) Natural circulation driving head
(2) No

Answer: A

Explanation:
Conditions given represent a trip of RR Pump A at reduced power. It takes ~ 1 minute from time a pump has tripped for indicated core flow to stabilize. Procedure 2.4RR Att. 1 Note 3 states above ~29.5 Mlbm/hr indicated total core flow, driving head from the active RR loop is greater than driving head from natural circulation in the idle RR loop. The flow summer is designed to subtract jet pump flow in the RR loop with the idle pump from the jet pump flow in the RR loop with the running pump. In this case, the flow summer is subtracting 5 mlbm/hr (reverse flow) from 37 mlbm/hr (forward flow) in the operating RR loop, resulting in 32 mlbm/hr total core flow, which is accurate for the given conditions.

When flow is low in the active RR loop, (i.e when Indicated core flow < 24 Mlbm/hr) indicated core flow will read inaccurately on Power-to-Flow map, possibly resulting in indicated core flow indication to the left of the natural circulation line. This is because the driving head from natural circulation in the idle loop overcomes the effect of driving head from the operating RR pump when active loop flow is low. Since indicated total core flow is below 24 Mlbm/hr, the 3 Mlbm/hr indicated for the idle jet pump loop is actually forward flow produced by natural circulation driving head. Procedure 2.4RR states only maintaining core flow > 29.5 Mlbm/hr ensures backflow (reverse flow) through inactive loop.

Procedure 2.4RR Att. 1 Note 1 at step 1.1 states core flow may indicate higher than actual if a RR pump is tripped and reverse core flow summer is not operating; following indicate summer is operating:

- Annunciator 9-4-3/E-3 (9-4-3/E-7), RECIRC LOOP A (B) OUT OF SERVICE, alarming.
- Indicated core flow approximately equal to difference between NBI-FI-92A and NBI-FI-92B, JP LOOP FLOW.

Distracters:
Answer B part 1 is correct. Answer B part 2 is plausible because for low core flow conditions below ~29.5 mlbm/hr, the core flow summer is inaccurate because it always subtracts idle loop jet pump flow from operating loop jet pump flow during single loop operation. Below 29.5 mlbm/hr, jet pump flow in both RR loops would be forward, so the core flow summer would errantly indicate lower than actual core flow. This answer is wrong because flow in idle RR loop A is reversed for the given conditions, and the core flow summer is subtracting RR loop A flow from RR loop B flow, resulting in accurate core flow indication.

Answer C part 1 is plausible because at reduced core flow natural circulation in an idle RR loop can overcome the effects of driving head from the operating RR loop, causing forward flow in the idle loop. This answer is wrong because indicated core flow given in the stem is above 29.5 mlbm/hr, so idle loop flow is reversed because the driving head from RR loop B exceeds the driving head from natural circulation in RR loop A. Part 2 is correct.

Answer D part 1 is plausible and wrong for the same reason given for distractor C. Part 2 is plausible and wrong for the same reason given for distractor B.

Technical References: Procedure 2.4RR [Reactor Recirculation Abnormal](Rev 45)

References to be provided to applicants during exam: none

Learning Objective: COR002-22-02 Obj. LO-4u, Describe the interrelationships between the Reactor Recirculation system or the Recirculation Flow Control system and the following: Core flow; 5h, Describe the following concepts as they apply to the Reactor Recirculation system, or to the Recirculation Flow Control system: Natural circulation

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(5)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA Applicability:		
N/A		

ATTACHMENT 1 TRIP OF REACTOR RECIRCULATION PUMP(S)

ATTACHMENT 1 TRIP OF REACTOR RECIRCULATION PUMP(S)

1. IF one RR pump trips, THEN perform following:

NOTE 1 – Core flow may indicate higher than actual if a RR pump is tripped and reverse core flow summer is not operating; following indicate summer is operating:

- Annunciator 9-4-3/E-3 (9-4-3/E-7), RECIRC LOOP A (B) OUT OF SERVICE, alarming.
- Indicated core flow approximately equal to difference between NBI-FI-92A and NBI-FI-92B, JP LOOP FLOW.

NOTE 2 – Indicated core flow < $24x10^6$ lbs/hr will cause idle loop flow to reverse direction and rise which will cause indicated core flow to read inaccurately on Power-to-Flow map.

NOTE 3 – Maintaining core flow > 29.5×10^6 lbs/hr ensures backflow through inactive loop. Operation with core flow < 29.5×10^6 lbs/hr should be minimized while placing an idle RR loop in service. Ⓟ[7]

NOTE 4 – It takes ~ 1 minute from time pump has tripped for indicated core flow to stabilize.

1.1 IF operation in Stability Exclusion Region, THEN concurrently enter Attachment 3 (Page 8).

1.2 For tripped RR pump, ensure RRMG Set A(B) GEN FIELD BKR open.

1.2.1 IF GEN FIELD BKR did not open, THEN perform Step 5 concurrently with remaining steps. Ⓟ[5]

1.3 For tripped RR pump, close RR-MO-53A(B), PUMP DISCHARGE VLV.

1.4 Continue with remaining steps in this attachment while waiting to open RR-MO-53A(B).

1.5 AFTER RR-MO-53A(B) has been closed for 5 minutes, THEN open valve.

1.6 Ensure operating RRMG transferred to Startup Transformer, if available, per Procedure 2.2.18.1.

1.7 Throttle REC-49(51), MG SET A(B) OIL HX OUTLET (R-931-NW), to maintain oil outlet temperature 90°F to 130°F on RRLO-TI-2626A(B), MG SET HX A(B) OUTLET TEMPERATURE (R-931-NW NEAR HXs), for tripped RRMG.

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pumps connected to the affected piping, causing a reduction in core flow.

Failure of the jet pump riser internal to the vessel will prevent operation of the two jet pumps supplied from that riser. This will cause a reduction in core flow due to reverse flow in the idled jet pumps.

3. Failure of One Recirculation Pump

LO-06g

a. If one Recirc pump were to fail or trip, flow through half the jet pumps would coast down and then reverse through the idle jet pump diffusers. The ten operating jet pumps would operate at a higher flow ratio. Calculations show that the operating jet pumps would provide nearly 150% of their normal rated flow.

b. The total flow provided by the jet pumps would be about 75% of rated with about 22% of this flow bypassing the core through the idle jet pumps. The resulting net effect would be a core flow of approximately 53% of rated (slightly higher if operating in the ICF region prior to recirc pump trip) with a corresponding decrease in reactor power.

c. Due to the reduction in flow caused by the trip or malfunction of the Recirc pump a point may be reached on the power to flow map where the Stability Exclusion Region would be entered and entry into 2.4RR Attachment 4, Operation in or near the Stability Exclusion (Instability) Region would be required.

4. Single Loop Operation (2.2.68.1)

LO-04n

Single Recirc loop operation is allowed with the following additional restrictions:

a. Operation in the Stability Exclusion Region is prohibited.

b. LCO 3.4.1 must be satisfied.

c. TLCO 3.2.1 must be satisfied.

LO-08h

Following a trip of one Recirc pump from two loop operation, the discharge valve for the tripped pump should be closed for five minutes. This allows the tripped pump to come to rest. Unless loop isolation is required, the discharge valve is re-opened to allow backflow to keep the idle loop warm. If possible, maintain core flow > 29.5×10^6 lbs/hr to insure backflow.

If core flow indicates to the left of the natural circulation line on the power to flow map, add the jet pump flow indicator (NBI-FI-92A & B) indications together, and enter this as a substitute value for PMIS point B012.

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j. ICF- Increased Core Flow Region
Operation in this region will allow maintaining core thermal power after reaching end-of-cycle (all rods out) coastdown by slowly increasing core flow up to □105% of rated.

Figures 33 and 34 2. Total Core Flow Indication

Core Flow is indicated on NBI-FRDPR-95 (two pen recorder; total core flow and core plate d/p), which is located on the vertical section of Panel 9-5 in the Main Control Room. These indications provide no alarms, no interlock functions and no protective features. They are provided to enhance operator knowledge of reactor core conditions and to enhance core diagnostics, all in the interest of safe reactor operation.

Each of the twenty jet pumps is provided with a differential pressure detector (sensing pressure above the mixer/diffuser sections of each jet pump and comparing these pressures to the pressure below the core plate, which is sensed via the SLC pipe-within-a-pipe below core plate tap), which produces a d/p signal proportional to the total flow ("drive" plus "driven") through the jet pump. When the flow signal for each jet pump is developed (by means of square root extraction – see the Nuclear Boiler Instrumentation lesson for details), all twenty flow signals can be summed to derive the Total Core Flow signal.

Total core flow is derived by adding together the flows through all ten jet pumps in one RR loop with the flows through all ten jet pumps in the other RR loop. As seen in Figure 33, a total of four 5-input summers receive the derived jet pump flow outputs as their inputs.

a. Jet pumps 1-5 input to 5 Input Summer 2-3-75B
b. Jet pumps 6-10 input to 5 Input Summer 2-3-75D
c. Jet pumps 11-15 input to 5 Input Summer 2-3-75A
d. Jet pumps 16-20 input to 5 Input Summer 2-3-75C

The outputs of the 5 input summers are provided as the inputs to proportional amplifiers:

a. 5 Input Summers 2-3-75B and 2-3-75D input to Proportional Amplifier 2-3-76B ("B" RR Loop Total Jet Pump Flow)
b. 5 Input Summers 2-3-75A and 2-3-75C input to Proportional Amplifier 2-3-76A ("A" RR Loop Total Jet Pump Flow)

The outputs of the two proportional amplifiers (2-3-76B and A) are provided as inputs to Proportional Amplifier 2-3-96, which is the "Two RR Pumps Running" proportional amplifier. Its output will be indicated on NBI-FRDPR-95 when BOTH RR pumps are running. (The specific signals it must "see" are identified in the paragraphs to follow in this same section.)

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a. If both RR pumps are running, the outputs of 2-3-76B and 2-3-76A are added (summed) together in Proportional Amplifier 2-3-96 to produce a total core flow signal which is indicated on NBI-FRDPR-95

b. Proportional Amplifier 2-3-96 also provides as outputs the two Jet Pump Loop Flow "A" and "B" signals, which are indicated on Panel 9-4 instruments, NBI-FI-92A and B.

If one RR loop is idle, the two jet pump loop flow signals are provided as inputs to the "One RR Pump Running" Proportional Amplifier 2-3-97. The total jet pump flow signal produced from the summation of the jet pump flows in the idle loop are subtracted from the total jet pump flow signal produced by the active loop.

a. This is necessary, because the d/p cells used to produce jet pump flow signals cannot determine if the differential pressure being sensed is being produced by forward flow (i.e., active loop) through the jet pumps in its associated RR loop or by reverse flow (i.e., idle loop).

b. It is vitally important that control room operators understand that whenever there is an idle RR loop, some of the flow coming from the active loop will bypass the core and flow in the reverse direction through the idle jet pumps. The operators must be able to determine that core flow is being accurately determined by the Jet Pump Flow Summing network.

   1) The quick and simple check to determine JP Flow Summing network accuracy is to subtract the flow in the idle loop (as read on NBI-FI-92A or B) from the flow in the active loop. The difference between the two indications is total core flow, which can be used to determine if indicated Total Core Flow (NBI-FRDPR-95) is accurate or faulty and if indicated core flow on the Power to Flow Map (PMIS) is accurate of faulty.

The method used by the Jet Pump Flow Summing network to determine if the RR loops are active or idle is explained by means of the Recirculation Loop Out-Of-Service Determination, which is shown in Figure 34.

The contacts associated with RR Pump "A" ("B") running (or not) originates in the associated pump's field breaker circuit.

The contacts associated with RR-MO-53A (53B) open (or not) originates in the associated valve's Limitorque motor operator auxiliary switch contacts.

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a. If both RR pumps are in operation:

Relay 2D-K1A	De-energized
Relay 2D-K2A	De-energized
Relay 2D-K3A	De-energized
Relay 2D-K1B	De-energized
Relay 2D-K2B	De-energized
Relay 2D-K3B	De-energized

By means of the contacts associated with these relays, the outputs of both jet pump loop flow proportional amplifiers (2-3-76B and 2-3-76A) are summed to derive the Total Core Flow signal.

b. If A RR pump is running; B RR pump idle:

Relay 2D-K1A	Energized
Relay 2D-K2A	Energized
Relay 2D-K3A	Energized
Relay 2D-K1B	De-energized
Relay 2D-K2B	De-energized
Relay 2D-K3B	De-energized

By means of the contacts associated with these relays, the "B" Jet Pump Loop Flow signal is subtracted from the "A" Jet Pump Loop Flow signal.

c. If B RR pump is running; A RR pump idle:

Relay 2D-K1A	De-energized
Relay 2D-K2A	De-energized
Relay 2D-K3A	De-energized
Relay 2D-K1B	Energized
Relay 2D-K2B	Energized
Relay 2D-K3B	Energized

By means of the contacts associated with these relays, the "A" Jet Pump Loop Flow signal is subtracted from the "B" Jet Pump Loop Flow signal.

d. If RR Loop "A" is out of service, relay 2D-K1B is energized, which provides input to annunciator 9-4-3/E-3, RECIRC LOOP "A" OUT OF SERVICE.

e. If RR Loop "B" is out of service, relay 2D-K1A is energized, which provides input to annunciator 9-4-3/E-7, RECIRC LOOP "B" OUT OF SERVICE.

Examination Outline Cross-Reference	Level	RO
700000 (APE 25) Generator Voltage and Electric Grid Disturbances / 6 Knowledge of the interrelations between GENERATOR VOLTAGE AND ELECTRIC GRID DISTURBANCES and the following: AK2.02 Breakers, relays	Tier#	1
	Group#	1
	K/A #	700000 AK2.02
	Rating	3.1
	Revision	0
Revision Statement:		

Question 39

The plant is operating at rated power.

ALL off-site power voltages simultaneously lower causing ALL 4160 VAC bus voltages to stabilize at 3800 VAC.

Which one of the following completes the statements below regarding the status of Diesel Generators (DGs) and 480 VAC Load Shedding if Grid voltage remains at this value for 2 minutes?

Both DG(s) ____(1)____ be running.

480 VAC Load-Shedding ____(2)____ occur.

A. (1) will
(2) will

B. (1) will
(2) will NOT

C. (1) will NOT
(2) will

D. (1) will NOT
(2) will NOT

Answer: A
Explanation: With the NSST supplying 1A/1F & 1B/1G and bus voltage lowering to 3800 volts, breakers 1FA and 1GB will trip 12.5 seconds after voltage has lowered below 3880

VAC. The "loss of voltage" signal will start the Diesel generators and apply a close permissive to 1FS & 1GS. As the Emergency Transformer voltage is also degraded, 1FS/1GS will not automatically close and the EDGs will close onto the bus when they have reached rated voltage and speed (at least 10 seconds after the bus was de-energized). As the "loss of voltage" signal exists for > 5.5 seconds, 480 volt load-shedding will be initiated and 12 breakers will receive a trip signal.

Distracters:

B. This answer is incorrect due to 480 VAC load shed occurs. This choice is plausible if the time from reaching the first level undervoltage were reduced to less than 5.5 seconds. The examinee that correctly identifies the degraded voltage starting both DGs and confuses first & second level undervoltage logic would select this answer.

C. This answer is incorrect due to both DGs automatically starting. This choice is plausible if the undervoltage setpoints and time delays are not known or confused. The examinee that confuses degraded voltage DG starts and remember 480 VAC load shed logic would select this answer.

D. This answer is incorrect due to both DGs automatically starting and 480 VAC load shed occurring. This choice is plausible if the undervoltage setpoints and time delays are not known or confused and the time from reaching the first level undervoltage were reduced to less than 5.5 seconds. The examinee that confuses degraded voltage DG starts and first & second level undervoltage logic would select this answer.

Technical References: Procedure 2.2.18.1 [4160V Auxiliary Power Distribution System](Rev 2), procedure 5.3GRID [Degraded Grid Voltage](Rev 53)

References to be provided to applicants during exam: none

Learning Objective: COR0010102001080B Predict the consequences of the following on plant operation: 4160V Critical bus undervoltage

Question Source:	Bank #	12-2015 ILT NRC Q#45
(note changes; attach parent)	Modified Bank #	
	New	
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(7)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	

PSA Applicability:
Top 10 Risk Significant Systems – Emergency AC Power, DGs

From 12-2015 ILT NRC exam

Question 45

The plant is operating at rated power.

ALL off-site power voltages simultaneously lower causing ALL 4160 VAC bus voltages to stabilize at 3800 VAC.

Which one of the following completes the statements below regarding the status of Diesel Generators (DGs) and 480 VAC Load Shedding if Grid voltage remains at this value for 2 minutes?

____(1)____ DGs will be running.

480 VAC Load Shedding ____(2)____ occur.

A. (1) Both
(2) will

B. (1) Both
(2) will NOT

C. (1) Neither
(2) will

D. (1) Neither
(2) will NOT

Answer:
A. (1) Both (2) will

2. INTERLOCKS AND SETPOINTS

2.1 SECOND LEVEL UNDERVOLTAGE (3880V ± 52V WITH 7.5 ± 0.8 SECOND TIME DELAY) ON BUS 1F (1G)

2.1.1 When second level undervoltage is sensed on the supply line from Bus 1A (1B) to Bus 1F (1G) by Relay 27/1FA2 (27/1GB2) for ~ 7.5 seconds, Relay 27/1FA2 (27/1GB2) drops out and causes Relay 27X/1FA2 (27X/1GB2) to pick up.

2.1.2 When second level undervoltage is sensed on Bus 1F (1G) by Relay 27/1F2 (27/1G2) for ~ 7.5 seconds, Relay 27/1F2 (27/1G2) drops out and causes Relay 27X/1F2 (27X/1G2) to pick up.

2.1.3 When Relay 27X/1F2 (27X/1G2) picks up, it causes Relay 27X17/1F (27X17/1G) to pick up.

2.1.4 When Relay 27X17/1F (27X17/1G) picks up, following actions occur:

2.1.4.1 Annunciator C-1/A-7 (C-4/A-2), 4160V BUS 1F (1G) LOW VOLTAGE, alarms.

2.1.4.2 Time Delay Relay 27X15/1F (27X15/1G) (7.5 seconds) starts timing out.

a. When Relay 27X15/1F (27X15/1G) times out, it applies a trip signal to Breaker 1FS (1GS).

2.1.5 When Relays 27X/1F2 (27X/1G2) and 27X/1FA2 (27X/1GB2) are picked up, following actions occur:

2.1.5.1 Time Delay Relay 27X7/1F (27X7/1G) (5 ± 0.5 seconds) starts timing out.

2.1.5.2 Relay 27X10/1F (27X10/1G) picks up.

2.1.6 Relay 27X11/1F (27X11/1G) picks up if a RHR A (B) initiation signal is present or sealed-in as indicated by Relay 10A-K9A (10A-K9B) being picked up.

2.1.7 When Relay 27X7/1F (27X7/1G) has timed out or immediately if Relays 27X10/1F (27X10/1G) and 27X11/1F (27X11/1G) are picked up, Relay 27X12/1F (27X12/1G) picks up.

2.1.8 When Relay 27X12/1F (27X12/1G) picks up, it applies a trip signal to Breaker 1FA (1GB).

2.2 LOSS OF VOLTAGE (2300V) ON BUS 1A (1B)

2.2.1 When a loss of voltage condition is sensed on Bus 1A (1B) by Relay 27/1A (27/1B) for ~ 5 seconds, Relay 27/1A (27/1B) drops out and causes Relay 27X/1A (27X/1B) to pick up.

2.2.2 When Relay 27X/1A (27X/1B) picks up, following actions occur:

2.2.2.1 Annunciator C-2/A-1 (C-3/A-7), 4160V BUS 1A (1B) UNDERVOLTAGE, alarms.

2.2.2.2 Relay 27X1/1A (27X1/1B) drops out.

2.2.2.3 Time Delay Relay 27X2/1A (27X2/1B) (0.5 seconds) starts timing out.

a. Relay 27X2/1A (27X2/1B) will also start timing out if Breakers 1AN (1BN) and 1AS (1BS) are open.

2.2.2.4 A close permissive signal is applied to the remote manual closing logic of Breaker 1AN (1BN).

2.2.2.5 A close permissive signal is applied to the remote manual closing logic of Breaker 1AS (1BS).

2.2.3 When Relay 27X1/1A (27X1/1B) drops out, following actions occur:

NOTE – Condensate and condensate booster pump breakers do not trip on undervoltage.

2.2.3.1 A trip signal is applied to CIRC WATER PUMPS A and B (C and D) breakers.

2.2.3.2 A close permissive signal is applied to the remote manual closing logic of Breaker 1AF (1BG).

2.2.4 When Time Delay Relay 27X2/1A (27X2/1B) times out, Relay 27X4/1A (27X4/1B) drops out.

NOTE – Relays 27X/1F (27X/1G) and 27XX/1F (27XX/1G) have redundant contacts in the following circuits. Either relay picking up will cause the action to occur.

2.4.2 When Relay 27X/1F (27X/1G) and/or 27XX/1F (27XX/1G) picks up, following actions occur:

2.4.2.1 Annunciator C-1/A-6 (C-4/A-1), 4160V BUS 1F (1G) UNDERVOLTAGE, alarms.

2.4.2.2 A start signal is applied to DG1 (DG2) automatic starting logic.

2.4.2.3 Relays 27X1/1F (27X1/1G), 27X2/1F (27X2/1G), and 27X5/1F (27X5/1G) drop out.

2.4.2.4 Time Delay Relay 27X3/1F (27X3/1G) (8 seconds) starts timing out and when relay times out, it sends a close signal to the automatic closing logic of Breaker EG-1 (EG-2).

2.4.3 When Relay 27X1/1F (27X1/1G) drops out, following actions occur:

2.4.3.1 A loss of voltage condition on Bus 1F (1G) signal is sent to the CS and RHR A (B) initiation logics, as indicated by Relays 14A-K3A (14A-K3B) and 10A-K3A (10A-K3B) dropping out or remaining dropped out.

2.4.3.2 A trip signal is applied to following breakers:

a. SW Pumps A and C (B and D).

b. SWB Pumps A and C (B and D).

2.4.4 When Relay 27X2/1F (27X2/1G) drops out, following actions occur:

2.4.4.1 A loss of voltage condition on Bus 1F (1G) signal is sent to the CS and RHR A (B) initiation logics, as indicated by Relays 14A-K4A (14A-K4B) and 10A-K4A (10A-K4B) dropping out or remaining dropped out.

2.4.4.2 A trip signal is applied to the following breakers:

a. CS Pump A (B).

b. RHR Pumps A and B (C and D).

2.4.4.3 Time Delay Relay 27X18/1F (27X18/1G) (5.5 seconds) starts timing out and when relay times out, it causes Relay 27X19/1F (27X19/1G) to pick up. When Relay 27X19/1F (27X19/1G) picks up, it sends a trip signal to following breakers if they are closed:

a. CRD Pump A (B).

b. SAC 1A (1B).

c. MCC-OG1 (MCC-MR).

d. MCC-M (MCC-U).

e. MCC-N (MCC-V).

f. MCC-P (MCC-W).

2.4.5 When Relay 27X5/1F (27X5/1G) drops out, following actions occur:

2.4.5.1 A close permissive signal is applied to the remote and local manual closing logic of Breaker EG-1 (EG-2).

2.4.5.2 A close permissive signal is applied to the remote manual closing logic of Breaker 1FA (1GB).

2.4.5.3 A close permissive signal is applied to the remote manual closing logic and a close signal is applied to the automatic closing logic of Breaker 1FS (1GS).

1.14 If DCC System Operator receives a CNS 69 kV bus low voltage alarm, DCC System Operator will notify CNS Control Room and take action to raise 69 kV voltage.

1.15 DCC System Operator receives a CNS 161 kV bus alarm if at low alarm setpoint. If alarm comes in, DCC System Operator will notify CNS Control Room.

1.16 DCC System Operator will notify CNS Control Room when any of following conditions no longer exist:

1.16.1 CNS 69 kV bus low voltage alarm.

1.16.2 CNS 161 kV bus low voltage alarm.

1.16.3 Any CNS Contingency Analysis violation.©2

1.16.4 Congestion that had potential to affect CNS generation or off-site power supplies.

1.17 Transfer of 4160V critical buses is performed at a readable voltage (3950V) that is slightly above the Technical Specification upper allowable value for the secondary level undervoltage relays (3932V).

1.18 Isolating non-critical 4160V buses at 3600V is based on 4 kV motors that are rated at +/- 10%. The non-critical buses have overcurrent bus breaker protection, but do not have automatic undervoltage protection. Below 3600V equipment damage is probable; therefore, it's prudent to manually isolate the buses if the voltage degrades to this value. Risk Assessment has reviewed this configuration and concurs with the action.

1.19 Actions in this procedure to place the voltage regulator to OFF are mandated under conditions indicative of a CNS voltage regulator oscillation causing 345 kV voltage variations. If the grid voltage is oscillating and voltage regulator is working as designed, as grid voltage lowers regulator will raise field amps in an attempt to maintain terminal voltage. If regulator is causing the oscillations, field amps rising will cause 345 kV volts to rise. So, if 345 kV voltage rises as field amps lower, regulator is working properly and there is no need to transfer to the base adjuster. If 345 kV voltage rises as our field amps rise, then our regulator is driving the voltage oscillations and transferring to the base adjuster should stabilize conditions.

1.20 There are two levels of undervoltage protection at CNS. The first level is a loss of voltage protection which is designed to actuate at conditions indicative of voltage rapidly collapsing to zero volts. The relays which actuate are a time undervoltage relay with inverse time characteristics (i.e., the lower the voltage, the faster the actuation). The timer starts timing at bus voltage < 2870V. The second level of undervoltage protection is for sustained low voltage conditions. This system is designed to respond to a static low voltage condition and will actuate whenever the bus voltage drops below 3880V ± 52V for a time delay of 7.5 ± 0.8 seconds.

1.21 Expected plant response to loss of all off-site power (simultaneous loss of 345 kV, 161 kV, and 69 kV lines):

If all off-site power sources are lost simultaneously, the main generator will trip, causing loss of NSST. If there is no bus lockout, 1AS and 1BS will close on to the SSST when 1AN and 1BN trip open. 1AS and 1BS will close even if there is no voltage on the SSST secondary. 1AF, 1FA, 1BG, and 1GB will trip in < 1 second (with an inverse time constant, "0" volts will result in a very short delay before the breakers trip on first level protection). The DGs will receive an auto start signal at the same time as these breakers receive a trip signal. The voltage permissive for 1FS and 1GS will not be met, so these breakers will not close. When DGs reach rated voltage and speed, and at least 10 seconds after the first level voltage protection signal was sensed, DG output breakers will close and energize 4160 VAC Bus 1F/1G. The only 4160 VAC loads that trip on undervoltage are the RRMG Sets and circ water pumps (setpoints similar to the first level undervoltage protection). The condensate booster pumps will trip on low suction pressure or low oil pressure. All 4160 VAC loads powered from 1F/1G will trip, except the 480V transformer feed. In addition, once the first level protection signal has been sensed for at least 5.5 seconds, load shedding of selected 480 VAC loads will occur. The breakers require manual operator action to restore to service.

CRD Pumps A and B, Air Compressors A and B, MCCs OG1, P, N, and M (480 Switchgear 1F), and MCCs MR, U, W, and V (480 Switchgear 1G) are the breakers that receive a trip from the load shedding relays. If reactor power is > 30%, the reactor will scram immediately when the loss of off-site power occurs.

1.22 Expected plant response to all off-site power degraded with DGs available:

If all off-site power sources degrade simultaneously at a similar rate, the first alarm will be the 1FS/1GS auto closure prohibited annunciator, and these breakers will not automatically close. As voltage lowers below 3880, a 7.5 second timer starts (no alarm). When this times out, C-1/A-7(C-4/A-2), 4160V BUS 1F (1G) LOW VOLTAGE, alarms. If a LPCI initiation signal is present, Breaker 1FA/1GB will trip immediately. If no LPCI initiation, these breakers will trip 5 seconds later. This results in Bus 1F/1G de-energizing and starting the first level undervoltage protection scheme as described in the preceding paragraph. When RPS frequency or voltage drops too low, EPAs trip and the RPS buses will de-energize. When RPS is lost, reactor scrams and group isolations occur. The RRMG Sets will not reach their trip voltage, but will trip due to loss of lube oil after a 6 second pressure switch delay. 4160 VAC BOP loads will not trip, but continue to run on degraded voltage. 1AS and 1BS will close on to the SSST when Breakers 1AN and 1BN trip open. These breakers will close even if there is low voltage on the SSST secondary. Load-shedding of the 480V breakers occur as described in preceding paragraph.

Examination Outline Cross-Reference	Level	RO
295012 (APE 12) High Drywell Temperature / 5 Ability to determine and/or interpret the following as they apply to HIGH DRYWELL TEMPERATURE: AA2.03 Drywell humidity: Plant-Specific	Tier#	1
	Group#	2
	K/A #	295012 AA2.03
	Rating	2.8
	Revision	0
Revision Statement:		

Question 40

Reference Provided

The plant is at 100% power.

Procedure 2.4PC [Primary Containment Control] has been entered due to changes in the following drywell parameters over the last 2 hours:

- Drywell pressure has risen 0.3 psig
- Inlet/Outlet Temp Unit B, PC-TR-500B (inlet) has risen from 118°F to 126°F
- Inlet Moisture Unit B, PC-MR-500B has risen from 94°F to 96°F

Which one of the following describes the effect of this condition on drywell relative humidity and what would have caused these indications?

DW relative humidity has …

A. risen due to a steam leak.

B. risen due to a DW FCU tube leak.

C. lowered due to a DW FCU shaft shear.

D. lowered due to drywell nitrogen supply PCV-513 leak-by.

Answer: C
Explanation: Procedure 2.4PC Attachment 1 is used to determine DW relative humidity by plotting DW FCU inlet wet bulb temperature PC-MR-500 (A-D) versus DW FCU inlet dry bulb temperature PC-TR-500 (A-D). For the conditions given, plotting the initial values of wet bulb and dry bulb temperature yield a relative humidity of ~50%. Plotting the final values yields ~40% relative humidity. Therefore, relative humidity has lowered. This

is expected because DW atmosphere water vapor content will not change significantly, and if the water vapor content stays the same and the temperature rises, the relative humidity decreases. This is because warmer air requires more moisture to become saturated than does colder air. Of the answers given, the only failure that would cause DW temperature to rise, reflected by the inlet to DW FCU B inlet temperature rising, and relative humidity to lower is loss of heat removal by another DW FCU due to shaft shear.

Shaft cracking on DW FCUs was documented in 2018 by CR-CNS-2018-02868 and 03180.

Distracters:
Answer A is plausible because DW pressure and temperature have risen. The examinee who misreads 2.4PC Att. 1 graph and believes relative humidity increased because the final operating point is higher than the initial operating point on the graph will choose this answer. It is wrong because 2.4PC states a short-term rise in DW relative humidity would accompany a rise in DW pressure and temperature if due to a steam leak; however, DW relative humidity has lowered.

Answer B is plausible for the examinee who misreads 2.4PC Att. 1 graph, as discussed for distractor A, and because the answer reflects water leakage into the DW, which would eventually raise DW atmosphere moisture content. Also, a tube leak could result in decreased effectiveness of the affected DW FCU, which would result in elevated DW temperature and pressure. It is wrong because DW relative humidity has actually lowered.

Answer D is plausible because leak-by of DW nitrogen supply PCV-510 would cause DW pressure to rise and relative humidity to lower. It is wrong because it would have negligible effect on DW temperature and not cause DW temperature to rise significantly.

Technical References: CR-CNS-2018-02868, CR-CNS-2018-03180, Procedure 2.4PC [Primary Containment Control](Rev 21)

References to be provided to applicants during exam: 2.4PC [Primary Containment Control] Attachment 1 [Primary Containment Relative Humidity](rev 20)

Learning Objective: INT032-01-28 EO-J, Given plant condition(s) and the applicable Abnormal/Emergency Procedure, discuss the correct subsequent actions required to mitigate the event(s).

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X

Question Cognitive Level:	Memory/Fundamental	

	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(4),(5)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA Applicability:		
N/A		

CNS OPERATIONS MANUAL ABNORMAL PROCEDURE 2.4PC PRIMARY CONTAINMENT CONTROL	USE: CONTINUOUS QUALITY: QAPD RELATED EFFECTIVE: 12/18/19 APPROVAL: ITR-RDM OWNER: AOM-SUPPORT DEPARTMENT: OPS

Scram Actions

1. ENTRY CONDITIONS
   1.1 PC pressure rising.
   1.2 PC temperature rising.
   1.3 PC radiation level rising.
   1.4 DW FCU(s) trip.
   1.5 DW sump pumps operating more than usual.
2. AUTOMATIC ACTIONS
   2.1 None.
3. IMMEDIATE OPERATOR ACTIONS
   3.1 None.
4. SUBSEQUENT ACTIONS
   4.1 Record current time and date. Time/Date: _______/_________
   4.2 **IF while performing this procedure, drywell pressure <u>cannot</u> be maintained ≤1.5 psig, THEN SCRAM and enter Procedure 2.1.5.**

<u>CAUTION</u> – If RB HVAC Isolation signals have been over ridden per Procedure 5.8.20 (EOP PTM 53, 54, 55, and 56), then containment venting per Procedure 2.2.60 is <u>not</u> allowed.

<u>NOTE</u> – Steps 4.3 through 4.8 may be performed concurrently.

Scram Actions

   4.3 Maintain drywell pressure below 0.75 psig by venting containment through SGT System per Procedure 2.2.60.
   4.4 IF drywell pressure <u>cannot</u> be maintained less than or equal to 0.75 psig, THEN enter Conditions and Required Actions of LCO 3.6.1.4.
   4.5 IF drywell pressure <u>cannot</u> be restored <u>and</u> maintained below 0.75 psig, THEN perform rapid power reduction per Procedure 2.1.10.
   4.6 Ensure all available drywell FCU control switches in RUN.

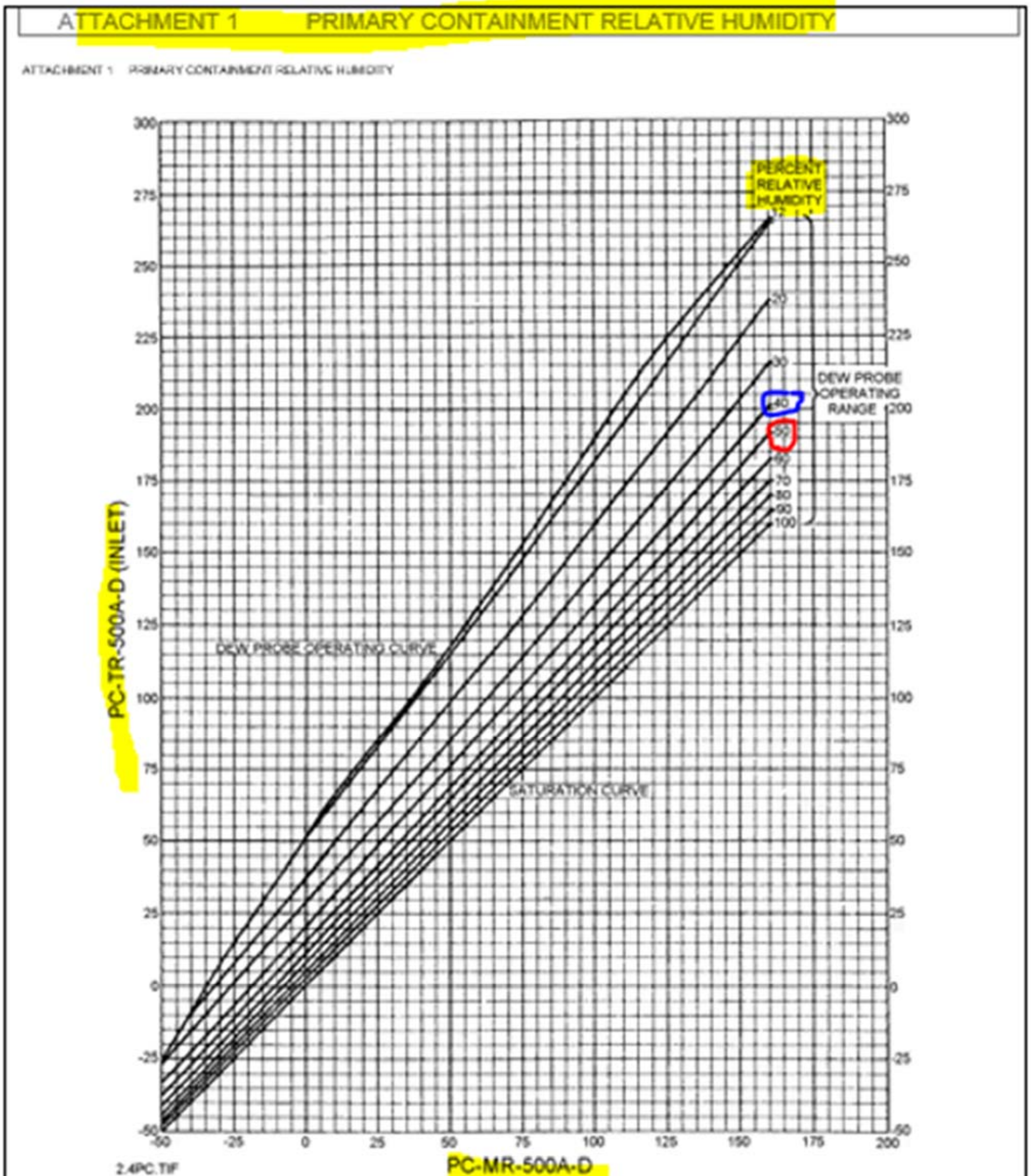
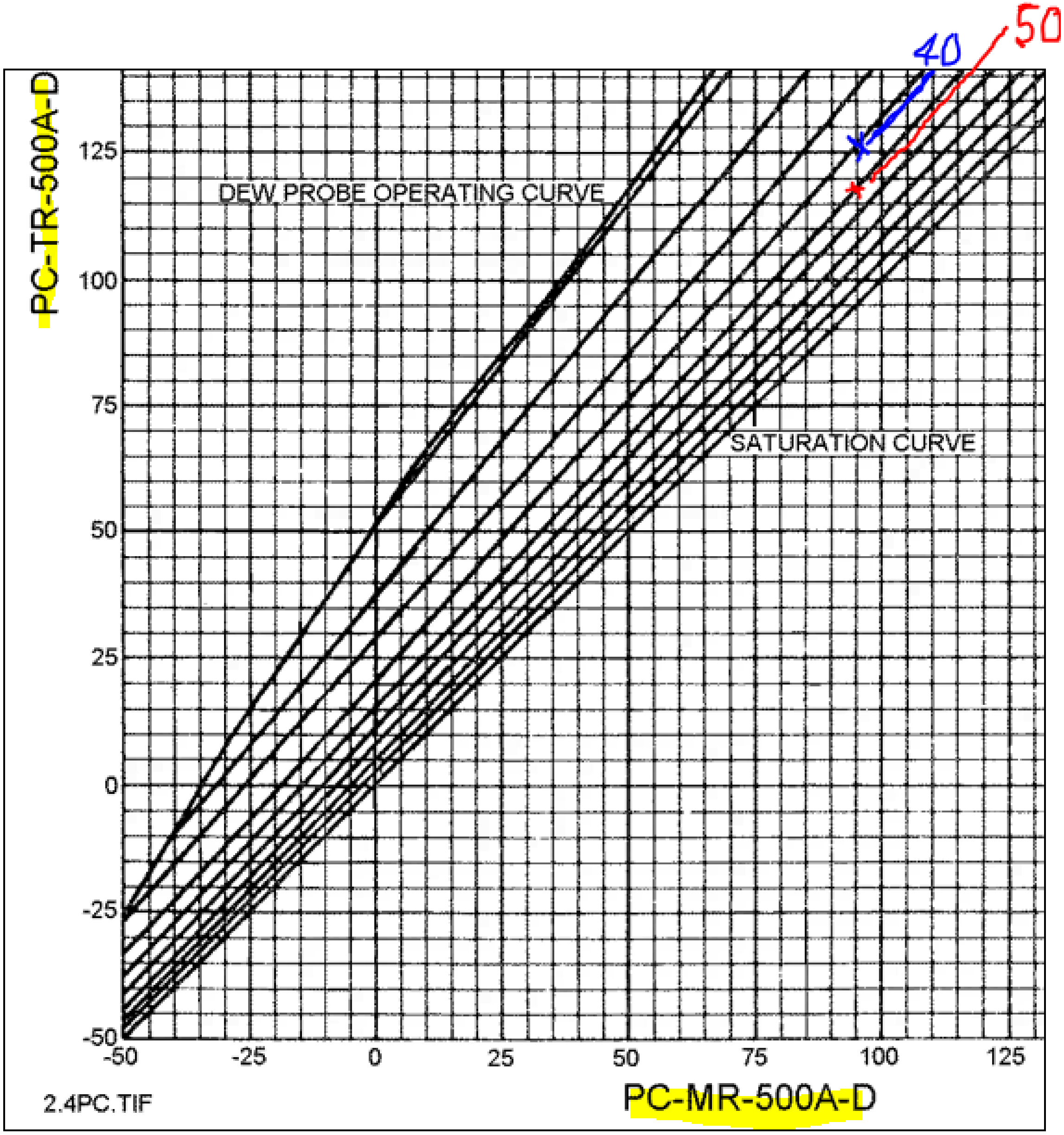

ATTACHMENT 1 PRIMARY CONTAINMENT RELATIVE HUMIDITY
ATTACHMENT 1 PRIMARY CONTAINMENT RELATIVE HUMIDITY
PERCENT RELATIVE HUMIDITY
20
30
40
50
60
70
80
90
100
DEW PROBE OPERATING RANGE
DEW PROBE OPERATING CURVE
SATURATION CURVE
PC-TR-500A-D (INLET)
PC-MR-500A-D
2.4PC.TIF

Figure 1



40
50
125
100
75
50
25
0
-25
-50
DEW PROBE OPERATING CURVE
SATURATION CURVE
-50
-25
0
25
50
75
100
125
PC-TR-500A-D
PC-MR-500A-D
2.4PC.TIF

ATTACHMENT 2 INFORMATION SHEET

ATTACHMENT 2 INFORMATION SHEET

1. DISCUSSION

1.1 The major concern of high drywell temperatures is the effect elevated temperatures can have on RPV water level indications. Primary Containment structure design temperature is 281°F, but EQ equipment in the drywell is qualified for the most limiting postulated DBA which includes peak temperatures of 340°F. Environmental excursions beyond the postulated DBA profile may result in failure of safety-related equipment.

1.2 A total loss of drywell coolers, during power operation, will cause bulk drywell air temperature to initially rise rapidly. Reactor scram on high drywell pressure will occur in several minutes.

1.3 The scram action: *"If drywell pressure cannot be maintained ≤ 1.5 psig"* is based on actual trip setpoints, setpoint tolerances, and to allow a reasonable pressure range for recovery. Per Operations policy, it is preferable to initiate a Manual Scram rather than allow an Automatic Scram to occur.

1.4 Various indications may be used to identify or verify potential leakage from the RCS into the drywell. They include drywell sump flow indications, drywell temperature indications, drywell radiation indications, and drywell relative humidity determination. The trend in drywell relative humidity level is not the most direct indication of steam leakage into the drywell but may be used to verify other indications of potential steam leakage into the drywell. The drywell humidity may be determined by plotting drybulb (PC-TR-500A, PC-TR-500B, PC-TR-500C, PC-TR-500D) and wetbulb (PC-R-MR-500A, PC-R-MR-500B, PC-R-MR-500C, PC-R-MR-500D) temperatures on Attachment 1. A significant, short-term, increasing trend in relative humidity will most likely accompany the initiation of a steam leak in the drywell.

1.5 The two major sources of heat input to the drywell are radiant heat losses from the vessel and piping, and heat generated by the Reactor Recirculation pump motors. The heat generated by the RR pump motors is variable and is directly related to the power being consumed by the motor. Lowering reactor power with control rods does little to lower radiant heat input from the vessel and piping. Lowering RR pump speed to a core flow of 40×10^6 lbs/hr will lower the total heat input to the drywell by nearly two thirds of its value at 70×10^6 lbs/hr.

1.6 The drywell pressure of 0.75 psig is based on the Design Basis Accident (DBA) analysis and Technical Specification 3.6.1.4. The DBA assumes an initial drywell pressure of 0.75 psig. This limitation ensures the safety analysis remains valid by maintaining the expected initial conditions and ensures the peak LOCA drywell internal pressure does not exceed the maximum allowable of 62 psig.

Condition Reports			
Identifier	**Current Workflow Task**	**Due Date - CR**	**Date Created**
CR-CNS-2018-02868	[Closed]		05/11/2018
Initiator	**Initiator's Organization**		
Gage, Joshua J.	Ops Mgmt CNS		
Date of Event	**Time of Event**	**Operability Review Required**	**Reportability Review Required**
05/11/2018	18:58	Yes	Yes
Title (40 characters)			
Control room entered 2.4PC			
Condition Description			
Entered 2.4PC at 1858 due to change in Drywell parameters. The change in DW parameters were noted while taking BOP rounds and during WCO 1900 panel walkdown. AT ~1815 DW pressure took a step change from 0.34 to 0.36 psig as read by PMIS point G039, DW pressure is currently 0.38 psig and stable. DW moisture as read on PC-MR-500A, B, and C rose a couple degrees. PC-MR-500D rose up a couple degrees and then down to a value slightly lower. DW FCU outlet temps as read on PC-TR-500A-D, no change seen on 500A, 500B - 500D all up slightly (~2-3F). DW FCU inlet temp as read on PC-TR-500A-D, 500A, B, C all up 5 - 10F, 500D temp from 130F - 75F. All DW FCU control switches are currently in RUN and indicate running. DW Particulate as read on RMV-RR-4 rose from ~200cpm to 1460cpm. Particulate sample was taken from Chemistry. Method of Discovery: performance of operator rounds and panel walkdown Requirement not met: DW parameter step change			
Immediate Action Description			
updated Control room personnel, entered 2.4 PC			

Condition Reports			
Identifier	**Current Workflow Task**	**Due Date - CR**	**Date Created**
CR-CNS-2018-03180	[Closed]		05/26/2018
Initiator	**Initiator's Organization**		
Palmer, Maurice C.	Ops Mgmt CNS		
Date of Event	**Time of Event**	**Operability Review Required**	**Reportability Review Required**
05/26/2018	16:33	Yes	Yes
Title (40 characters)			
UNPLANNED 2.4PC ENTRY			
Condition Description			
Description: Received ANN -ANN -(H-1/B-2), DRYWELL ZONE 2C HIGH TEMP, Drywell FCU A Temperatures approached each other. Noted change in relative moisture, Recirc Pump Area Temps, and rise in DW particulate. Indications are that Drywell FCU A has failed. Due to changes in Drywell parameters 2.4PC was entered. Requirement Not Met: Abnormal procedure entry (2.4PC) due to probable failed FCU.			
Immediate Action Description			
Informed CRS, entered abnormal procedure.			
Suggested Action Description			
Validate failure and correct.			
Contact Type	**Contact**	**Phone**	
Applicable Supervisor	Ommert, Timothy J.		
Identified By	Palmer, Maurice C.	4028255453	

Examination Outline Cross-Reference	Level	RO
295028 (EPE 5) High Drywell Temperature (Mark I and Mark II only) / 5 Knowledge of the interrelations between HIGH DRYWELL TEMPERATURE and the following: EK2.04 Drywell ventilation	Tier#	1
	Group#	1
	K/A #	295028 EK2.04
	Rating	3.6
	Revision	0
Revision Statement:		

Question 41

The plant is at 100% power when the following annunciator is received:

DRYWELL FCU A HI DISCH TEMP	PANEL/WINDOW: H-1/A-1

Drywell temperature is 130°F, rising slowly.

Drywell pressure is 0.5 psig, rising slowly

(1) EOP-3A entry will be required as soon as average drywell temperature exceeds ________ °F.

AND

(2) Which action is required NOW with respect to DW FCUs?

A. (1) 135°F
(2) Ensure all DW FCU control switches in RUN

B. (1) 135°F
(2) Place all DW FCU control switches in OVERRIDE

C. (1) 150°F
(2) Ensure all DW FCU control switches in RUN

D. (1) 150°F
(2) Place all DW FCU control switches in OVERRIDE

Answer: C

Explanation:
The stem reflects a condition where a problem with one DW FCU is causing DW temperature to rise. EOP-3A entry is required when primary containment temperature exceeds 150°F.

An entry condition for Procedure 2.4PC [Primary Containment Control] is DW temperature rising, so 2.4PC entry is required. 2.4PC step 4.6 requires placing all available DW FCUs in RUN.

Distracters:
Answer A part 1 is plausible because the DW ventilation system is designed to maintain average DW temperature below 135°F. It is wrong because EOP-3A entry is required only when DW average temperature exceeds 150°F. Part 2 is correct.

Answer B part 1 is plausible and wrong for the same reason stated for distractor A. Part 2 is plausible because if DW pressure was above 1.84 psig, DW FCUs would automatically trip and EOP-3A entry would be required due to high DW pressure. EOP-3A step DW/T-3 would require placing DW FCU switches in OVERRIDE to defeat the high DW pressure trip interlock and return DW FCUs to operation. It is wrong because EOP-3A has not yet been entered, so placing DW FCU switches to OVERRIDE is not allowed.

Answer D part 1 is correct. Part 2 is plausible and wrong for the same reason stated for distractor B.

Technical References: EOP-3A [Primary Containment Control](Rev 18), Procedure 2.4PC [Primary Containment Control](Rev 20), PSTG [AMP-TBD00 EOP Technical Basis](Rev 10), lesson plan COR001-08-01 [Ops HVAC](Rev 30)

References to be provided to applicants during exam:

Learning Objective: COR001-08-01 Obj LO-11c, Describe the HVAC design features and interlocks that provide for the following: Automatic starting and stopping of fans;

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(10)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	

PSA Applicability:
N/A

From EOP-3A

PRIMARY CONTAINMENT CONTROL

ANY OF FOLLOWING ENTRY CONDITIONS:

- drywell pressure above 1.84 psig
- PC H_2 concentration above 1%
- average drywell temperature above 150°F
- torus water level above +2 in.
- torus water level below -2 in.
- average torus water temperature above 95°F

Lesson Number:	COR001-08-01	Revision: 31

The airlock HVAC system utilizes its heater unit fans to circulate the air in leakage and maintain railway airlock temperature.

4. Change Area HVAC System

The change area HVAC system maintains its designated area temperatures by adjusting dampers to control inlet and recirculation air mixture.

SO-02b
LO-01e

5. Drywell Heating and Ventilation System

The drywell is cooled by four fan coil units which recirculate the contained gas volume. The system is designed to limit the average air temperature in the drywell to l35ΞF during normal operation.

CNS OPERATIONS MANUAL ABNORMAL PROCEDURE 2.4PC PRIMARY CONTAINMENT CONTROL	USE: CONTINUOUS QUALITY: QAPD RELATED EFFECTIVE: 12/18/19 APPROVAL: ITR-RDM OWNER: AOM-SUPPORT DEPARTMENT: OPS

Scram Actions

1. ENTRY CONDITIONS
   - 1.1 PC pressure rising.
   - 1.2 PC temperature rising.
   - 1.3 PC radiation level rising.
   - 1.4 DW FCU(s) trip.
   - 1.5 DW sump pumps operating more than usual.
2. AUTOMATIC ACTIONS
   - 2.1 None.
3. IMMEDIATE OPERATOR ACTIONS
   - 3.1 None.
4. SUBSEQUENT ACTIONS
   - 4.1 Record current time and date. Time/Date: ______ / ______
   - 4.2 **IF while performing this procedure, drywell pressure cannot be maintained ≤ 1.5 psig, THEN SCRAM and enter Procedure 2.1.5.**

CAUTION – If RB HVAC Isolation signals have been over ridden per Procedure 5.8.20 (EOP PTM 53, 54, 55, and 56), then containment venting per Procedure 2.2.60 is not allowed.

NOTE – Steps 4.3 through 4.8 may be performed concurrently.

Scram Actions

- 4.3 Maintain drywell pressure below 0.75 psig by venting containment through SGT System per Procedure 2.2.60.
- 4.4 IF drywell pressure cannot be maintained less than or equal to 0.75 psig, THEN enter Conditions and Required Actions of LCO 3.6.1.4.
- 4.5 IF drywell pressure cannot be restored and maintained below 0.75 psig, THEN perform rapid power reduction per Procedure 2.1.10.
- 4.6 Ensure all available drywell FCU control switches in RUN.

Lesson Number:	COR001-08-01	Revision: 31

3. Control Room Instrumentation

Instrument/Location	Sensing Point/Type	Description
a. Drywell fan inlet and outlet temperature, Panel H	TR-500 A thru D	1 per cooling unit 50 - 170°F
b. Drywell return air average humidity , Panel H	MR-500 A thru D	1 per cooling unit 0 - 100%

LO-10d
LO-11c
SO-09c

4. Alarms

Tile/Location	Initiating Device/ Setpoint	Additional Functions
a. DRYWELL FCU A(B,C,D) HI DISCH TEMP/ Panel H, H-1/A-1(B-1,C-1,D-1)	TR-500A, B, C, D/ 105°F	None

5. Interlocks and Trips

LO-11a,b,c,d; 12a.b
LO-22d; SO-07h; SO-09a,b,c,d

Interlock/Trip	Initiating Device/ Setpoint	Additional Functions
a. Drywell Fan Coil Units	Drywell high ≤+1.84 psig Reactor low-low-low level ≥ - 113"	Fan coil units trip.
b. Drywell Fan Coil Units	150°F	Auto start on high area temperature near CRD hydraulic piping if in standby.

Lesson Number:	COR001-08-01	Revision: 31

SO-11a,b 6. Control Room Controls

Item/Location	Switch Positions	Functions
a. Primary Containment Purge & Vent Isolation Valves AD-R-1A(1B); Panel R	NORMAL-HAND	AD-R-1A, NORMAL - open, shuts on high radiation. HAND - shut. AD-R-1B, NORMAL - open, shuts on high radiation. HAND - shut.
b. Drywell Fan Coil Units FC-R-1A(1B, 1C, 1D); Panel H	OFF-STDBY-RUN-OVERRIDE	STDBY-FCU auto starts on high area temp. OVERRIDE-allows restart of FCU with LOCA signal present.

Fig 7
LO-01c
SO-02c

F. Turbine Building Heating and Ventilation System

The Turbine Building ventilation system consists of three separate H & V units which supply air to different areas of the Turbine Building, two recirculation fans for moving air around the turbine front standard area, one exhaust hood fan and four exhaust fans which take suction from a common exhaust plenum.

1. Turbine Building H & V Units (HV-T-1A, 1B, 1C)

LO-09c

SO-04c, 6

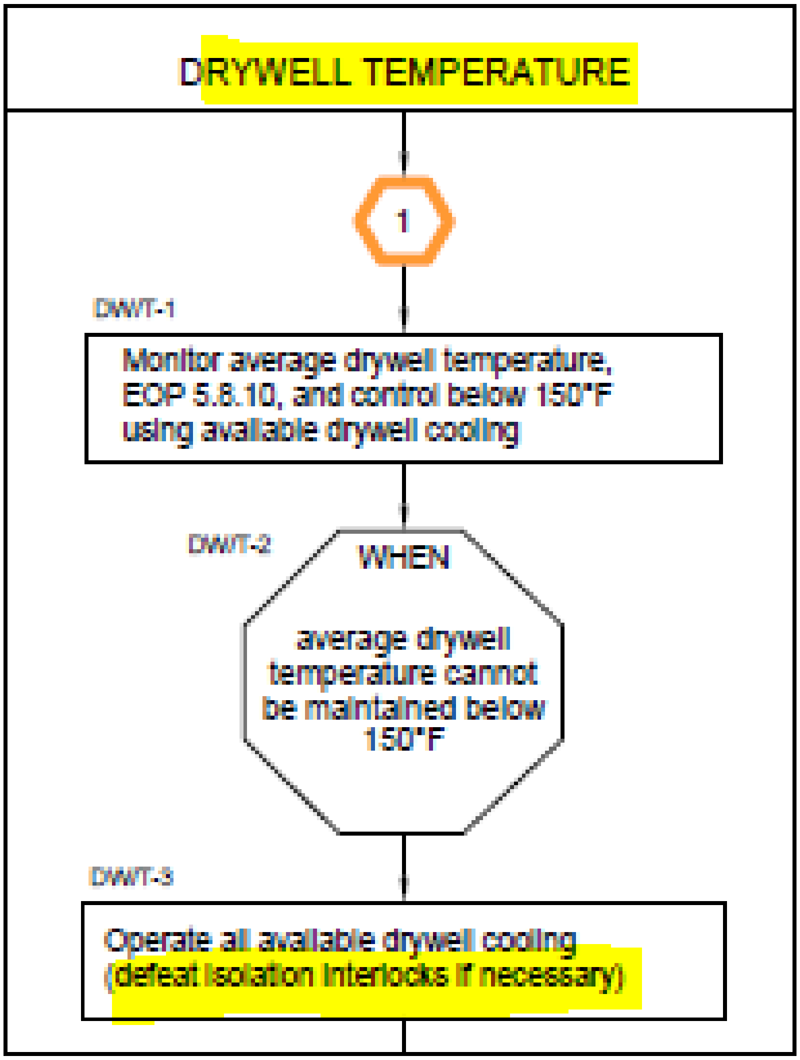
Each unit is essentially the same except for the output capacity and the location served. The components in each unit are: isolation dampers, suction filter, heating coil, supply fans, ΔP controllers, and temperature controllers which control the steam supply valves to maintain temperature. The component operation and physical arrangement relative to each other is the same as discussed under the Reactor Building ventilation section. The supply fan dampers are also normally operated in the MANUAL mode.

One unit supplies the south end of the Turbine Building and the other two units supply the north end, shielded areas, vacuum pump room, SJAE room, and RFP room.

2. Exhaust Hood (SR-1A)

One sample rack fume exhaust hood is associated with the Turbine Building H & V System. It is located in the basement Equipment

From EOP-3A:


DRYWELL TEMPERATURE
1
DWT-1
Monitor average drywell temperature, EOP 5.8.10, and control below 150°F using available drywell cooling
DWT-2
WHEN
average drywell temperature cannot be maintained below 150°F
DWT-3
Operate all available drywell cooling (defeat isolation interlocks if necessary)

EPG/SAG Step

DW/T-1 Operate all available drywell cooling, defeating isolation interlocks if necessary.

PSTG/SATG Step

DW/T-1 Operate all available drywell cooling, defeating isolation interlocks if necessary.

Differences

1. The method of defeating drywell cooling isolation interlocks is to place drywell FCU control switches in OVERRIDE (BR 3035 sh 4).

CNS OPERATIONS MANUAL ABNORMAL PROCEDURE 2.4PC PRIMARY CONTAINMENT CONTROL	USE: CONTINUOUS QUALITY: QAPD RELATED EFFECTIVE: 5/23/18 APPROVAL: ITR-RDM OWNER: AOM-SUPPORT DEPARTMENT: OPS

P&L 2

Scram Actions

1. ENTRY CONDITIONS

1.1 PC pressure rising.

1.2 PC temperature rising.

1.3 PC radiation level rising.

1.4 DW FCU(s) trip.

1.5 DW sump pumps operating more than usual.

2. AUTOMATIC ACTIONS

2.1 None.

3. IMMEDIATE OPERATOR ACTIONS

3.1 None.

4. SUBSEQUENT ACTIONS

4.1 Record current time and date. Time/Date: ________ / ________

4.2 **IF while performing this procedure, drywell pressure <u>cannot</u> be maintained ≤ 1.5 psig, THEN SCRAM and enter Procedure 2.1.5.**

CAUTION – If RB HVAC Isolation signals have been over ridden per Procedure 5.8.20 (EOP PTM 53, 54, 55, and 56), then containment venting per Procedure 2.2.60 is <u>not</u> allowed.

<u>NOTE</u> – Steps 4.3 through 4.8 may be performed concurrently.

Scram Actions

4.3 Maintain drywell pressure below 0.75 psig by venting containment through SGT System per Procedure 2.2.60.

4.4 IF drywell pressure <u>cannot</u> be maintained below 0.75 psig, THEN enter Conditions and Required Actions of LCO 3.6.1.4.

4.5 IF drywell pressure <u>cannot</u> be restored <u>and</u> maintained below 0.75 psig, THEN perform rapid power reduction per Procedure 2.1.10.

4.6 Ensure all available drywell FCU control switches in RUN.

Examination Outline Cross-Reference	Level	RO
295023 (APE 23) Refueling Accidents / 8 Ability to determine and/or interpret the following as they apply to REFUELING ACCIDENTS: AA2.01 Area radiation levels	Tier#	1
	Group#	1
	K/A #	295023 AA2.01
	Rating	3.6
	Revision	0
Revision Statement:		

Question 42

Core offload is in progress during Mode 5 when a fuel bundle drops into the Spent Fuel Pool due a fuel grapple malfunction, resulting in damage to the fuel bundle.

The following annunciator is received due to Fuel Pool Area RMA-RA-1 and Fuel Pool Area RMA-RA-2 in alarm:

REFUEL AREA HIGH RAD	PANEL/WINDOW: 9-3-1/A-10

Which of the following lists EVERY procedure REQUIRED to be entered for this condition?

A. 5.1RAD [Building Radiation Trouble], ONLY

B. 5.1RAD [Building Radiation Trouble] AND EOP-5A, ONLY

C. 5.1RAD [Building Radiation Trouble] AND 5.2FUEL [Fuel Failure], ONLY

D. 5.1RAD [Building Radiation Trouble] AND 5.2FUEL [Fuel Failure] AND EOP-5A

Answer: D

Explanation:
This question requires determining which area radiation monitors are in alarm and interpreting the alarm level in order to identify which procedures are required to be entered. Area radiation monitors RMA-RA-1 and RMA-RA-2 monitor the fuel pool area in the reactor building and input into the subject alarm. Alarm Card 9-3-1/A-10 directs entry into procedure 5.1RAD. An entry condition to procedure 5.1RAD is high or unusual readings on any ARM or ARM recorder; therefore, 5.1RAD entry is required. Alarm Card 9-3-1/A-10 does not direct entry into procedure 5.2FUEL; however, an entry condition to 5.2FUEL is Irradiated fuel damage with release of radioactivity to secondary containment as indicated by HIGH alarm on refueling floor

ARM #2, CAM, or Reactor Building ventilation monitor. Therefore, 5.2FUEL entry is required. An entry condition to EOP-5A is any area radiation level above Maximum Normal Operating value of Table 10. Table 10 lists various area radiation monitors, including RMA-RA-1 and RMA-RA-2, Fuel Pool Area (high and low range). Therefore, EOP-5A entry is required.

Distracters:
Answer A is plausible with respect to absence 5.2FUEL because Alarm Card 9-3-1/A-10 does not direct entry into procedure 5.2FUEL, and 5.2FUEL mainly addresses fuel failure during plant operation. It is plausible with respect to absence of EOP-5A because the majority of areas associated with EOP-5A table 10 are inputs to annunciator 9-3-1/A-9 [Reactor Bldg High Rad], not 9-3-1/A-10. Operators are more familiar with EOP-5A entry due to receipt of 9-3-1/A-9 from simulator training involving steam leaks. An examinee who does not know the area radiation monitors that inputs to 9-3-1/A-10 are also EOP-5A entry conditions will chose this answer. This answer is wrong because an entry condition to 5.2FUEL is Irradiated fuel damage with release of radioactivity to secondary containment as indicated by HIGH alarm on refueling floor ARM #2, so 5.2FUEL entry is required. It also is wrong because RMA-RA-1 or RMA-RA-2, which input to annunciator 9-3-1/A-10, are listed in EOP-5A Table 10, and conditions given represent a secondary containment area above MNO value, so EOP-5A entry is required.

Answer B is plausible and wrong for the same reasons given for distractor A with respect to 5.2FUEL.

Answer C is plausible and wrong for the same reasons given for distractor A with respect to EOP-5A.

Technical References: Alarm card 9-3-1/A-10 [Refuel Area High Rad](Rev 39), Procedure 5.1RAD [Building Radiation Trouble](Rev18), Procedure 5.2FUEL [Fuel Failure](Rev 22), EOP-5A [Secondary Containment Control and Radioactivity Release Control](Rev 19)

References to be provided to applicants during exam: none

Learning Objective: COR001-18-01 Obj LO-11d, Predict the consequences of the following items on the Radiation Monitoring system: Refuel floor handling accidents/operations

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X

Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	

10CFR Part 55 Content:	55.41(b)(10)
Level of Difficulty:	3
SRO Only Justification:	N/A
PSA Applicability:	
N/A	

SETPOINT	CIC	9-3-1/A-10
1. (1448) RX BLDG FUEL POOL (HR) AREA RAD HIGH at 500 mR/Hr	1. RMA-RA-1	
2. (1449) RX BLDG FUEL POOL (LR) AREA RAD HIGH at 10 mR/Hr	2. RMA-RA-2	

PROBABLE CAUSES

- Refueling accident (i.e., dropped fuel bundle).
- Inadvertent removal of radioactive material from shielding.
- Dry Storage Activity - Movement of loaded transfer cask and dry shielded canister.
- Hardened Containment Venting System in use.

REFERENCES

- Emergency Procedure 5.1RAD, Building Radiation Trouble.

REFUEL AREA HIGH RAD	PANEL/WINDOW: 9-3-1/A-10

1. OPERATOR OBSERVATION AND ACTION

1.1 IF associated indicator on Panel 9-11 is below alarm setpoint, THEN reset alarm.

NOTE – Step 1.2 is N/A for planned activities that may result in higher than normal radiation levels (e.g., radiography or authorized radioactive material movement) if an announcement was made prior to the evolution and Radiation Protection was informed.

1.2 IF associated indicator on Panel 9-11 remains above alarm setpoint, THEN perform following:

1.2.1 Notify Plant personnel to clear area via gaitronics.

1.2.2 Notify Radiation Protection to survey area.

1.2.3 Enter Procedure 5.1RAD.

EMERGENCY PROCEDURE 5.1RAD BUILDING RADIATION TROUBLE	EFFECTIVE: 11/20/15 APPROVAL: ITR-RDM OWNER: OSG SUPV DEPARTMENT: OPS

. ENTRY CONDITIONS ⓟ[4]

1.1 High or unusual readings on any ARM or ARM recorder.

1.2 Local area radiation alarms.

1.3 Portable radiation monitoring units indicate abnormally high readings.

1.4 High or unusual readings on the Reactor Building Ventilation monitors/recorders.

1.5 High or unusual readings on any building Kamans.

1.6 Local Continuous Air Monitor alarms.

1.7 Abnormal fuel pool water level.

. AUTOMATIC ACTIONS

2.1 None.

. IMMEDIATE OPERATOR ACTIONS

3.1 None.

. SUBSEQUENT OPERATOR ACTIONS

4.1 Record current time and date. Time/Date: ________/__________

NOTE 1 – Following scram, affected areas for RMA-RA-9, CRD HYDRAULIC EQUIP AREA (NORTH), include R-903-N, R-903-S, and R-931-SW.

NOTE 2 – Area Radiation Monitor alarms on refueling floor may be received when removing a Transfer Cask (TC) from spent fuel pool and Continuous Air Monitor alarms on refuel floor area may be received during vacuum drying of a Dry Shielded Canister (DSC).

4.2 Notify Plant personnel to clear affected area via gaitronics.

4.3 IF high radiation on refueling floor, THEN perform Attachment 1 (Page 3). ⓟ[4]

4.4 IF radiation due to known system leakage outside Secondary Containment, THEN enter Procedure 5.1BREAK.

4.5 Close all possible doors or barriers.

CNS OPERATIONS MANUAL EMERGENCY PROCEDURE 5.2FUEL FUEL FAILURE	QUALITY: QAPD RELATED EFFECTIVE: 1/16/19 APPROVAL: ITR-RDM OWNER: AOM-SUPPORT DEPARTMENT: OPS

PSE 2

Scram Actions

1. ENTRY CONDITIONS

   1.1 Unexplained rise in main steam line radiation.

   1.2 Unexplained rise in off-gas activity.

   1.3 Unexplained changes in core parameters (i.e., power, pressure, or core flow).

   1.4 Unexplained significant rise in plant background or airborne radioactivity (CAM).

   1.5 Higher than expected activity in reactor coolant sample.

   1.6 Irradiated fuel damage with release of radioactivity to secondary containment as indicated by HIGH alarm on refueling floor ARM #2, CAM, or Reactor Building ventilation monitor.

2. AUTOMATIC ACTIONS

   2.1 None.

3. IMMEDIATE OPERATOR ACTIONS

   3.1 None.

4. SUBSEQUENT OPERATOR ACTIONS

   4.1 Record current time and date. Time/Date: ________ / ___________

   4.2 Lower power, as required, to reduce off-gas and main steam line radiation levels.

   4.3 Check OWC Injection System for proper operation.

   4.4 **IF valid MAIN STM LINE HI HI RAD (9-4-1/A-4) alarm is actuated, THEN SCRAM and enter Procedure 2.1.5.**

   4.5 IF OFF-GAS TIMER INITIATED (9-4-1/C-4) alarm is actuated, THEN concurrently enter Procedure 2.4OG.

   4.6 IF valid MAIN STM LINE HI HI RAD (9-4-1/A-4) alarm is actuated and reactor is shut down, THEN close MSIVs and MSL drain valves.

Scram Actions

From EOP-5A

SECONDARY CONTAINMENT CONTROL

ANY OF FOLLOWING ENTRY CONDITIONS:

- Area temperature above maximum normal operating value, Secondary Containment Temperatures (TABLE 9)
- Rx Bldg exhaust plenum radiation level above 10 mr/hr
- Area radiation level above maximum normal operating value, Secondary Containment Radiation Levels (TABLE 10)
- Area water level above maximum normal operating value, Secondary Containment Water Levels (TABLE 11)
- Rx Bldg differential pressure at or above 0 in. H_20
- Access to secondary containment prohibited by elevated temperature, radiation, or water level
- Spent fuel pool temperature above 125°F
- Spent fuel pool level below -4 in. (37 ft. 3 in. or 37.25 ft)

10 SECONDARY CONTAINMENT RADIATION LEVELS SPDS 15 (5)

Maximum Normal Operating Value			Maximum Safe Operating Value		
Area	Any ARM Alarmed	Range (mR/hr)	Area	Value (mR/hr)	Actual Value
FUEL POOL AREA	RMA-RA-1	100 - 10^6	1001' El.	1000	
FUEL POOL AREA	RMA-RA-2	.01 - 100	1001' El.		
RWCU PRECOAT AREA	RMA-RA-4	0.1 - 1000	958' El.		
RWCU SLUDGE AND DECANT PUMP AREA	RMA-RA-5	0.1 - 1000	931' El.	1000	
CRD HYDRAULIC EQUIP AREA (SOUTH)	RMA-RA-8	.01 - 100	903' El.		
CRD HYDRAULIC EQUIP AREA (NORTH)	RMA-RA-9	.01 - 100			
HPCI PUMP ROOM	RMA-RA-10	.01 - 100	HPCI Room		
RHR PUMP ROOM, (SOUTHWEST)	RMA-RA-11	.01 - 100	SW Quad	1000	
TORUS HPV AREA (SOUTHWEST)	RMA-RA-27	1.0 - 10000	SW Torus		
RHR PUMP ROOM, (NORTHWEST)	RMA-RA-12	.01 - 100	NW Quad	1000	
RCIC/CORE SPRAY PUMP ROOM, (NORTHEAST)	RMA-RA-13	.01 - 100	NE Quad	1000	
CORE SPRAY PUMP ROOM, (SOUTHEAST)	RMA-RA-14	.01 - 100	SE Quad	1000	

9-3-1/A-9

SETPOINT	CIC
1. (1400) RX BLDG RWCU PRECOAT AREA RAD HIGH at 50 mR/Hr	1. RMA-RA-4
2. (1401) RX BLDG RWCU SLUDGE/DECANT PUMP AREA RAD HIGH at 5 mR/Hr	2. RMA-RA-5
3. (1402) RX BLDG TIP DRIVE MECH AREA RAD HIGH at 10 mR/Hr	3. RMA-RA-7
4. (1403) RX BLDG CRD SOUTH HCU AREA RAD HIGH at 5 mR/Hr	4. RMA-RA-8
5. (1404) RX BLDG CRD NORTH HCU AREA RAD HIGH at 60 mR/Hr	5. RMA-RA-9
6. (1405) RX BLDG HPCI PUMP ROOM AREA RAD HIGH at 5 mR/Hr	6. RMA-RA-10
7. (1406) RX BLDG RHR PUMP ROOM (SW) AREA RAD HIGH at 23 mR/Hr	7. RMA-RA-11
8. (1407) RX BLDG RHR PUMP ROOM (NW) AREA RAD HIGH at 50 mR/Hr	8. RMA-RA-12
9. (1408) RX BLDG RCIC/CS PUMP ROOM (NE) AREA RAD HIGH at 20 mR/Hr	9. RMA-RA-13
10. (1409) RX BLDG CS PUMP ROOM (SE) AREA RAD HIGH at 13 mR/Hr	10. RMA-RA-14
11. (1410) RX BLDG NEW FUEL STG AREA RAD HIGH at 2.3 mR/Hr	11. RMA-RA-3
12. (1456) RX BLDG SW TORUS AREA RAD HIGH at 30 mR/Hr	12. RMA-RA-27

PROBABLE CAUSES
- Steam and/or water leak.
- RWCU filter demineralizer backwash.
- RHR in the Shutdown Cooling Mode.
- HPCI operation.
- Crud burst.
- Dry Storage Activity - Movement of loaded transfer cask and dry shielded canister.

REFERENCES
- Technical Specification LCO 3.4.4, RCS Operational Leakage.
- Abnormal Procedure 2.4OG, Off-Gas Abnormal.
- Emergency Procedure 5.1RAD, Building Radiation Trouble.
- Emergency Procedure 5.2FUEL, Fuel Failure.

PROCEDURE 2.3_9-3-1 REVISION 39 PAGE 20 OF 131

REACTOR BLDG HIGH RAD

PANEL/WINDOW: 9-3-1/A-9

1. OPERATOR OBSERVATION AND ACTION

1.1 IF associated indicator on Panel 9-11 is below alarm setpoint, THEN reset alarm.

Examination Outline Cross-Reference	Level	RO
219000 (SF5 RHR SPC) RHR/LPCI: Torus/Suppression Pool Cooling Mode Knowledge of the operational implications of the following concepts as they apply to RHR/LPCI: TORUS/SUPPRESSION POOL COOLING MODE: K5.04 Heat exchanger operation	Tier#	2
	Group#	2
	K/A #	219000 K5.04
	Rating	2.9
	Revision	0
Revision Statement:		

Question 43 **From previous 2 NRC Exams** 9/2018 ILT NRC Q#57

RHR pump A is operating in Suppression Pool Cooling mode.

RHR A flow rate is 8400 gpm.

NO other RHR pumps are available.

IAW Procedure 2.2.69.3 [RHR Suppression Pool Cooling and Containment Spray], which one of the following actions is required to RAISE the cooldown rate?

A. Throttle closed MO-66A [HX BYPASS VLV]

B. Throttle open MO-12A [HX-A OUTLET VLV]

C. Throttle closed MO-38A [TORUS SPRAY INBD THROTTLE VLV]

D. Throttle open MO-34A [SUPPR POOL COOLING INBD THROTTLE VLV]

Answer: A
Explanation: RHR A flow is at the maximum flow limit to prevent pump runout per procedure 2.2.69.3 step 2.7. Throttling closed MO-66A will force more flow through the RHR HX, resulting in greater heat removal and cooldown rate.
Distracters: Answer B is plausible because opening MO-12A is an option in SDC mode per procedure 2.2.69.2 and would result in more flow through the HX, thus more cooling. The examinee who confuses SDC mode with SPC mode may choose this answer. It is wrong because MO-12A is fully open in SPC mode and because opening MO-12A, if possible, would result in RHR flow rising above 8400 gpm, which is the upper flow limit to prevent pump runout.

Answer C is plausible because the examinee might not know the RHR piping arrangement or lineup for SPC. It is wrong because MO-38A is already closed for SPC mode, so this action will not raise cool down rate. Answer D is plausible because if additional cooling is required, procedure 2.2.69.3 states pump C in the same RHR loop may be started and MO-34A throttled further open to achieve more flow. It is wrong because only one RHR pump is operating, and raising flow will cause pump runout.		
Technical References: procedure 2.2.69.3 [RHR Suppression Pool Cooling and Containment Spray](Rev 51), procedure 2.2.69.2 [RHR System Shutdown Operations](rev 106)		
References to be provided to applicants during exam: none		
Learning Objective: COR002-23-02 Obj LO-5d, Briefly describe the following concepts as they apply to the RHR system: Heat exchanger operation		
Question Source:	Bank # **From previous 2 NRC Exams**	9/2018 ILT NRC Q#57
(note changes; attach parent)	Modified Bank #	
	New	
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(7),(10)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA Applicability:		
Top 10 Risk Significant System – RHR SPC		

9-2018 ILT NRC Q#57

Question 57

RHR pump A is operating in Suppression Pool Cooling mode.

RHR A flow rate is 8400 gpm.

NO other RHR pumps are available.

IAW Procedure 2.2.69.3 [RHR Suppression Pool Cooling and Containment Spray], which one of the following actions is required to RAISE the cooldown rate?

A. Throttle closed MO-38A [TORUS SPRAY INBD THROTTLE VLV]

B. Throttle closed MO-66A [HX BYPASS VLV]

C. Throttle open MO-12A [HX A OUTLET VLV]

D. Throttle open MO-34A [SUPPR POOL COOLING INBD THROTTLE VLV]

Answer: B.

1. PURPOSE

   1.1 Operate Residual Heat Removal (RHR) System Suppression Pool Cooling and Containment Spray Modes.

2. PRECAUTIONS AND LIMITATIONS

   2.1 Suppression Pool in excess of normal operating temperature limit requires all available Suppression Pool cooling.

      2.1.1 One RHR Subsystem in Suppression Pool cooling at or before 95°F.

      2.1.2 Two RHR Subsystems one pump per subsystem at or before 100°F.

   2.2 RHR HX relief valves set at 450 psig.

   2.3 Inadvertent drywell spray may occur during testing or other off-normal conditions.

   2.4 RHR pump minimum flow operation limited to less than 15 minutes.

   2.5 RHR pump damage may result from minimum flow operation greater than 15 minutes.

   2.6 RHR pump rated flow rate, 7700 to 8400 gpm.

   2.7 RHR pump run out may occur at flow rates in excess 8400 gpm.

   2.8 RHR pump discharge pressure may cause RHR-MO-25A or RHR-MO-25B outboard disc to flex open in MODE 4 or 5.

      2.8.1 Outboard disc flexing is an expected design condition.

      2.8.2 RPV level may rise due to leakage past RHR-MO-25A or RHR-MO-25B via flow path created through RHR-66 or RHR-74 to RPV.

   2.9 OPERABLE LPCI Mode requires maintaining RHR-MO-20 closed.

3.18 IF manual override required for 2/3 Core Valve Control Permissive, THEN **PERFORM** following:

3.18.1 **OBTAIN** CRS permission.

3.18.2 **PLACE** CONTMT COOLING 2/3 CORE VALVE CONTROL PERMISSIVE switch to MANUAL OVERRD.

3.19 IF manual containment cooling valve control required, THEN **PLACE** CONTMT COOLING VLV CONTROL PERMISSIVE switch to MANUAL.

3.20 **OPEN** RHR-MO-39A, SUPPR POOL COOLING/TORUS SPRAY VLV.

3.21 IF following exist:
- RPV less than or equal to 300 psig.
- Injection not desired.

THEN **CLOSE** RHR-MO-27A, OUTBD INJECTION VLV.

NOTE 1 – RHR-MO-16A, LOOP A MIN FLOW BYP VLV, remains open when RHR Subsystem A less than or equal to 2107 gpm.

NOTE 2 – Reactor Building high ambient temperature may cause Suppression Pool temperature to rise before lowering.

CAUTION – RHR pump damage may occur from minimum flow operation greater than 15 minutes.

3.22 **START** RHR Pump A or C.

3.23 **THROTTLE OPEN** RHR-MO-34A, SUPPR POOL COOLING INBD THROTTLE VLV, to obtain rated cooling flow or as directed by CRS.

3.24 **ENSURE** RHR-MO-16A closed.

3.25 **PERFORM** one of following:

3.25.1 **CLOSE** CM-296, LOOP A INJECTION LINE PRESSURE MAINTENANCE SHUTOFF (R-881-NW Quad).

CAUTION – Suppression Pool filling may occur if RHR Subsystem pressure less than Condensate Transfer System pressure.

3.25.2 **MAINTAIN** RHR Subsystem A pressure greater than Condensate Transfer System pressure.

3.26 **THROTTLE CLOSE** RHR-MO-66A, HX BYPASS VLV, to obtain desired cooling rate.

NOTE – When starting REC pump, it is normal for associated pump low pressure alarm to come in and immediately clear.

3.27 IF all of following apply:
- REC-MO-711 closed.
- REC-MO-714 closed.
- Pressure indicated on REC-PI-452, REC HEADER PRESSURE (Panel M), less than 74 psig.

THEN **START** an idle REC pump.

3.28 IF following exist:
- Panel 9-5 PCIS Group 6 lights lit.
- Only REC HX A in service.

THEN at VBD-M, **ENSURE** REC-MO-711, CRITICAL LOOP SUPPLY, open.

3.29 IF following exist:
- Panel 9-5 PCIS Group 6 lights lit.
- Only REC HX B in service.

THEN at VBD-M, **ENSURE** REC-MO-714, CRITICAL LOOP SUPPLY, open.

3.30 IF following exist:
- Panel 9-5 PCIS Group 6 lights lit.
- Both REC HXs in service.

THEN at VBD-M, **ENSURE** one of following open:

- REC-MO-711.
- REC-MO-714.

3.31 IF additional cooling required and RHR Subsystem B available, THEN **PLACE** RHR Subsystem B in Suppression Cooling per Section 7.

3.32 IF additional cooling still required, THEN **PERFORM** following:

3.32.1 **START** non-running RHR Pump A or C.

NOTE – Suppression Pool cooling not limited to 11,550 gpm during accident conditions.

3.32.2 **THROTTLE** RHR-MO-34A to less than or equal to 11,550 gpm. ®[3]

4.32 Throttle RHR-MO-27A until a slight reduction in RHR Subsystem A flow observed.

4.33 Open RHR-MO-66A.

4.34 Throttle RHR-MO-27A to obtain an RHR Subsystem A flow of 7700 to 8400 gpm or 5000 to 7000 gpm if fuel or blade guides removed from around dry tubes.

4.35 Commence monitoring plant heatup/cooldown rate per Procedure 6.RCS.601.

__NOTE__ – Following steps should be performed slowly to minimize HX thermal shock.

4.36 Adjust RHR Subsystem A flow using following valves to ensure average heatup/cooldown rate ≤ 90°F/hr averaged over any 1 hour period: Ⓟ[3]

4.36.1 RHR-MO-27A.

4.36.2 RHR-MO-66A.

4.36.3 RHR-MO-12A.

4.37 Continue to monitor following while SDC in-progress:

4.37.1 RPV level ≥ 48", unless following exception taken:

4.37.1.1 If in MODE 3 or 4, level may be lowered:

a. As directed by other procedure; __or__

b. If a RR pump operating, in preparation for transitioning to MODE 2 (Mode Switch to Startup).

4.37.2 SDC flow shall __not__ be < 5000 gpm to provide adequate mixing.

4.37.3 Reactor coolant temperature ≥ 68°F at all times due to reactivity analysis.

4.37.4 Reactor coolant, RPV flange, and RPV head temperatures > 70°F when vessel head tensioned to maintain pressure/temperature curve limits.

4.37.5 IF lowering RPV pressure for plant cooldown per Procedure 2.1.4 or 2.1.20.3, THEN ensure following prior to RPV pressure lowering to 5 psig: Ⓟ[16]

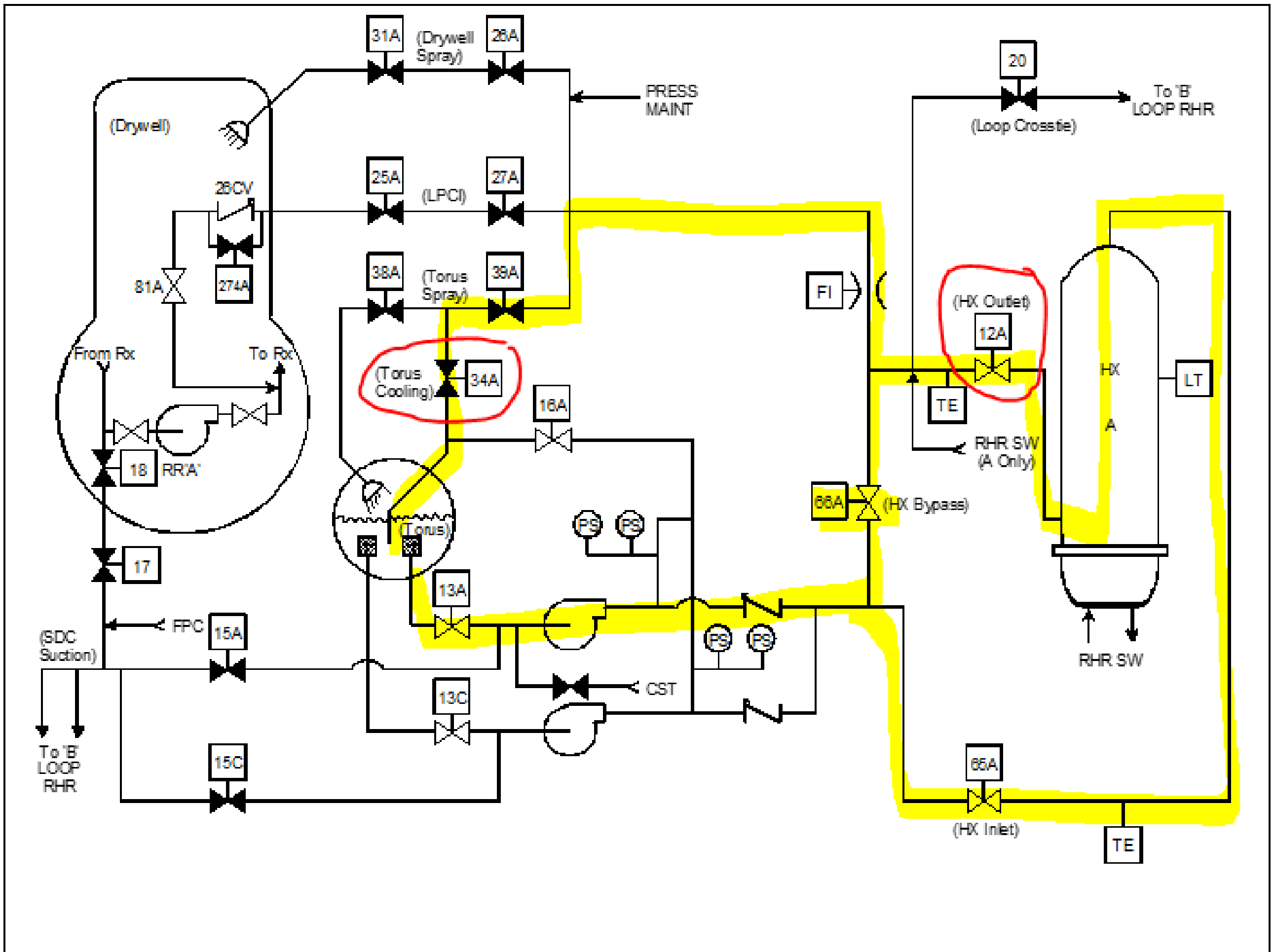
4.37.5.1 Personnel pre-staged to isolate main steam lines.

4.37.5.2 Personnel pre-staged to unisolate and open vessel head vents.

4.37.6 RHR SW Subsystem A for proper operation.

4.37.7 SW Process Radiation Monitoring System.

4.37.8 REACTOR VESSEL METAL TEMPERATURE RECORDER NBI-TR-89 (Panel 9-21) for indication of stratification. IF stratification occurs, THEN take action per Procedure 2.4RR.



RHR LOOP 'A'

Figure 1, Rev. 9

COR002-23-02

Examination Outline Cross-Reference	Level	RO
295030 (EPE 7) Low Suppression Pool Water Level / 5 2.2.40 Ability to apply Technical Specifications for a system.	Tier#	1
	Group#	1
	K/A #	295030 G2.2.40
	Rating	3.4
	Revision	0
Revision Statement:		

Question 44

The plant is in Mode 3.

Which one of the following is the LOWEST value indicated on PC-LI-12 [TORUS LEVEL] that satisfies (does NOT require entry into Conditions of) TS LCO 3.6.2.2 [Suppression Pool Water Level]?

A. +0.1 inches

B. -1.4 inches

C. -1.9 inches

D. -4.0 inches

Answer: C

Explanation:
TS 3.6.2.2 requires SP water level to be ≥12 ft 7 inches and ≤12 ft 11 inches. This is equivalent to ≥-2.0 inches and ≤+2.0 inches on PC-LI-12 [TORUS LEVEL]. The lowest answer that is ≥-2.0 inches is C, -1.9 inches.

Distracters:
Answer A is plausible because, of the answers given, it is the lowest positive value. An examinee may believe a negative value constitutes being below the TS minimum and choose this answer. It is wrong because it is not the lowest value given that satisfies TS 3.6.2.2.

Answer B is plausible because it is the lowest value that is above the setpoint for SP Level Low annunciator 9-3-2/G-5. The examinee who knows the alarm setpoint and believes it represents the TS 3.6.2.2 minimum water level. It is wrong for the same reason stated for distractor A.

Answer D is plausible for the same reason given for distractor B and because the low SP level alarm corresponds to -5 inches on wide range SP level indicator PC-LI-10. It is wrong because -4.0 inches on PC-LI-12 is below the TS 3.6.2.2 minimum required SP level.

Technical References: TS 3.6.2.2 [Suppression Pool Water Level], Alarm card 9-3-2/G-5 [Suppr Pool NR/WR Low Level](Rev 34), Procedure 6.LOG.601 [Daily Surveillance Log – Modes 1, 2, and 3](Rev 139)

References to be provided to applicants during exam: none

Learning Objective: INT007-05-07 EO-1, Given a set of plant conditions, recognize non-compliance with a Chapter 3.6 LCO.

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(10)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	

PSA Applicability:
Top 10 Risk Significant System – Primary Containment

3.6 CONTAINMENT SYSTEMS

3.6.2.2 Suppression Pool Water Level

LCO 3.6.2.2 Suppression pool water level shall be ≥ 12 ft 7 inches and ≤ 12 ft 11 inches.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Suppression pool water level not within limits.	A.1	Restore suppression pool water level to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	12 hours
	AND		
	B.2	Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.2.1	Verify suppression pool water level is within limits.	In accordance with the Surveillance Frequency Control Program

ATTACHMENT 20 SURVEILLANCE AND LCO REFERENCES

NOTE	SURVEILLANCE REQUIREMENT	LCO
55	SR 3.6.1.4.1	LCO 3.6.1.4
56	SR 3.6.1.5.1	LCO 3.6.1.5
57	SR 3.6.2.1.1	LCO 3.6.2.1
58	SR 3.6.2.2.1	LCO 3.6.2.2
59	SR 3.6.3.1.1	LCO 3.6.3.1
60	SR 3.6.4.1.1	LCO 3.6.4.1
61	SR 3.7.2.1	LCO 3.7.2
62	SR 3.7.2.2	LCO 3.7.2
63	SR 3.7.3.1	LCO 3.7.3
64	SR 3.7.3.2	LCO 3.7.3
65	SR 3.7.6.1	LCO 3.7.6
66	SR 3.4.7.1	LCO 3.4.7
67	SR 3.10.2.1	LCO 3.10.2
68	SR 3.10.2.2	LCO 3.10.2
69	SR 3.10.3.2	LCO 3.10.3
70	SR 3.10.3.3	LCO 3.10.3
71	SR 3.2.3.1	LCO 3.2.3
72	DSR 3.2.7.1	DLCO 3.2.7
73	TSR 3.3.1.1	Table T3.3.1-1, Function 1b
74	TSR 3.3.1.1	Table T3.3.1-1, Function 1d
75	TSR 3.3.1.1	Table T3.3.1-1, Function 2a
76	TSR 3.3.1.1	Table T3.3.1-1, Function 2b
77	TSR 3.3.1.1	Table T3.3.1-1, Function 2d
78	TSR 3.3.1.1	Table T3.3.1-1, Function 3a
79	TSR 3.3.1.1	Table T3.3.1-1, Function 3b
80	TSR 3.3.1.1	Table T3.3.1-1, Function 3c
81	TSR 3.3.1.1	Table T3.3.1-1, Function 3d
82	TSR 3.3.3.1	Table T3.3.3-1, Function 1

LOC	INSTRUMENT NUMBER	PDD	0730-1030 READING	1930-2230 READING	OPERABILITY LIMIT	MAX Δ	APPLICABLE MODES	ATT. 20 NOTES
PNL 9-3	PC-LI-13				≤ +2" and ≥ -2"	0.5"	1, 2, 3	58, 85
PNL 9-3	PC-LI-12							

PNL 9-3	PC-LI-10				N/A	0.5'	1, 2 (a)	84
PNL 9-3	PC-LR-11							

AVERAGE DRYWELL TEMPERATURE (a)		MCO		≤ 150°F	N/A	1, 2, 3	56

Notes on Attachment 5

(a) **RECORD** readings regardless of specified MODE.

SUPPR POOL NR/WR LOW LEVEL	PANEL/WINDOW: 9-3-2/G-5

1. OPERATOR OBSERVATION AND ACTION

NOTE – -2" on PC-LI-12 is calculated equivalent to Tech Spec LCO 87,650 ft^3, minimum water volume for suppression pool.

1.1 Prior to exceeding -2" on PC-LI-12, stop activities draining water from suppression pool.

1.2 Perform suppression pool makeup per Procedure 2.2.69.3.

SETPOINT	CIC	9-3-2/G-5
1. (1722) SUPR POOL NR LEVEL LOW (PC-LI-12) at -1.5"	1. PC-LA-12	
2. (1723) SUPR POOL WR LEVEL LOW (PC-LI-10) at -5"	2. PC-LA-10	

PROBABLE CAUSES
- Torus water transfer per weekly schedule.
- Extended operation of CSCS.

REFERENCES
- Technical Specifications LCO 3.3.3.1, Post-Accident Monitoring (PAM) Instrumentation.
- Technical Specifications LCO 3.6.2.2, Suppression Pool Water Level.
- NEDC 97-088.
- NEDC 97-091A.
- PSTG Input Data WLsp-nr.
- System Operating Procedure 2.2.69.3, RHR Suppression Pool Cooling and Containment Spray.

Examination Outline Cross-Reference	Level	RO
295016 (APE 16) Control Room Abandonment / 7 Knowledge of the interrelations between CONTROL ROOM ABANDONMENT and the following: AK2.01 Remote shutdown panel: Plant-Specific	**Tier#**	1
	Group#	1
	K/A #	295016 AK2.01
	Rating	4.4
	Revision	0
Revision Statement:		

Question 45

Which one of the following actions can be performed **ENTIRELY** by the ASD Operator from the Alternate Shutdown panel in the event the Control Room becomes uninhabitable due to toxic fumes during Mode 1?

A. Prevent RCIC injection

B. Operate <u>all</u> Low-Low Set valves

C. Place HPCI in pressure control mode

D. Place RHR Suppression Pool Cooling in service

Answer: C

Explanation:
Of the actions listed, only HPCI has all controls necessary for pressure control mode located on ASD panels. Other listed actions are either fully or in part only performed from locations other than the ASD panel room.

Distracters:
Answer A is plausible because this action is performed from outside of the control room for control room abandonment. Like ASD panel actions, this action is also performed from a location in the control building. It is wrong because it is accomplished by the control building operator placing the RCIC ISOLATION switch to ISOLATE in the Auxiliary Relay Room.

Answer B is plausible because there are two LLS SRVs and there are controls for three SRVs on the ASD panel. It is wrong because only one LLS SRV (71F) can be controlled from the ASD panel.

Answer D is plausible because controls for all RHR loop B valves necessary to establish the SPC lineup are located on the ASD panel. It is wrong because RHR

Pump D used for SPC is not controlled from the ASD panel but must be started locally at the pump breaker in the critical switchgear room, and RHRSW to RHR B heat exchanger is aligned from locations other than the ASD room.		
Technical References: Procedure 5.1ASD [Alternate Shutdown](Rev 19), Lesson plan COR002-16-02 [Ops Nuclear Pressure Relief](Rev 21)		
References to be provided to applicants during exam: none		
Learning Objective: COR002-34-02 Obj LO-9, List the components that can be operated from the ASD room.		
Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(7)	
Level of Difficulty:	2	
SRO Only Justification:	N/A	
PSA Applicability:		
Top 10 Risk Significant Systems – HPCI, RHR, ADS/SRV		

ATTACHMENT 1 ASD OPERATOR

ATTACHMENT 1 ASD OPERATOR

1. Establish RPV level/pressure indications at HPCI ASD Panel by performing following:

   1.1 Place following ISOLATION switches in ISOL:

   1.1.1 LEVEL INDICATORS.

   1.1.2 HPCI CONTROL AND INDICATION.

   1.1.3 MO-15.

   1.1.4 MO-16.

2. Direct Control Building Operator to place RCIC ISOLATION SWITCH to ISOL per Attachment 2, Step 1.

3. IF subsequent Operator Actions in Step 4.3 of procedure body were completed in Control Room, THEN go to Step 7.

4. IF subsequent Operator Actions in Step 4.3 of procedure body were not completed in Control Room, THEN perform Steps 5 and 6 concurrently with Step 7.

NOTE – Steps 5 and 6 must be performed in sequence listed. Inform ASD Operator immediately when each task is complete.

5. Direct following personnel to perform specified tasks:

   5.1 Control Building Operator scram reactor per Attachment 2, Step 2.

   5.2 Reactor Building Operator check all HCU scram inlet and outlet valves open per Attachment 5, Step 1.

6. WHEN Step 5 actions completed, THEN direct following personnel to perform specified task in order given:

   6.1 Turbine Building Operator trip Main Turbine per Attachment 3, Step 1.

   6.2 IF two RFPs running, THEN direct Diesel Generator Operator to trip per Attachment 4, Step 1.1, RFP not controlling level.

   6.3 Turbine Building Operator leave one condensate booster pump running (A or B preferred) and trip remaining condensate booster pump(s) per Attachment 3, Step 3.

   6.4 Turbine Building Operator leave one condensate pump running (A or B preferred) and trip remaining condensate pump(s) per Attachment 3, Step 4.

   6.5 Control Building Operator trip running RRMG Set(s) per Attachment 2, Step 5.

6.6 Reactor Building Operator open REC-MO-714, SOUTH CRITICAL LOOP SUPPLY, per Attachment 5, Step 2.

7. Operate HPCI System by performing following:

NOTE – Attachment 6, Corrected Level Graphs, may be used to aid ASD Operator in determination of actual water level.

7.1 Before RPV level rises to +40" on NBI-LI-185B:

7.1.1 Direct Diesel Generator Operator trip running RFP(s) per Attachment 4, Step 1.2.

7.1.2 Direct Turbine Building Operator trip running condensate booster pump(s) per Attachment 3, Step 3.

7.1.3 Direct Reactor Building Operator trip RCIC turbine if running per Attachment 5, Step 3.

7.1.4 Direct Control Building Operator trip running CRD pump per Attachment 2, Step 6.

7.2 IF HPCI speed is indicated on HPCI-SI-2793, TURBINE SPEED, THEN go to Step 7.4.

7.3 IF HPCI is not running, THEN perform following:

7.3.1 Place remaining ISOLATION switches in ISOL on HPCI ASD Panel.

7.3.2 Ensure following valves closed:

NOTE – HPCI-MO-58 will not close unless HPCI-MO-17 indicates open.

7.3.2.1 HPCI-MO-14, STM TO TURBINE VLV.

7.3.2.2 HPCI-MO-19, INJECTION VALVE.

7.3.2.3 HPCI-MO-25, MIN FLOW BYP VLV.

7.3.2.4 HPCI-MO-58, TORUS PUMP SUCT VLV.

a. IF HPCI-MO-58 open and ECST available, THEN perform following:

1. Place HPCI-MO-17 control switch ECST PUMP SUCT VLV to OPEN.

2. WHEN HPCI-MO-17 indicates open, THEN immediately place HPCI-MO-58 control switch TORUS PUMP SUCT VLV to CLOSE.

7.3.3 Ensure following valves open:

7.3.3.1 HPCI-MO-17, ECST PUMP SUCT VLV.

7.3.3.2 HPCI-MO-20, PUMP DISCH VLV.

7.3.3.3 HPCI-MO-24, ECST TEST LINE SHUTOFF VLV.

7.3.3.4 HPCI-MO-21, TEST BYPASS TO ECST VLV.

7.3.4 Place HPCI ROOM FC-R-1G control switch to RUN.

7.3.5 Place GLAND SEAL CNDSR BLOWER control switch to AUTO.

7.3.6 Place GLAND SEAL CNDSR COND PUMP control switch to AUTO.

7.3.7 Ensure FLOW CONTROLLER HPCI-FIC-1108 setpoint (FLOW.S) set to 4250 gpm.

7.3.8 Depress FLOW CONTROLLER HPCI-FIC-1108 A/M button until light next to "M" illuminated.

7.3.9 Open HPCI-MO-14.

7.3.10 Place AUXILIARY OIL PUMP control switch to START.

7.3.11 Ensure turbine speed is > 2050 rpm on HPCI-SI-2793 by adjusting FLOW CONTROLLER HPCI-FIC-1108 using adjusting knob.

7.3.12 Have Reactor Building Operator check REC flow indicated on REC-FIS-24, OUTLET REC FLOW IND SWITCH (R-859-HPCI RM NW inside Panel TB221).

7.3.13 Go to Step 8.

NOTE – Step 7.4 should be performed ONLY if HPCI turbine was in operation at Step 7.2.

7.4 IF HPCI running, THEN transfer control by performing following:

7.4.1 At HPCI ASD Panel, place following switches in position stated:

7.4.1.1 AUXILIARY OIL PUMP control switch in AUTO.

7.4.1.2 GLAND SEAL CNDSR COND PUMP control switch in AUTO.

7.4.1.3 GLAND SEAL CNDSR BLOWER control switch in AUTO.

7.4.1.4 HPCI ROOM FC-R-1G control switch in RUN.

7.4.2 Ensure FLOW CONTROLLER HPCI-FIC-1108 set to 4250 gpm (FLOW.S) and in AUTO.

7.4.3 At HPCI ASD Panel, place all remaining ISOLATION switches to ISOL.

7.4.4 Ensure turbine speed > 2050 rpm on HPCI-SI-2793 by adjusting HPCI FLOW CONTROLLER HPCI-FIC-1108 setpoint using adjusting knob.

7.4.5 Ensure following valves open:

7.4.5.1 HPCI-MO-14, STM TO TURB VLV.

7.4.5.2 HPCI-MO-17, ECST PUMP SUCT VLV.

a. IF HPCI-MO-17 closed and ECST available, THEN perform following:

1. OPEN HPCI-MO-17.
2. WHEN HPCI-MO-17 indicates open, THEN immediately CLOSE HPCI-MO-58.

7.4.5.3 HPCI-MO-20, PUMP DISCH VLV.

7.4.5.4 HPCI-MO-21, TEST BYPASS TO ECST VLV.

7.4.5.5 HPCI-MO-24, ECST TEST LINE SHUTOFF VLV.

7.4.6 Ensure following valves closed:

7.4.6.1 HPCI-MO-19, INJECTION VALVE.

7.4.6.2 HPCI-MO-25, MIN FLOW BYP VLV.

7.4.6.3 HPCI-MO-58, TORUS PUMP SUCT VLV.

7.4.7 Have Reactor Building Operator check REC flow indicated on REC-FIS-24, OUTLET REC FLOW IND SWITCH (R-859-HPCI RM NW inside Panel TB221).

8. Control RPV level/pressure with HPCI and ADS valves by performing following:

8.1 Monitor RPV level and perform Steps 8.2 through 8.5, as required, to maintain RPV level < +40" on NBI-LI-185B.

NOTE 1 – SRVs may be used to assist controlling RPV pressure only if N_2 supply can be assured. If N_2 supply cannot be assured, Step 8.2 is N/A.

NOTE 2 – When SRV(s) opened and closed, expect RPV level swing up to ~ 20".

8.2 Use SRVs to assist in controlling RPV pressure as follows:

8.2.1 Place VALVES 71E, 71F, 71G Isolation switch to ISOL.

8.2.2 OPEN one or more of following valves to lower RPV pressure:

8.2.2.1 MS-71E, TORUS SE VLV.

8.2.2.2 MS-71F, TORUS SE VLV.

8.2.2.3 MS-71G, TORUS SW VLV.

8.2.3 CLOSE valve(s) to allow RPV pressure rise.

CAUTION – Throttling HPCI-MO-21 closed to lower flow/raise discharge pressure may lower HPCI turbine speed.

NOTE – HPCI turbine will only trip on overspeed (~ 5000 rpm) or manual trip. High level trip will not function.

8.3 Perform following concurrently:

8.3.1 Maintain turbine speed between 2050 and 4000 rpm.

8.3.1.1 IF in AUTO, THEN adjust HPCI FLOW CONTROLLER HPCI-FIC-1108 setpoint (FLOW.S) using adjusting knob.

8.3.1.2 IF in MANUAL, THEN adjust HPCI FLOW CONTROLLER HPCI-FIC-1108 using adjusting knob.

8.3.2 Adjust turbine speed on HPCI-SI-2793 to maintain following rates:

8.3.2.1 Limit rate of depressurization to 50°F for first hour.

8.3.2.2 Limit rate of depressurization to 90°F/hr average over any 1 hour for hour 2 and beyond.

8.3.3 Throttle closed HPCI-MO-21 to raise pump discharge pressure on HPCI-PI-1109, PUMP DISCHARGE, to approximately RPV pressure on HPCI-PI-1111, TURBINE STEAM.

8.4 Open HPCI-MO-19.

8.5 Throttle HPCI-MO-21 and/or open and close HPCI-MO-19, as required, to maintain RPV level in desired band.

NOTE – Remainder of Step 8 is performed concurrently with Step 9 to control RPV and Containment parameters.

8.6 Start torus cooling per Step 9, as required, to maintain torus water temperature < 110°F on TORUS NW PC-TI-2A, TORUS NE PC-TI-2C, TORUS SE PC-TI-2E, or TORUS SW PC-TI-2G (ASD ADS/REC Panel).

ATTACHMENT 8 INFORMATION SHEET

1. DISCUSSION

1.1 This procedure contains basic steps to achieve a safe shutdown of reactor from outside the Control Room. Normal station operating procedures, as contained in the Operations Manual, should be followed as much as possible. Details to supplement the above procedures are contained in Attachments 1 through 5.

1.2 Control Room Supervisor shall be stationed in ASD Room. ASD Operator transfers HPCI and RHR Panel controls to ASD Panels. ASD Operator then uses HPCI System to maintain reactor vessel level and pressure, and RHR Loop B in suppression cooling mode to maintain pool temperature within limits.

1.3 Control Building Operator places RCIC ISOLATION switch to ISOLATE to prevent RCIC from initiating on low RPV water level and performs actions to scram reactor if it was not performed in Control Room. Operator then proceeds to Critical Switchgear Room and informs ASD Operator of status of 4160V Buses 1F and 1G, and operates breakers at the buses as directed by the ASD Operator.

1.4 Turbine Building Operator trips main turbine if it was not tripped in Control Room and then proceeds to Non-Critical Switchgear Room. Operator then informs ASD Operator of status of 4160V Buses 1A and 1B, and operates breakers at the buses as directed by ASD Operator.

1.5 Diesel Generator Operator trips operating reactor feed pumps to prevent reactor vessel overfill and then proceeds to Diesel Generator Rooms. Operator then informs ASD Operator of status of DG-1 and DG-2, and then shuts down DGs or monitors their operations as directed by ASD Operator.

1.6 Reactor Building Operator verifies scram if it was not performed in Control Room and then trips RCIC System if it is running to prevent reactor vessel overfill. Operator then proceeds to MCC-Y LASP and opens SW-MO-89B as directed by ASD Operator.

1.7 Any time Control Room is uninhabitable for any reason, entry into Station Emergency Plan is required. Shift Manager, STE, and Shift Communicator will proceed to TSC to perform Emergency Plan activities until relieved by ERO personnel.

1.8 PROBABLE CAUSE

1.8.1 None.

2. REFERENCES

2.1 PROCEDURES

2.1.1 System Operating Procedure 2.2.8, Control Rod Drive Hydraulic System.

2.1.2 System Operating Procedure 2.2.20, Standby AC Power System (Diesel Generator).

8.9.5 IF RPV pressure on HPCI-PI-1111 rises to > 500 psig <u>or</u> RPV level drops to +20" on NBI-LI-185B, THEN place HPCI turbine back in service per Step 7.3 and control RPV level/pressure per Step 8.

9. Start torus cooling by performing following:

9.1 Place all RHR ISOLATION switches in ISOL.

9.2 Ensure following valves closed:

9.2.1 RHR-MO-15D, PUMP D SDC SUCT VLV.

9.2.2 RHR-MO-16B, LOOP B MIN FLOW BYP VLV.

9.2.3 RHR-MO-27B, OUTBD INJECTION VLV.

9.2.4 RHR-MO-34B, SUPPR POOL COOLING INBD THROTTLE VLV.

9.3 Ensure following valves open:

9.3.1 RHR-MO-13D, PUMP D TORUS SUCT VLV.

9.3.2 RHR-MO-12B, HX OUTLET VLV.

9.3.3 RHR-MO-39B, SUPPR POOL COOLING/TORUS SPRAY OUTBD VLV.

9.3.4 RHR-MO-65B, HX INLET VLV.

9.3.5 RHR-MO-66B, HX BYPASS VLV.

9.4 Direct Reactor Building Operator to open SW-MO-89B per Attachment 5, Step 4.

9.5 WHEN SW-MO-89B is opened off its seat, THEN direct Control Building Operator to start SWB Pump B or D per Attachment 2, Step 5.

<u>CAUTION</u> – Step 9.7 must be performed within 10 seconds after Step 9.6 to prevent RHR pump overheating.

9.6 Direct Control Building Operator to start RHR Pump D per Attachment 2, Step 5.

<u>NOTE</u> – RHR pump operation at minimum flow should be limited to < 15 minutes or pump damage may result.

9.7 Throttle open RHR-MO-34B to raise flow > 2500 gpm on RHR-FI-1133B.

9.8 Direct Control Building Operator to monitor RHR Pump D motor amps as RHR-MO-34B is throttled open to maintain < 157 amps.

9.9 Raise RHR flow to between 4000 and 7000 gpm on RHR-FI-1133B.

8.2 Use SRVs to assist in controlling RPV pressure as follows:

8.2.1 Place VALVES 71E, 71F, 71G Isolation switch to ISOL.

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ATTACHMENT 1	ASD OPERATOR

8.2.2 OPEN one or more of following valves to lower RPV pressure:

8.2.2.1 MS-71E, TORUS SE VLV.

8.2.2.2 MS-71F, TORUS SE VLV.

8.2.2.3 MS-71G, TORUS SW VLV.

8.2.3 CLOSE valve(s) to allow RPV pressure rise.

Lesson Title: OPS Nuclear Pressure Relief	
Lesson Number: COR002-16-02	Revision Number: 21

LO-05a

b. ADS may be secured, or prevented from actuating, at any time by placing the ADS A and B Inhibit switches to the "INHIBIT" position. Depressing the ADS Logic A and B Timer Reset pushbuttons will secure the ADS blowdown, if in progress, and will reset the timers to zero. If the initiating conditions still exist, the timer will begin timing down again immediately after it has been reset. Securing all low pressure injection pumps (CS and LPCI) will also cause the ADS to stop a blowdown in progress.

c. ADS logic is powered from 125V DC, with Channel A powered from Panel AA2 and Channel B from Panel BB2. Channel B will automatically transfer to Panel AA2 on loss of power. Channel A does not have an automatic power supply backup.

E. Low-Low Set (LLS)

1. Upon initiation, LLS will lower the opening and closing setpoints of 2 SRVs by using RPV pressure switches to energize/de-energize the solenoid control valve to the pneumatic actuator of the SRV. The LLS pressure setpoints are:

Valve	Open	Close
RV-71 D	≥966.5 psig and ≤1010 psig	≥835 psig and ≤875.5 psig
RV-71 F	≥996.5 psig and ≤1040 psig	≥835 psig and ≤875.5 psig

LO-01c, 05c

2. The LLS will mitigate SRV subsequent actuation induced loads. The opening and closing setpoints for Low-Low Set relief are spread farther apart than for normal relief. This allows for more steam (energy) to be released each time an SRV opens. More energy will be required for repressurization before an SRV reopens and the number of SRV cycles are reduced.

ATTACHMENT 2 CONTROL BUILDING OPERATOR

NOTE – Operate plant equipment only when directed by ASD Operator.

1. When directed, go to Auxiliary Relay Room and place RCIC ISOLATION switch to ISOL (Panel 9-30).

2. If directed, **SCRAM** by performing following:

NOTE – Following steps de-energize both RPS buses causing a scram and Group 1, 2, 3, 6, and 7 isolations.

2.1 In 24 V 1A BATTERY AND SWGR ROOM, perform following:

2.1.1 On CDP-1A, place Breaker 2, BACKUP FEEDER TO REACTOR PROTECTION SYSTEM POWER PANEL RPSPP-1B, to OFF.

2.1.2 On Reactor Protec Sys Mot and Gen Set #1A Control Cubicle, place AC INPUT MOT breaker to OFF.

2.2 In 24 V 1B BATTERY AND SWGR ROOM, perform following:

2.2.1 On CDP-1B, place Breaker 9, BACKUP FEEDER TO REACTOR PROTECTION SYSTEM POWER PANEL RPSPP-1A, to OFF.

2.2.2 On Reactor Protec Sys Mot and Gen Set #1B Control Cubicle, place AC INPUT MOT breaker to OFF.

3. Go to Critical Switchgear Room and perform following:

3.1 Determine if 4160V Bus 1F is energized by observing voltage on meter on Compartment SS1F, 4160V BUS 1F FEED TO 480V BUS 1F.

3.1.1 IF no voltage indicated on meter, THEN notify ASD Operator and go to Step 3.2.

3.1.2 IF indicated voltage < 4050V, THEN inform ASD Operator entry conditions for Procedure 5.3GRID met.

3.1.3 IF voltage indicated, THEN determine power supply for 4160V Bus 1F as follows:

3.1.3.1 If powered from Startup Transformer, Breaker EE-CB-4160F(1FA), 4160V BUS 1A FEED TO 4160V IF, closed.

3.1.3.2 If powered from Emergency Transformer, Breaker EE-CB-4160F(1FS), EMERGENCY TRANSFORMER FEED 4160V 1F, closed.

Examination Outline Cross-Reference	Level	RO
295018 (APE 18) Partial or Complete Loss of CCW / 8 Knowledge of the reasons for the following responses as they apply to PARTIAL OR COMPLETE LOSS OF COMPONENT COOLING WATER: AK3.06 Increasing cooling water flow to heat exchangers	Tier#	1
	Group#	1
	K/A #	295018 AK3.06
	Rating	3.3
	Revision	0
Revision Statement:		

Question 46

Procedures 2.2.71 [Service Water System] and 2.2.65.1 [REC Operations] require raising Service Water flow through the in-service REC heat exchanger for a specific condition.

(1) Which one of the following is the specific condition for which Service Water flow through the in-service REC heat exchanger is required to be raised?

AND

(2) According to procedure 2.2.65.1 [REC Operations], what operating restriction applies with respect to SW to prevent exceeding REC heat exchanger design limits?

A. (1) Low REC system flow
(2) Do NOT exceed 6000 gpm

B. (1) Low REC system flow
(2) Do NOT exceed 17 psid across the heat exchanger divider plate

C. (1) Elevated river temperature
(2) Do NOT exceed 6000 gpm

D. (1) Elevated river temperature
(2) Do NOT exceed 17 psid across the heat exchanger divider plate

Answer: C

Explanation:
There are two REC heat exchangers. Normally, one HX is in service at 100% power. REC heat exchangers are cooled by Service Water via a motor operated SW valve on the outlet of each HX in series with an automatically or manually controlled temperature control valve. REC supply temperature is normally maintained ~75°F. Procedure 2.2.71 Precaution and Limitation 2.2 states at river temperatures approaching 95°F, maintain REC HX outlet temperature below 98°F per Procedure

2.2.65.1. Procedure 2.2.65.1 section 6 directs raising service water flow through the REC HX when river temperature is above 65°F, and section 17 directs raising service water flow through the REC HX.

REC heat exchanger is a shell and tube type HX. Procedure 2.2.65.1 Cautions at steps 17.1.1 and 19.3 state SW flow through REC HXs > 6000 gpm may result in exceeding HX design limitations.

Distracters:
Answer A part 1 is plausible because a reduction in REC flow will result in decreased cooling to REC loads. Raising SW flow to the in-service HX would mitigate that condition. It is wrong because the mitigation strategy for low REC flow is starting additional REC pumps or throttling open the associated REC HX REC outlet valve, not raising SW flow. A reduction in REC flow would actually result in SW flow being reduced automatically by its temperature control valve due to a reduction in REC HX outlet temperature. Part 2 is correct.

Answer B part 1 is plausible and wrong for the reason stated for distractor A. Part 2 is plausible because it represents a limit related to RHRSW flow rate through an RHR heat exchanger IAW procedure 2.2.70 [RHR Service Water Booster Pump System]. RHR heat exchanger is also a shell and tube type HX. It is wrong because it is the limit for RHR HX SW divider plate differential pressure, not REC heat exchanger.

Answer D part 1 is correct. Part 2 is plausible and wrong for the reason stated for distractor B.

Technical References: Procedures 5.2REC [Loss of REC](Rev 18), 2.2.65.1 [REC Operations](Rev 78), 2.2.70 [RHR Service Water Booster Pump System](Rev 90)

References to be provided to applicants during exam: none

Learning Objective: COR002-19-02 Obj LO-5d, Briefly describe the following concepts as they apply to REC: Heat Exchanger Operation during normal, accident and transient operation

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	

10CFR Part 55 Content:	55.41(b)(4)
Level of Difficulty:	3

SRO Only Justification:	N/A
PSA Applicability:	
Top 10 Risk Significant System – Service Water	

4.7 IF REC is supplying critical loops and M-1/A-3, REC SURGE TANK LOW LEVEL, alarming, THEN perform following:

NOTE – Step 4.7.1 requires Operator to obtain a 10' ladder to reach DW-470.

4.7.1 IF REC surge tank level control valve failed closed, THEN open DW-470, REC SURGE TANK LCV-488 BYPASS, as required (R-976-W above REC surge tank).

NOTE – Cooling to the critical loops is required to be restored within 1 hour to ensure postulated temperature limits are maintained. Ⓟ[5]

4.8 IF critical loop(s) cooling is required and REC pumps are unable to supply cooling, THEN perform following prior to CSCS Quad temperatures exceeding 150°F:

4.8.1 If available, initiate service water backup per Attachment 6 (Page 12).

4.8.2 IF CSCS Quad cooling cannot be established, THEN enter Procedure 2.4HVAC.

4.9 IF SW cooling lost to single REC HX, THEN perform following:

4.9.1 If available, place standby REC HX in service per Attachment 3 (Page 7).

4.9.2 Monitor REC HX outlet temperature from REC-TI-452, REC HEADER TEMPERATURE, or PMIS Point M136 if REC-TI-452 not available.

4.9.3 IF REC HX outlet temperature approaches 98°F, THEN reduce REC heat load with one or both of following:

4.9.3.1 Reduce reactor power, as necessary, to maintain REC HX outlet temperature to ≤ 98°F per Procedure 2.1.10.

4.9.3.2 Rapidly remove RWCU from service per Procedure 2.2.66.

4.9.4 IF at any time REC HX outlet temperature cannot be maintained ≤ 98°F, THEN shut down per Procedure 2.1.4.

4.10 IF REC temperature indication is not available, REC non-critical loads are in service and a PCIS Group 2 isolation due to a primary coolant leak is present, THEN perform one of following:

4.10.1 Maintain SW flow through REC HX A(B) ≥ 3500 gpm.

4.10.2 Isolate non-critical REC headers.

4.11 IF REC to Non-Regen HX isolated, THEN rapidly remove RWCU from service per Procedure 2.2.66.

4.12 IF REC cooling to FPC HXs lost, THEN enter Procedure 2.4FPC.

4.2.2 IF REC activity levels > 14 cps, as read on RMP-RR-353, REC RAD MONITOR RECORDER, THEN perform following:

NOTE – Chemistry may delay sampling 24 to 48 hours to ensure a representative sample obtained.

4.2.2.1 Contact Chemistry to estimate REC in-leakage by sampling.

4.2.2.2 WHEN sample results available, THEN apply correction in Procedure 6.LOG.601 or 6.LOG.602 for Chemistry estimated in-leakage.

4.2.2.3 Determine sampling frequency based on input from Chemistry and Engineering.

4.2.2.4 IF any activity occurs which has potential to transfer water from REC System to TEC System, THEN contact Chemistry to determine if a TEC System sample warranted.

4.2.3 IF Chemistry REC sample results indicate > 1.0E-5 µCi/ml, THEN contact Radiation Protection to implement appropriate radiation protection controls on REC System.

4.2.4 WHEN REC activity levels < 10 cps, as read on RMP-RR-353, REC RAD MONITOR RECORDER, THEN sampling may be discontinued.

5. NORMAL REC SYSTEM OPERATION - RIVER TEMPERATURE 65°F OR BELOW

5.1 Operate REC System pumps (normally three pumps) to maintain system alarms clear.

NOTE – When starting REC pump, it is normal for associated pump low pressure alarm to come in and immediately clear.

5.1.1 Prior to performing evolution that will lower REC pressure, IF pressure indicated on REC-PI-452, REC HEADER PRESSURE (Panel M), below following pressures, THEN start fourth REC pump.

5.1.1.1 69 psig with critical loops unisolated.

5.1.1.2 74 psig with critical loops isolated.

5.1.2 IF fourth REC pump started per Step 5.1.1, THEN secure pump started when evolution that will lower REC pressure completed.

5.2 Maintain SW flow through REC HXs ≤ 3500 gpm per HX unless performing Section 17 or 19.

CNS OPERATIONS MANUAL SYSTEM OPERATING PROCEDURE 2.2.65.1 REC OPERATIONS	USE: CONTINUOUS QUALITY: QAPD RELATED EFFECTIVE: 3/13/19 APPROVAL: ITR-RDM OWNER: OSG SUPV DEPARTMENT: OPS

REVISION VERIFICATION:
(initial use + every 7 days)

REV.	DATE	CHANGES
77	11/28/18	Enhanced guidance for low pressure operations.
78	3/13/19	Added guidance to start fourth REC pump if necessary. Enhanced temperature control guidance.

16.3.14.3 Open DW-145, REC HEAT EXCHANGER SUPPLY (R-931-N west end of HX B).

16.3.14.4 Throttle open SW-127, SW/DW CROSSTIE REC HX B FLUSH (R-931-N REC HX area), until air free water flows from SW-128, REC HX A OUTLET VENT (R-931-N REC HX area), and SW-129, REC HX B INLET VENT (R-931-N REC HX area).

16.3.14.5 Close SW-127.

16.3.14.6 Close SW-128.

16.3.14.7 Close SW-129.

16.3.14.8 Close DW-145.

17. OPERATION AT ELEVATED RIVER TEMPERATURES

17.1 Maintain REC HX outlet temperature ≤ 98°F read from REC-TI-452 (or PMIS Point M136 if REC-TI-452 not available) by performing following:

CAUTION – SW flow through REC HXs > 6000 gpm may result in exceeding HX design limitations.

17.1.1 Ensure plant conditions acceptable prior to raising SW flow to either REC HX > 3500 gpm.

17.1.2 Raise SW flow through REC HX A > 3500 gpm by performing one of following:

NOTE 1 – If red LED next to % symbol illuminated, controller in MANUAL. Indicator range is 0.0 (full closed) to -100 (full open).

NOTE 2 – If red LED next to % symbol not illuminated, controller in AUTO. Indicator range is 40 to 160.

17.1.2.1 IF REC-TIC-451A, SW TO REC HX A (R-931-NE), in AUTO, THEN locally adjust temperature setpoint using up/down arrows.

17.1.2.2 IF REC-TIC-451A, SW TO REC HX A (R-931-NE), in MANUAL, THEN locally adjust percent output setpoint using up/down arrows.

17.1.2.3 IF SW-TCV-451A, REC HX A SW OUTLET TEMPERATURE CONTROL, cannot be throttled to control SW flow through REC HX A, THEN perform following:

a. Throttle SW-MO-650, REC HX A SERVICE WATER OUTLET, until SW flow through REC HX A lowers.

b. Place SW-TCV-451A switch to OPEN.

c. Throttle SW-MO-650 to obtain desired temperature.

CNS OPERATIONS MANUAL EMERGENCY PROCEDURE 5.2REC LOSS OF REC	USE: CONTINUOUS QUALITY: QAPD RELATED EFFECTIVE: 6/21/17 APPROVAL: ITR-RDM OWNER: OSG SUPV DEPARTMENT: OPS

Scram Actions

1. ENTRY CONDITIONS

1.1 REC HEADER PRESSURE ≤ 62 psig.

1.2 Rising temperatures on equipment cooled by REC.

1.3 Multiple low REC flow alarms on VBD-M.

1.4 Multiple REC pump alarms on VBD-M.

2. AUTOMATIC ACTIONS

2.1 REC pumps in STANDBY starts 20 seconds after 4160V Bus 1F or 1G re-energized by emergency power.

2.2 Following valves close when REC header pressure drops below specified pressure, plus a 40 second time delay:

2.2.1 REC-MO-712, HX A OUTLET (61 psig).

2.2.2 REC-MO-700, NON-CRITICAL HEADER SUPPLY (61 psig).

2.2.3 REC-MO-702, DRYWELL SUPPLY ISOLATION (61 psig, if control switch in AUTO).

2.2.4 REC-MO-1329, AUGMENTED RADWASTE SUPPLY (61 psig).

2.2.5 REC-MO-713, HX B OUTLET (61 psig).

Scram Actions

3. IMMEDIATE OPERATOR ACTIONS

3.1 IF REC HEADER PRESSURE ≤ 62 psig, THEN start available REC pumps.

3.2 IF REC HEADER PRESSURE <u>not</u> restored, THEN close following valves:

3.2.1 REC-AO-710, RWCU NON-REGEN HX INLET.

3.2.2 REC-MO-1329, AUGMENTED RADWASTE SUPPLY.

4. SUBSEQUENT OPERATOR ACTIONS

4.1 Record current time and date. Time/Date: ________ / ________

1. PURPOSE

   1.1 Operate Residual Heat Removal (RHR) Service Water Booster Pump (SWBP) System.

2. PRECAUTIONS AND LIMITATIONS

   2.1 SWBP run out may occur from operation in excess of 136 amps.

   2.2 SWBP running current in excess of 136 amps prohibited.

   2.3 SWBP overheating and damage may occur with subsystem flow less than 2500 gpm.

   2.4 SWBP operation with subsystem flow less than 2500 gpm prohibited.

   2.5 RHR HX SW divider plate differential pressure in excess of 17.0 psid prohibited.Ⓟ[3]

   2.6 Simultaneous operation of both SWBPs in subsystem greater than 1 minute prohibited, except when required by EOPs.Ⓒ[1]

   2.7 SWBP oil levels may take up to 24 hours after shutdown to return to pre-start conditions.

   2.8 Oil leakage of one drop per minute can be allowed and still meet the 30-day mission time for SWBPs, refer to EC 6040480.

   2.9 SWBP operation limited to less than or equal to 24 hours without stuffing box gland water flow.

Examination Outline Cross-Reference	Level	RO
286000 (SF8 FPS) Fire Protection Knowledge of electrical power supplies to the following: K2.02 Pumps	Tier#	2
	Group#	2
	K/A #	286000 K2.02
	Rating	2.9
	Revision	0
Revision Statement:		

Question 47

What is the power supply to Fire Pump C?

480V Bus…

A. 1B

B. 1E

C. 1F

D. 1G

Answer: B
Explanation: Electric Fire pump (1C) located in the Service Water Pump Room, in the intake structure, can supply the fire protection water system. The pump takes suction from the Missouri River and delivers this water, via a double basket strainer, to the fire system main piping loop. This pump starts automatically at 68 psig and is rated at 2000 gpm. It is powered from 480V AC Bus 1E. This is the last fire pump to start on lowering pressure as river water is not as desirable as clean water.
Distracters: Answer A is plausible because it reflects another 480V bus that supplies other pumps, such as TEC Pump 1C. It is wrong because 480V Bus 1E supplies Fire Pump C. Answer C is plausible because it reflects another 480V bus that supplies other pumps, such as CRD Pump 1A. Also, 480V Bus 1F is safety-related, and an examinee may believe Fire Pump C is supplied by a safety-related bus, since it is required by Appendix R. It is wrong for the same reason given for distractor A. Answer D is plausible because it reflects another 480V bus that supplies other pumps, such as CRD Pump 1B. Also, 480V Bus 1G is safety-related, and an examinee may

believe Fire Pump C is supplied by a safety-related bus, since it is required by Appendix R. It is wrong for the same reason given for distractor A.		
Technical References: Lesson Plan COR001-05-01 [Fire Protection System](Rev 36), procedure 2.2A_480.IS [480 VAC Intake Structure Building Breaker Checklist](Rev 17)		
References to be provided to applicants during exam: none		
Learning Objective: COR001-05-01 LO Obj 6b, State the electrical power supplies to the following: Electric Fire Pumps "C" & "E"		
Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(4)	
Level of Difficulty:	2	
SRO Only Justification:	N/A	
PSA Applicability:		
N/A		

Lesson Number: COR001-05-01	Revision: 36

c. An emergency lever on the controller.

SO-11
LO-08b

4. Once started, either manually or automatically, Electric Fire pump (1E) must be manually stopped. This is accomplished by taking the three-position switch on the Control Room's Fire Alarm Panel to PULL-TO-LOCK position or by the local controller STOP push button, in the pump house.

SO-07a, 08,23f
LO-08f, l; 09c; 11a
LO-08b, SO-21b

5. Electric Fire pump (1C) located in the Service Water Pump Room, in the intake structure, can supply the fire protection water system. The pump takes suction from the Missouri River and delivers this water, via a double basket strainer, to the fire system main piping loop. This pump starts automatically at 68 psig and is rated at 2000 gpm. It is powered from 480V AC 1E. This is the last fire pump to start on lowering pressure as river water is not as desirable as clean water.

The pump may be manually started by either:

a. A switch on the Fire Alarm Panel in the Control Room.

b. A start push button on the local pump controller

c. An emergency lever on the controller.

LO-08b,SO-11

Once started, either manually or automatically, Electric Fire pump (1C) must be manually stopped. This is accomplished by taking the three position switch on the Control Room's Fire Alarm Panel to its PULL-TO-LOCK position or by the local control STOP push button, in the pump room.

Fig 3

D. Diesel Engine Driven Fire Pump

LO-01e; 12a
SO-02d
LO-09l, m, o; 13e

1. The diesel driven fire pump acts as a backup to Electric Fire Pump 1E. If the system pressure was to fall and pump 1E was not able to maintain pressure

480V SWITCHGEAR 1E (IS-903) FED FROM 4160V SWITCHGEAR 1E

BREAKER	DESCRIPTION	NORMAL POSITION	PERFORMED BY	VERIFIED BY	COMMENTS
EE-CB-480E (FP-C) BREAKER 1A	C FIRE PUMP	CLOSED			
EE-CB-480E (SCNP-B) BREAKER 1B	SCREEN WASH PUMP 1B	RACKED IN			
EE-CB-480E (MCC-Z) BREAKER 1C	MCC-Z FDR	CLOSED			
SPARE BREAKER 1D	SPARE	OPEN			
EE-CB-480E (SCNP-A) BREAKER 2D	SCREEN WASH PUMP 1A	RACKED IN			

Examination Outline Cross-Reference	**Level**	RO
295006 (APE 6) Scram / 1 Ability to operate and/or monitor the following as they apply to SCRAM: AA1.03 Reactor/turbine pressure regulating system	**Tier#**	1
	Group#	1
	K/A #	295006 AA1.03
	Rating	3.7
	Revision	0
Revision Statement:		

Question 48

A MANUAL scram is inserted with the plant at 25% power.

Which one of the following completes the statements below for this event?

When the anti-motoring turbine trip is received,

(1) DEH shifts to Mode ________ .

AND

(2) Bypass valves respond by _______ .

A. (1) 3
(2) throttling open to maintain the DEH pressure setpoint

B. (1) 3
(2) rapidly opening fully for 5 seconds, then throttle to maintain the DEH setpoint

C. (1) 1
(2) throttling open to maintain the DEH pressure setpoint

D. (1) 1
(2) rapidly opening fully for 5 seconds, then throttle to maintain the DEH setpoint

Answer: C

Explanation:
Upon a scram when the generator is on line, turbine governor valves throttle closed to maintain the DEH pressure setpoint as reactor power and steam production lower. As steam flow lowers, a turbine generator anti-motoring trip occurs when HP turbine dp goes below 30 psid after a 25 second time delay. At this point, turbine generator load is nearing zero, below 106 MWe. Upon a turbine trip below 106 MWe, bypass valves throttle open to maintain the DEH setpoint,

Distracters:
Answer A part 1 plausible because DEH is in Mode 4 at 25% power. DEH transitions from Mode 3 to Mode 4 when the generator is placed on line. An examinee may believe that DEH shifts to the previous mode, Mode 3, when the generator trips. Also, the reactor mode shifts to Mode 3 upon a scram. It is wrong because when the turbine trips due to low HP turbine dp, DEH shifts to Mode 1 (turbine not latched). Part 2 is correct

Answer B part 1 is plausible and wrong for the same reason as given for distractor A. Part 2 is plausible because generator load is initially above 106 MWe at 25% power, and for a turbine trip above 106 MWe, the bypass valve actuator dump valves open, causing the bypass valves to fully open rapidly for 5 seconds. It is wrong because the anti-motoring trip setpoint corresponds to a generator load below 106 MWe, so bypass valves throttle open only so far as required to maintain the DEH pressure setpoint.

Answer D part 1 is correct. Part 2 is plausible and wrong for the reason stated for distractor B.

Technical References: Lesson plan COR002-09-02 [Digital Electro-Hydraulic Control](Rev 20)

References to be provided to applicants during exam: none

Learning Objective: COR002-09-02 Obj LO-8o, Predict the consequences a malfunction of the following would have on DEH Control system: Reactor Scram

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(5)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	

PSA Applicability:
N/A

Lesson Number: COR002-09-02	Revision: 20

LO-11,12 7. The system operates in one of four modes.

LO-08p,15a a. DEH MODE 1
The DEH control system is in the REACTOR START mode when the turbine is "tripped" (not "latched" - all valves closed) and the reactor plant is being warmed up and pressurized. During this mode the DEH system is used to position the turbine Bypass Valves (BPVs) to control reactor pressure/temperature, once condenser vacuum is above > 7 " Hg, during the reactor heatup by dumping steam to the condenser.

LO-15b b. DEH MODE 2
The TURBINE START mode is entered when the turbine is "latched" by depressing the LATCH button. This causes the Intercept Valves (IVs) and the Stop Valves (SVs) to open. BPVs continue to control pressure. The governor valves (GVs) remain closed until positioned by the operator to begin rolling the turbine to warm up and bring it up to synchronous speed (1800 RPM) in preparation for placing the generator on the grid. The BPVs continue to control pressure.

LO-15c c. DEH MODE 3
The LOAD CONTROL mode is entered when the first of either generator output breakers is closed (3310 or 3312). DEH is normally in this mode for only a brief period of time as generator output is automatically ramped up until the turbine BPVs close. Turbine LOAD DEMAND is automatically ramped to 200 MWe at 300 MWe/min when the generator output breaker is closed. The turbine BPVs which are controlling pressure, automatically ramp closed to maintain throttle pressure at the requested press set point as GVs open and turbine load (and steam flow) increases. When turbine load demand (MWe demand) is increased to the point that throttle (reactor) pressure cannot support it, the throttle pressure demand signal becomes the controlling signal for the GVs and the system enters TURBINE FOLLOW REACTOR mode. This occurs at the same

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time that the turbine BPVs fully close.

LO-04e,m,15d

d. DEH MODE 4

The TURBINE FOLLOW REACTOR mode is the normal mode DEH is in while the turbine generator is in service. It is entered when the load demand signal (MWe demand) exceeds the throttle pressure demand signal. As was previously mentioned, entry into this mode is typically indicated by bypass valve closure, (although bypass valve closure does not cause this mode change). In the Turbine Follow Reactor mode of operation a turbine load increase is achieved by increasing reactor power which increases throttle pressure which causes the GVs to open further to accept the additional steam flow in order to control pressure. Simply stated, DEH is in a GV pressure control mode. If the LOAD DEMAND becomes limiting, DEH will shift back to LOAD CONTROL, the GVs will modulate at the prescribed load and the BPVs will modulate to control pressure. Normally, however, the LOAD DEMAND setpoint (MWe demand) is adjusted up and out of the way to prevent this from occurring.

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TABLE 1
Overspeed Protection Circuit (OPC) and Main Turbine Trips

OPC is enabled in Modes 2, 3, and 4. OPC actuation may be activated by 103% speed.

If turbine speed is ≥ 103%, the OPC solenoids are energized; this closes the governor and intercept valves immediately .OPC action is reset when the speed drops below 100% (1800 rpm).

The following trips are configured in the Trip Tricon:

a. Control Tricon Trip - A trip signal is sent to the Trip Tricon on a Control Tricon Trip. The Control Tricon trips are:

1. Overspeed - 1908 rpm (106%).
2. Loss of Speed Signal.
3. Fail to Detect Speed During Turbine Startup.
4. Trip Tricon Trip.

b. Bearing Oil Pressure Low Trip -≤ 6 psig.
c. Thrust Bearing Pressure High Trip - ≥ 77 psig.
d. Anti-motoring trip - HP Turb Diff press 30 psid
d. Stop Valve Emergency Trip Header Pressure Low Trip -≤ 500 psig.
e. Condenser Pressure High Trip - Calculated from a dynamic trip table based on pressure vs. megawatts.
f. TG 932 North Turbine Emergency Stop PB Trip - Generates a Trip Tricon trip if both pushbuttons are held in trip.
g. Trip Tricon Overspeed Trip - 1908 rpm (106%); may be set to an operated determined value for trip testing.

1. Defaults to 1908 rpm during a Trip Tricon power up.
2. During a turbine trip is reset to 1908 rpm.

h. Trip Tricon Loss of Speed Trip - Loss of all speed inputs to Trip Tricon.
i. Fail to Detect Speed During Turbine Startup Trip - Generated if all of following are true:

1. Turbine is latched.
2. Any two of the three speed signals measures below arming speed of 120 rpm.
3. Selected signal from Control Tricon reads over 45%; this indicates that Control Tricon is reading speed.

LO-03k

The following provides an overview of the trip function:

When any trip is active, the two interposing relays energize (each relay has a separate DO from the Tricon for redundancy) and close two parallel contacts, two from each relay, to energize the trip solenoids to open and depressurize the emergency trip header (solenoid valves energize open to depressurize the header and de-energize to close and pressurize the header).

Generator electrical trips (including reactor high water level trip, 86 lockout relays, and Anti-motoring) are tied directly to solenoid valves 20AST1 and 20 ET which energize and open on a trip signal

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to depressurize the stop valve emergency trip header. The electrical trip circuits from the main generator protective relays and others are not brought into the Trip or CONTROL TRICONs. However, the trip solenoid valves are energized from the CONTROL or TRIP TRICON.

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Tile/Location	Initiating Device/ Setpoint	Additional Functions
l. TG MOTORING, B-1/C-3	Relay operation caused by 30 psid ↓ HP turbine inlet pressure to HP turbine exhaust pressure while tied to grid TG-REL-2XAM operation caused by (MS-DPT-1, 2, 3, 4). and Relay 27X picked up (voltage applied to main generator) and Relay 52X picked up (PCB 3310 and/or PCB 3312 are closed) voted middle of four indicators selected	Turbine trips after 25 second time delay
m. TG EMERGENCY BRG OIL PUMP RUNNING, B-1/C-4	DC emergency oil pump starts	Check pressure on one of following to verify alarm is valid: On TRANSMITTER SELECT 1 screen, BEARING OIL PRESSURE control on LOGT-PT-209A (B or C), BEARING OIL PRESSURE, value column. LOGT-PI-86, BRG OIL PRESSURE (PANEL B).
n. TG TRIP CIRCUIT SUPERVISION, B-1/C-5	Relay operation caused by loss of 125 VDC control power to: 1. (3511) TG TRIP CIRCUIT POWER FAILURE 27RTG. 2. (3512) TG TRIP CIRCUIT POWER FAILURE 30ASTS	If 125 VDC Panel BB2 or 125 VDC Distribution Panel B is de-energized, take action per Procedure 5.3DC125 as dictated by plant conditions.

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b. Bypass Valve Operation

Each turbine bypass valve actuator is equipped with a bypass reset solenoid valve on their respective trip headers. These solenoid valves are de-energized and open when turbine load is above (setpoint between 106 MWE and 116 MWE).

On a turbine trip, the bypass valve actuator dump valves will unseat, directing HP fluid pressure to the underside of the bypass valve actuator piston, bypassing the servo-valve. This causes the turbine bypass valves to rapidly open. After the trip occurs and power has decreased to below (setpoint between 106 MWE and 116 MWE), a 3-5 second time delay elapses and the bypass reset solenoid valves will energize and close. This allows the servo-valve to be used to operate the bypass valves to control reactor pressure based on the DEH system control signals.

If the bypass valves were in AUTO prior to the turbine trip, they will control reactor pressure based on the pressure setpoint.

If the bypass valves were in MANUAL prior to the turbine trip, they will be positioned to the manual demand signal from the bypass valve controller (i.e.; If the manual controller demand was at 0, the bypass valves will close and stay closed till the operator adjusts the manual position).

If in the event a turbine trip occurs when power is already below (setpoint between 106 MWE to 116 MWE), the turbine bypass valves will continue to operate based on bypass valve demand signal (AUTO or MANUAL).

LO-08i,o 2. Generator Trip/Reactor Scram

A Main Generator trip or reactor scram will result in a trip of the Main Turbine (either directly or indirectly), producing the same response as discussed for a turbine trip. A generator trip that does not cause a turbine trip, (i.e. normal shutdown)

Lesson Number: COR001-14-01	Revision: 31

Fig. 11 2. Interlocks and Trips
LO-03a,e
LO-15b; 16d; 21a

Interlock/Trip	Initiating Device/ Setpoint	Additional Functions
a. Main Turbine Auto Trips		
1) Condenser Low Vacuum	Main condenser low vacuum dynamically calculated based on absolute pressure and megawatts.	Indicates a possible heat sink loss; or a rupture of the atmospheric relief diaphragms.
2) Low Bearing Oil Pressure	6 psig decreasing	Turbine trips on possible failure of lube oil system; continued operation would probably result in wiped bearings and possible damage to the turbine.
3) Overspeed	Electrical 106%	Turbine trips before overspeed condition results in rotor damage.
4) Thrust Bear Wear	77 psig increasing	Indicates incipient bearing failure.
5) Generator Motoring	30 psid decreasing on HP turbine inlet to exhaust differential press.	Turbine trips following 25 sec. time delay.
6) Reactor High Water Level	+54"	To prevent moisture carryover from the reactor into the turbine.
7) Main Generator lockout relays	Various (Refer to Main Generator text)	The trip on exciter failure prevents damage to the Main Generator field windings from excessive temperatures.

Examination Outline Cross-Reference	Level	RO
295026 (EPE 3) Suppression Pool High Water Temperature / 5 Knowledge of the operational implications of the following concepts as they apply to SUPPRESSION POOL HIGH WATER TEMPERATURE: EK1.02 Steam condensation	Tier#	1
	Group#	1
	K/A #	295026 EK1.02
	Rating	3.5
	Revision	1
Revision Statement: Rev 1 - Replaced part 1 distractor per NRC comment that part 1 distractor was borderline LOD=1 during “free review” using distractor from 12/2015 ILT NRC Q#13. Also replaced containment “failure” with containment “over-pressurization” in part 1 correct answer to make more distinctive from revised part 1 distractor.		

Question 49

An ATWS is in progress.

HPCI is in service for level control.

Suppression Pool temperature is rising.

(1) What is the principal operational concern if Suppression Pool temperature approaches the Heat Capacity Temperature Limit (HCTL)?

AND

(2) IAW EOP-3A, Emergency Depressurization is required when Suppression Pool temperature cannot be ___________ within HCTL.

A. (1) Exceeding the Torus design temperature
(2) maintained

B. (1) Exceeding the Torus design temperature
(2) restored and maintained

C. (1) Containment over-pressurization due to inability of the Suppression Pool to absorb all energy from a blowdown
(2) maintained

D. (1) Containment over-pressurization due to inability of the Suppression Pool to absorb all energy from a blowdown
(2) restored and maintained

Answer: C

Explanation:
Operation in the safe region of the Heat Capacity Temperature Limit (HCTL) graph ensures there is sufficient heat capacity in the suppression pool to absorb energy and condense steam from SRV discharge and steam discharged through the drywell downcomers.

HCTL is the highest suppression pool temperature from which emergency RPV depressurization will not raise:

- Suppression chamber temperature above the maximum temperature capability of the suppression chamber, or
- Suppression chamber pressure above Primary Containment Pressure Limit,

while the rate of energy transfer from the RPV to the containment is greater than the capacity of the containment vent.

Exceeding HCTL could result in exceeding design limits during a blowdown, which could result in containment failure.

IAW EOP-3A step SP/T-5, emergency depressurization is required before HCTL is exceeded in order to reduce the energy within the RPV before reaching plant conditions for which the pressure suppression system may not be able to safely accommodate an SRV opening or condense steam discharged through the downcomer vents. “Cannot be maintained” requires the action to be taken as soon as it is determined HCTL will be exceeded or as soon as it exceeded. This is in contrast to “restored and maintained”, which allows a limit to be exceeded without having to take the associated action, if there is reason to believe the parameter can otherwise be restored to within the limit.

Distracters:
Answer A part 1 is plausible because the torus design temperature is sometimes confused with the temperature capability of the torus, which is variable based upon RPV pressure, Torus level, and initial Torus temperature. This answer is wrong because HCTL is concerned with ensuring the heat absorption capability of the SP from SRV and DW downcomer vent discharges is sufficient for adequate steam condensation to prevent overpressurizing containment above PCPL. Part 2 is correct.

Answer B part 1 is plausible and wrong for the reasons stated for distractor A. Part 2 is plausible because other EOP steps, such as EOP-3A step DW/T-5, require emergency depressurization when a parameter cannot be restored and maintained within the limit, allowing attempts to restore the parameter without inducing the serious transient of a blowdown. It is wrong because EOP-3A step SP/T-5 requires emergency depressurization when operation cannot be maintained within the limit (HCTL), and no allowance for restoration within limits is provided.

Answer D part 1 is correct. Part 2 is plausible and wrong for the reasons stated for distractor B.		
Technical References: EOP-3A [Primary Containment Control](Rev 18), AMP-TBD00 [PSTGs](Rev 10)		
References to be provided to applicants during exam: none		
Learning Objective: INT008-06-13 EO-4c, State the basis for primary containment control actions as they apply to the following: Graphs referenced on Flowchart 3A; INT008-08-16 EO-2, For each graph used in the flowcharts, identify the action(s) required if the parameters associated indicate operation in the restricted or prohibited area.		
Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(10)	
Level of Difficulty:	2	
SRO Only Justification:	N/A	
PSA Applicability:		
N/A		

11. PSTG CONTINGENCY #2 EMERGENCY RPV DEPRESSURIZATION

Overview

The actions specified in Contingency #2 rapidly depressurize the RPV and maintain the RPV in a depressurized state. The steps of this contingency may be required to:

- Establish or maintain adequate core cooling.
- Terminate or minimize the discharge of reactor coolant from unisolable primary system breaks.
- Reduce the energy within the RPV before reaching plant conditions for which the pressure suppression system may not be able to safely accommodate an SRV opening or condense steam discharged through the downcomers.
- Minimize radioactivity release from the RPV to the primary containment and secondary containment, or to areas external to the primary containment and secondary containment.

The RPV is considered "depressurized" when the RPV to suppression chamber differential pressure is less than the Decay Heat Removal Pressure (DHRP). The DHRP is used as the basis for the depressurized state since, (a) the DHRP, by definition, is equal to or greater than the lowest pressure at which an SRV will fully open and remain fully open when its control switch is placed in the "open" position, and (b) below this differential, the rate of energy addition to the primary containment will be within the capacity of the primary containment vent path. Refer to Section 18 of this appendix for a detailed discussion of the DHRP.

Opening SRVs Is the preferred method for performing emergency RPV depressurization. Alternative methods are identified for use if SRVs are not available. In addition, if the main condenser is available, the override before Step RC/P-1 permits rapid RPV depressurization through the main turbine bypass valves in anticipation of an emergency depressurization requirement. (Refer to the discussion of the override before Step RC/P-1 in Section 6 of this appendix.)

Under circumstances requiring emergency RPV depressurization, it is generally desirable to fully depressurize the RPV and cool down the plant to cold shutdown

Table B-11-1

Conditions Requiring Emergency RPV Depressurization

Condition	Step
1. When suppression pool temperature and RPV pressure cannot be maintained below the Heat Capacity Temperature Limit.	SP/T-4
2. When drywell temperature cannot be restored and maintained below the maximum temperature at which ADS is qualified.	DW/T-3
3. When suppression chamber pressure cannot be maintained below the Pressure Suppression Pressure.	PC/P-2
4. If suppression pool water level cannot be maintained above the elevation of the downcomer openings.	SP/L-2.1
5. If suppression pool water level and RPV pressure cannot be restored and maintained below the SRV Tail Pipe Level Limit.	SP/L-3.1
6. When the temperature in more than one secondary containment area exceeds the respective maximum safe operating temperature and a primary system is discharging into a secondary containment area.	SC/T-4.2
7. When the radiation level in more than one secondary containment area exceeds the respective maximum safe operating radiation level and a primary system is discharging into a secondary containment area.	SC/R-2.2

18.6 Heat Capacity Temperature Limit

The Heat Capacity Temperature Limit (HCTL) is the highest suppression pool temperature from which emergency RPV depressurization will not raise:

- Suppression chamber temperature above the maximum temperature capability of the suppression chamber, or
- Suppression chamber pressure above Primary Containment Pressure Limit,

while the rate of energy transfer from the RPV to the containment is greater than the capacity of the containment vent.

The HCTL is a function of RPV pressure and suppression pool water level. It is utilized to preclude failure of the containment and equipment in the containment necessary for the safe shutdown of the plant.

The derivation of the HCTL is shown graphically in Figure B-18-7. HCTL curves are defined for selected suppression pool water levels between the elevation of the downcomer openings, and the Maximum Pressure Suppression Primary Containment Water Level. Each curve comprises two lines: a and b. When RPV pressure is at or below the Decay Heat Removal Pressure, the rate of energy transfer from the RPV to the containment (with the Minimum Number of SRVs Required for Emergency Depressurization open) is, by definition of the Decay Heat Removal Pressure, within the capacity of the containment vent. The HCTL is therefore vertical at the Decay Heat Removal Pressure. The intersection of Lines a and b (Point A) is defined by this pressure and the lesser of:

- The maximum temperature capability of the suppression chamber, and
- The suppression chamber temperature at which suppression chamber pressure will be at Primary Containment Pressure Limit.

For RPV pressures above the Decay Heat Removal Pressure, the HCTL ensures that there is sufficient heat capacity in the suppression pool to sustain a blowdown. If a blowdown is initiated from any point on Line a, RPV pressure will drop below the Decay Heat Removal Pressure before suppression pool temperature rises above the ordinate of Point A. Since a blowdown from higher pressures adds more energy to the suppression pool, the HCTL decreases with increasing pressure. The abscissa of the high pressure endpoint is the lowest SRV lift setpoint.

18.24 Pressure Suppression Pressure

The Pressure Suppression Pressure (PSP) is the lesser of:

- The highest suppression chamber pressure which can occur without steam in the suppression chamber airspace. (This concern defines the CNS PSP).
- The highest suppression chamber pressure at which initiation of RPV depressurization will not result in exceeding Primary Containment Pressure Limit before RPV pressure drops to the Decay Heat Removal Pressure.
- The highest suppression chamber pressure which can be maintained without exceeding the suppression pool boundary design load if SRVs are opened.

The PSP is a function of primary containment water level.

The derivation of the PSP is shown graphically in Figure B-18-19.

Line 1 is the suppression pool water level corresponding to the elevation of the downcomer vent openings. If suppression pool water level is below this elevation, the RPV may not be kept in a pressurized state since steam discharged through the vents may not be condensed.

Line 2 is the maximum suppression pool water level corresponding to the Maximum Pressure Suppression Primary Containment Water Level (MPSPCWL) defined as the bottom of the ring header. Above this elevation, the pressure suppression capability of the primary containment may be insufficient to accommodate an RPV breach by core debris. The PSP is therefore vertical at this elevation.

Line 3 corresponds to the highest suppression chamber pressure which can occur without steam in the suppression chamber airspace. This pressure is determined by calculating the pressure that would exist as a function of suppression pool water level with all drywell noncondensibles purged to the suppression chamber and suppression pool temperature at the Heat Capacity Temperature Limit corresponding to the lowest SRV lift pressure. Higher suppression pool water levels result in higher pressures since the airspace volume is smaller.

Line 4 corresponds to the highest suppression chamber pressure from which an emergency depressurization will not raise suppression chamber pressure above Primary Containment Pressure Limit before RPV pressure drops to the Decay Heat Removal Pressure. This curve is calculated by subtracting the rise in suppression

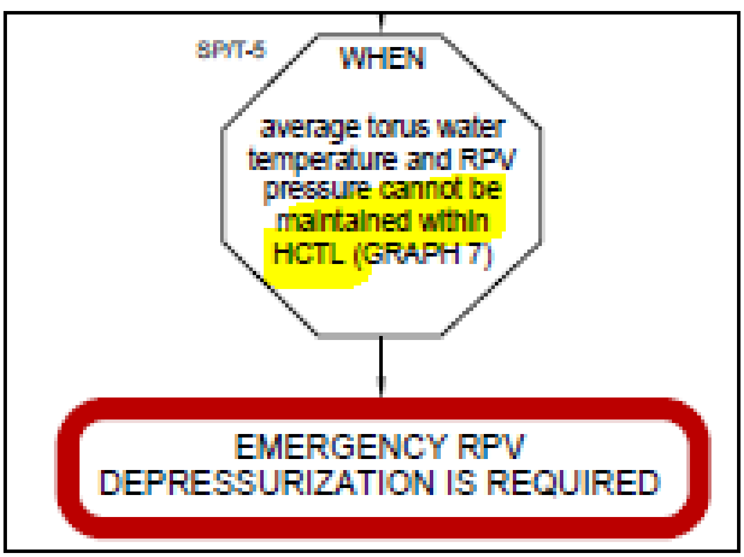
Can/Cannot be maintained above/below The value of an identified parameter is/is not able to be held within the specified limit. The determination requires an evaluation of system performance and availability in relation to parameter values and trends. An instruction prescribing action when a parameter cannot be maintained above or below a specified limit neither requires nor prohibits anticipatory action—depending upon plant conditions, the action may be taken as soon as it is determined that the limit will ultimately be exceeded, or delayed until the limit is actually reached. Once the parameter does exceed the limit, however, the action must be performed; it may not be delayed while attempts are made to restore the parameter to within the desired control band.

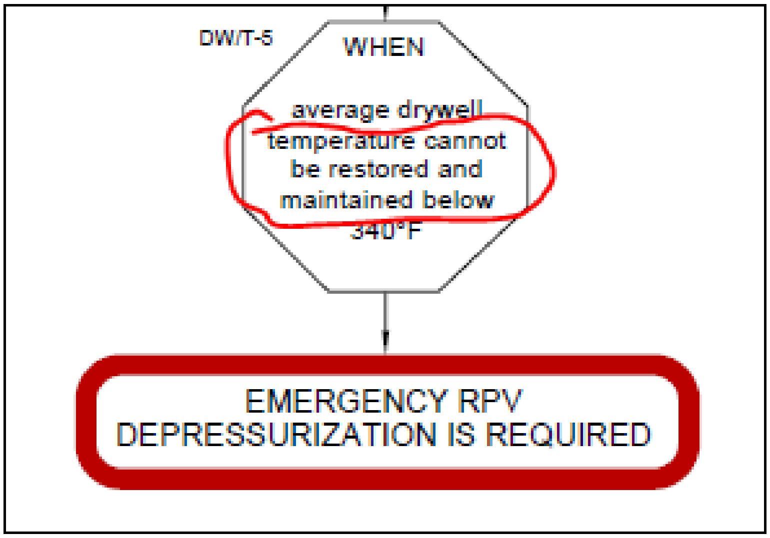
Can/Cannot be restored above/below The value of an identified parameter is/is not able to be brought within the specified limit. The determination requires an evaluation of system performance and availability in relation to parameter values and trends. An instruction prescribing action when a value cannot be restored and maintained above or below a specified limit does not require immediate action simply because the current value is outside the range, but does not permit extended operation beyond the limit; the action must be taken as soon as it is apparent that the specified range cannot be attained.

In the PSTGs/SATGs, the term "restored" is often used with the term "maintained" as in the phrase "can/cannot be restored and maintained above/below." Wide latitude for deciding when to take action is thus provided. The combination of terms permits taking action when the parameter approaches (but cannot be maintained) or when it is beyond (but can be restored to within) the specified limit. Interpretation of the combined terms is illustrated in the following example.

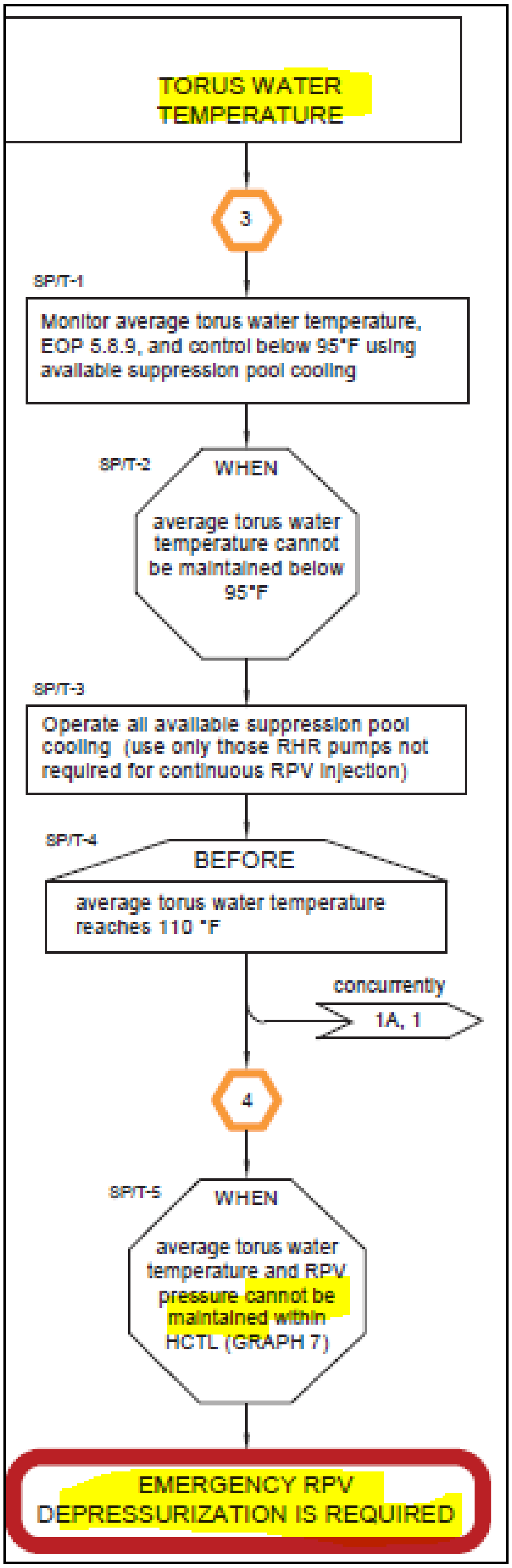
> EXAMPLE: RPV water level has dropped below the top of fuel and is decreasing to the Minimum Steam Cooling RPV Water Level (MSCRWL). Contingency #1 Step C1-4 requires emergency RPV depressurization when RPV water level cannot be restored and maintained above the MSCRWL. Flexibility in the timing of the decision is intended and evaluation of this hold point would then consider the following:

B - 3-5 Rev. 10

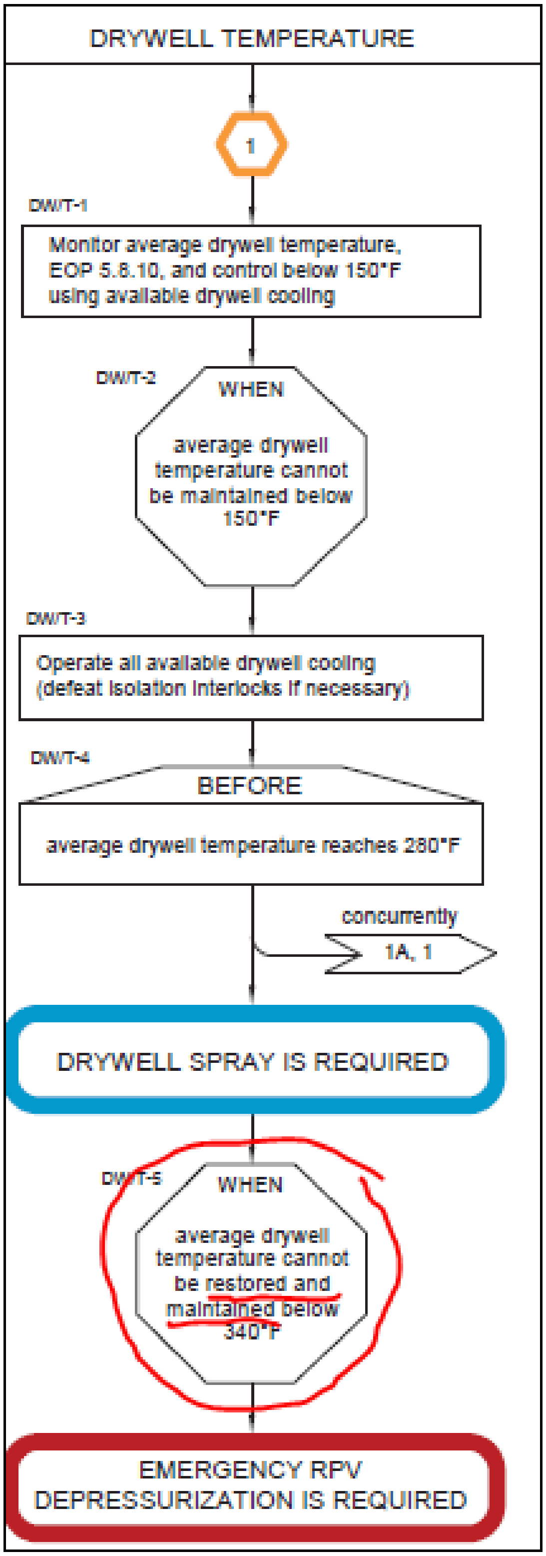



DW/T-5
WHEN
average drywell temperature cannot be restored and maintained below 340°F
EMERGENCY RPV DEPRESSURIZATION IS REQUIRED

From EOP-3A:


TORUS WATER TEMPERATURE
3
SP/T-1
Monitor average torus water temperature, EOP 5.8.9, and control below 95°F using available suppression pool cooling
SP/T-2
WHEN
average torus water temperature cannot be maintained below 95°F
SP/T-3
Operate all available suppression pool cooling (use only those RHR pumps not required for continuous RPV injection)
SP/T-4
BEFORE
average torus water temperature reaches 110 °F
concurrently
1A, 1
4
SP/T-5
WHEN
average torus water temperature and RPV pressure cannot be maintained within HCTL (GRAPH 7)
EMERGENCY RPV DEPRESSURIZATION IS REQUIRED

From EOP-3A:



DRYWELL TEMPERATURE
1
DW/T-1
Monitor average drywell temperature, EOP 5.8.10, and control below 150°F using available drywell cooling
DW/T-2
WHEN
average drywell temperature cannot be maintained below 150°F
DW/T-3
Operate all available drywell cooling (defeat isolation interlocks if necessary)
DW/T-4
BEFORE
average drywell temperature reaches 280°F
concurrently
1A, 1
DRYWELL SPRAY IS REQUIRED
DW/T-5
WHEN
average drywell temperature cannot be restored and maintained below 340°F
EMERGENCY RPV DEPRESSURIZATION IS REQUIRED

Examination Outline Cross-Reference	Level	RO
230000 (SF5 RHR SPS) RHR/LPCI: Torus/Suppression Pool Spray Mode Knowledge of the physical connections and/or cause-effect relationships between RHR/LPCI: TORUS/SUPPRESSION POOL SPRAY MODE and the following: K1.06 Keep fill system	Tier#	2
	Group#	2
	K/A #	230000 K1.06
	Rating	3.0
	Revision	0
Revision Statement:		

Question 50

The reactor scrammed 10 minutes ago from 100% power due to a steam leak in the drywell.

Containment Spray is required.

(1) What is the normal supply for Pressure Maintenance to RHR Loop B?

AND

(2) During operation of containment spray IAW Procedure 2.2.69.3 Section 12, why is the operator cautioned to maintain RHR pressure above Condensate Transfer System pressure?

A. (1) Condensate Pumps
(2) Prevent depleting CST

B. (1) Condensate Pumps
(2) Prevent raising Suppression Pool level

C. (1) Reactor Building Auxiliary Condensate Pump
(2) Prevent depleting CST

D. (1) Reactor Building Auxiliary Condensate Pump
(2) Prevent raising Suppression Pool level

Answer: B
Explanation: The Pressure Maintenance system prevents water hammer on pump starts and the possible pipe and valve damage that may result, and it prevents a pump runout condition from occurring while discharging to an empty pipe on a start.up. The

Condensate system supplies the Pressure Maintenance system during normal plant operations from the inlet to the Condensate Demineralizers. When the Condensate pumps are not operating, the Reactor Building auxiliary condensate pump (power supply MCC-N) will supply the Pressure Maintenance system. The Reactor Building auxiliary condensate pump takes a suction from the CST through a line which is also used for the Core Spray pumps' and RHR pumps' 1A and 1D alternate suction. With its control switch in AUTO (Panel 9-3 in the Control Room), PS-685 starts the Reactor Building aux. condensate pump when the pressure decreases to 50 psig. A scram on high DW pressure would not result in trip of CPs, so no low pressure condition occurs, and the RB Aux. Condensate Pump does not start. Therefore, CPs continue to supply Pressure Maintenance.

Procedure 2.2.69.3 caution at step 12.16.2 for placing Containment Spray in operation states Suppression Pool filling may occur if RHR Subsystem pressure less than Condensate Transfer System pressure.

Distracters:
Answer A part 1 is correct. Part 2 is plausible because CPs take suction from the hotwell, and the CST makes up to the hotwell. So, Pressure Maintenance flow would eventually deplete the CST. It is wrong because the concern for the Caution in procedure 2.2.69.3 is raising SP level if Pressure Maintenance pressure is higher than RHR pressure with Containment Spray valves open.

Answer C is plausible because the RB Aux. Condensate Pump will start and supply Pressure Maintenance to RHR if a low Pressure Maintenance supply pressure condition occurs. It is wrong because nothing in the stem would cause a loss of Pressure Maintenance system pressure, so CPs are still the supply. Part 2 is plausible because RB Aux. Condensate Pumps take a suction from the CST. It is wrong because the concern for the Caution in procedure 2.2.69.3 is raising SP level if Pressure Maintenance pressure is higher than RHR pressure with Containment Spray valves open.

Answer D part 1 is plausible and wrong for the reason given for distractor C. Part 2 is correct.

Technical References: Lesson Plan COR002-02-02 [Condensate and Feedwater](Rev 39), Lesson Plan COR002-23-02 [Ops Residual Heat Removal System](Rev 36), Procedure 2.2.69.3 [RHR Suppression Pool Cooling and Containment Spray](Rev 51)

References to be provided to applicants during exam: none

Learning Objective: COR002-23-02 Obj LO- 4c, Describe the interrelationship between the RHR system and the following: Pressure Maintenance system

Question Source:	Bank #	

(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(4),(7)	
Level of Difficulty:	2	
SRO Only Justification:	N/A	
PSA Applicability:		
Top 10 Risk Significant System - RHR		

Lesson Number: COR002-02-02	Revision Number: 39

2. Flowpaths

a. The Condensate system supplies the Pressure Maintenance system during normal plant operations from the inlet to the Condensate Demineralizers.

SO-06a

b. When the Condensate pumps are not operating, the Reactor Building auxiliary condensate pump (power supply MCC-N) will supply the Pressure Maintenance system. The Reactor Building auxiliary condensate pump takes a suction from the CST through a line which is also used for the Core Spray pumps' and RHR pumps' 1A and 1D alternate suction. With its control switch in AUTO (Panel 9-3 in the Control Room), PS-685 starts the Reactor Building aux. condensate pump when the pressure decreases to 50 psig.

When the pump is operating, PCV-684 is allowed to control Pressure Maintenance system pressure at 75 psig by recirculating some water from the pump discharge to the CST. Once started, the Reactor Building auxiliary condensate pump must be shutdown manually.

c. The Pressure Maintenance supply to each Core Standby Cooling System (CSCS) have a pressure reducing station with the exception of the "A" RHR system. These pressure reducing stations were isolated and bypassed shortly after plant startup. The pressure control valves (PCV) were always full open due to the pressure setpoint used. This combined with back leakage thru the check valves caused damage to the PCVs when a CSCS pump started. The "A" RHR loop was not provided with one since it was cross-connected with "B" RHR loop. The RHR loops were split out when LPCI loop select logic was removed. A local pressure indicator is available, and an alarm in the Control Room, to warn the operators of a low pressure condition. An alarm indicates low pressure in the Pressure Maintenance supply line and a possible loss of fill in the associated discharge line. One exception is the A RHR system which has a pressure switch in the discharge line only. The associated alarm indicates a possible loss of fill in the discharge line. The Pressure Maintenance system supplies

12.10 IF following exist:
- RPV less than or equal to 300 psig.
- Injection not desired.

THEN **CLOSE** RHR-MO-27B, OUTBD INJECTION VLV.Ⓟ[2]

NOTE – Reactor Building high ambient temperature may cause Suppression Pool temperature to rise before lowering.

CAUTION – RHR pump damage may occur from minimum flow operation greater than 15 minutes.

12.11 **START** RHR Pump B or D.

12.12 **THROTTLE OPEN** RHR-MO-38A, TORUS SPRAY THROTTLE VLV, to maintain desired containment pressure.

NOTE – RHR-MO-16B, LOOP B MIN FLOW BYP VLV, remains open when RHR Subsystem A less than or equal to 2107 gpm.

12.13 IF Subsystem A flow greater than 2107 gpm, THEN **ENSURE** RHR-MO-16B closed.

12.14 **THROTTLE** RHR-MO-66B, HX BYPASS VLV, to obtain desired cooling rate.

12.15 **START** drywell spray as follows:

12.15.1 **OPEN** RHR-MO-31A, DRYWELL SPRAY INBD VLV.

12.15.2 **THROTTLE** RHR-MO-26A, DRYWELL SPRAY OUTBD THROTTLE VLV, to maintain desired containment pressure.

12.16 **PERFORM** one of following:

12.16.1 **CLOSE** following:

12.16.1.1 CM-296, LOOP A INJECTION LINE PRESSURE MAINTENANCE SHUTOFF (R-881-NW Quad).

12.16.1.2 CM-38, PCV-266 BYPASS (R-958-SW).

CAUTION – Suppression Pool filling may occur if RHR Subsystem pressure less than Condensate Transfer System pressure.

12.16.2 **MAINTAIN** RHR Subsystem B pressure greater than Condensate Transfer System pressure.

Lesson Number: COR002-23-02	Revision: 36

d. Each RHR pump 4160V breaker has anti-pump circuitry to prevent the breaker from cycling after an electrical trip. The breakers have auto-close signals (LPCI initiation) which must be interrupted to remove the anti-pump seal in logic. First, the condition that caused the electrical trip must be cleared. The anti-pump seal in logic can be interrupted by either operating the 4160V breaker shutter to the left and back to the right or taking the RHR pump control switch to STOP.

LO-03d,i, 04c

7. Check valves are located on the discharge of each pump in order to prevent back flow through an idle pump and to aid in maintaining that leg of piping filled with water. The discharge piping is maintained filled with water, up to the LPCI injection valves, by the Pressure Maintenance system for two reasons:

LO-05e

a. Prevents water hammer on pump starts and the possible pipe and valve damage that may result.

b. Prevents a pump runout condition from occurring while discharging to an empty pipe on a start up. (Refer to the Condensate and Feedwater text for further information on the Pressure Maintenance system.)

LO-13e

8. Minimum Flow Valves (RHR-MO-16(#) (**) (A and B)

The pump minimum flow valves, one in each loop, provide the necessary flow through the pump in order to prevent pump overheating. The RHR pump minimum flow control valves are normally open. However, when in Shutdown Cooling mode theses valves are closed and their breakers opened to prevent draining the RPV to the torus, which would result in a reactor low water level scram and isolation of shutdown cooling.

The RHR pumps can operate on minimum flow for at least 15 minutes and have shown by test to operate for up to one hour. For conservatism, pump operation on minimum flow should be limited to 10 minutes or less.

a. MO-16A(B) is a normally open valve, operated by a control switch on Panel 9-3 (16B *).

LO-05b, 15d

b. The valve closes when flow is greater than 2107 gpm for 3.5 seconds in the associated loop if MO-20 is not full open, or greater than 2107 gpm in either Loop A or B for 3.5 seconds if MO-20 is full open.

Examination Outline Cross-Reference	Level	RO
295025 (EPE 2) High Reactor Pressure / 3 Knowledge of the interrelations between HIGH REACTOR PRESSURE and the following: EK2.09 Reactor power	Tier#	1
	Group#	1
	K/A #	295025 EK2.09
	Rating	3.9
	Revision	0
Revision Statement:		

Question 51

Startup is in progress following a 1-day shutdown near the end of the current operating cycle.

- Reactor power is 20%
- Main generator is on line

DEH Pump B trips, and DEH Pump A will NOT start, resulting in a plant transient.

Which one of the following completes the statements below regarding effects of this transient?

Reactor power will initially _____(1)____.

EOP-1A entry ______(2)______ be required.

A. (1) rise
(2) will

B. (1) rise
(2) will NOT

C. (1) lower
(2) will

D. (1) lower
(2) will NOT

Answer: A
Explanation:

Loss of DEH pumps results in Turbine Control Valves closing, which causes reactor pressure to rise. Reactor power rises due to void collapse caused by the pressure rise.

When TCVs close, a scram signal is generated on TCV Fast Closure. This scram signal is bypassed when reactor power is below 29.5% power. Since DEH pumps are lost, Bypass valves are unable to control reactor pressure. Since the TCV Fast Closure scram is bypassed and Bypass valves are unavailable, reactor pressure rises to the scram setpoint, 1050 psig. Reactor pressure above 1050 psig is an entry condition to EOP-1A; therefore, EOP-1A entry will be required.

At 20% power, the APRM flow biased scram setpoint is ~95%. Reactor pressure will reach the scram setpoint well before APRMs reach their scram setpoint.

Distracters:
Answer B part 1 is correct. Part 2 is plausible because reactor power rises due to high pressure and because TCV Fast Closure signal occurs. A reactor scram on high APRM flux or TCV Fast Closure does not alone require entry into EOP-1A. An examinee may believe the pressure rise would be terminated by a high flux scram or TCV Fast Closure scram, so only entry into procedure 2.1.5 [Reactor Scram] would be required. It is wrong because reactor pressure rises to the scram setpoint and EOP-1A entry condition before APRM scram setpoint is reached and because TCV Fast Closure scram is bypassed, so EOP-1A entry will be required on reactor pressure >1050 psig.

Answer C part 1 is plausible to the examinee who confuses the effect of rising pressure on voids and boiling boundary and the resulting effect on reactor power. The examinee may believe rising pressure pushes the boiling boundary downward, lowering power. It is wrong because rising pressure causes voids in the core to collapse, thus raising the boiling boundary and reactor power. Part 2 is correct.

Answer D part 1 is plausible and wrong for the reason stated for distractor C. Part 2 is plausible and wrong for the reason stated for distractor B.

Technical References: TS 3.3.1.1 [RPS Instrumentation], Lesson plan COR002-09-02 [Digital Electro-Hydraulic Control](Rev 20), Alarm Card 9-5-2/C-4 [TSV & TCV Closure Trip Byp Chan A/B](Rev 49)

References to be provided to applicants during exam: none

Learning Objective: COR002-09-02 Obj LO-8b, Predict the consequences a malfunction of the following would have on DEH Control system: Failed open/closed bypass valve(s); Obj LO-7a, Given a specific DEH Control system malfunction, determine the effect on any of the following: Reactor power Obj LO-7b, Given a specific DEH Control system malfunction, determine the effect on any of the following: Reactor pressure; INT008-06-05 EO-1, List the entry conditions of Flowchart 1A

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(7),(10)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA Applicability:		
Top 10 Risk Significant Systems - RPS		

c. No change in Recirculation flow

A malfunction which does not affect Recirc flow or reactor power level will have no affect on the DEH system.

V. SYSTEM INTERRELATIONSHIPS

LO-03m A. Turbine High Pressure Fluid System

The DEH Control system regulates governor and bypass valve position by energizing servo-actuators in the Turbine High Pressure Fluid oil system.

LO-08b,c,d,e The Turbine High Pressure Fluid oil system also supplies the operating fluid for positioning the stop, reheat stop, and intercept valves. On a loss of system operating pressure, the system will not be able to respond to DEH commands and, if pressure drops low enough, these valves will go closed and control of the turbine and reactor pressure will be lost. Stopping steam flow to the turbine (or condenser if the bypass valves are open), will cause a decrease in reactor level and an increase in reactor pressure, which will cause reactor power to increase. At low reactor power (<.30%) this may cause a reactor scram due to overpower or overpressure. If power is above .30%, a reactor scram will occur due to Turbine Control Valve Fast Closure or Turbine Stop Valve Closure, and will cause reactor pressure to increase to the SRV setpoint.

B. Power Supply

LO-02

1. Detailed under system operation section.

LO-08q C. PMIS

Failure of PMIS would not directly affect the DEH control system. Depending on the nature and severity of the failure, historical data could be lost.

RPS Instrumentation
3.3.1.1

Table 3.3.1.1-1 (page 2 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
2. Average Power Range Monitors (continued)					
c. Neutron Flux - High (Fixed)	1	2	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.4 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.10(a,b) SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 120.0% RTP
d. Downscale	1	2	F	SR 3.3.1.1.4 SR 3.3.1.1.8 SR 3.3.1.1.9(a,b) SR 3.3.1.1.13	≥ 3.0% RTP
e. Inop	1,2	2	G	SR 3.3.1.1.4 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.13	NA
3. Reactor Vessel Pressure — High	1,2	2	G	SR 3.3.1.1.4 SR 3.3.1.1.9 SR 3.3.1.1.12(a,b) SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 1050 psig

SETPOINT	CIC	9-5-2/C-4
136.6 psig HP turbine inlet pressure < 29.5% RTP as measured by HP turbine inlet pressure (Tech Spec < 29.5% RTP/171.2 psig):		
1. (2704) TSV & TCV CLOSURE TRIP BYPASSED CHAN A1	1. MS-PS-14A	
2. (2705) TSV & TCV CLOSURE TRIP BYPASSED CHAN A2	2. MS-PS-14C	
3. (2706) TSV & TCV CLOSURE TRIP BYPASSED CHAN B1	3. MS-PS-14B	
4. (2707) TSV & TCV CLOSURE TRIP BYPASSED CHAN B2	4. MS-PS-14D	

PROBABLE CAUSES

- Lowering reactor power (i.e., reactor shutdown).

REFERENCES

- Technical Specification LCO 3.3.1.1, Reactor Protection System (RPS) Instrumentation.

TSV & TCV CLOSURE TRIP BYP CHAN A/B	PANEL/WINDOW: 9-5-2/C-4

1. AUTOMATIC ACTIONS

   1.1 When below setpoint on all four logic channels, TCV and TSV trips are bypassed. Actuation of a TCV or TSV trip under these conditions will not result in a scram.

2. OPERATOR OBSERVATION AND ACTION

   2.1 Ensure conditions of turbine and reactor are consistent with alarm.

   2.2 Whenever power is raised above setpoint, ensure alarm clears.

Examination Outline Cross-Reference	Level	RO
295004 (APE 4) Partial or Total Loss of DC Power/6 2.2.22 Knowledge of limiting conditions for operations and safety limits.	Tier#	1
	Group#	1
	K/A #	295004 G2.2.22
	Rating	4.0
	Revision	0
Revision Statement:		

Question 52

The plant is at 2% power during startup.

250 VDC Bus 1B loses power.

IAW TS 3.8.7 [Distributions Systems – Operating],

(1) Which one of the following systems must be declared inoperable as a result of this failure?

AND

(2) What is the Completion Time specified by TS 3.8.7 for declaring the supported system inoperable?

A. (1) LPCI Loop B
(2) 1 hour

B. (1) LPCI Loop B
(2) Immediately

C. (1) Core Spray B
(2) 1 hour

D. (1) Core Spray B
(2) Immediately

Answer: B

Explanation:
This is RO level, since it involves a ≤1 hr TS action statement. For the conditions given, the plant is in Mode 2, so TS 3.8.7 is applicable.

250 VDC Bus 1B provides power to various required Division 2 DC loads. 250 VDC Bus 1B supplies power to the 250 VDC Div 2 Starter rack, which supplies power to RHR Loop B Inboard Injection Valve RHR-MO-25B. This valve is closed in standby and automatically opens on an ECCS initiation signal. Since the valve is supported by 250 VDC Bus 1B and will not perform its safety function with 250 VDC Bus 1 B de-energized it must be declared inoperable IAW TS 3.8.7 Action D.1. The completion time for TS 3.8.7 Action D.1 is IMMEDIATELY.

Distracters:
Answer A part 1 is correct. Part 2 is plausible because a one hour completion time is sometimes given for other very limiting actions. For example, one action associated with DC power, TS 3.8.6 Action A.1, has a 1 hour completion time. It is wrong because TS 3.8.7 action D.1 completion time is IMMEDIATELY.

Answer C part 1 is plausible because Core Spray B has inboard and outboard injection valves as does RHR Loop B. It is wrong because Core Spray B injection valves are both AC powered. 250 VDC does not support Core Spray B system. Part 2 is plausible and wrong for the same reason given for distractor A.

Answer D part 1 is plausible and wrong for the same reason given for distractor C. Part 2 is correct.

Technical References: TS 3.8.7 [Distribution Systems – Operating], Procedure 2.2A_250DC.DIV2 [250 VDC Power Checklist (Div 2)] (Rev 2), TS 3.8.6 [Battery Cell Parameters]

References to be provided to applicants during exam: none

Learning Objective: INT007-05-09 EO-9, From memory, in MODES 1, 2, and 3 state the actions required in ≤ one hour if one 250 V DC electrical power distribution subsystem inoperable (LCO 3.8.7).

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(8)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	

PSA Applicability:
Top 10 Risk Significant System – Emergency DC Power

ATTACHMENT 2 250 VDC DIV 2 STARTER RACK BREAKER CHECKLIST

250 VDC DIV 2 STARTER RACK - (R-903-W) FED FROM 250 VDC SWITCHGEAR 1B

BREAKER NUMBER	DESCRIPTION	NORMAL POSITION	PERFORMED BY	VERIFIED BY	COMMENTS
EE-STR-250DIV2 (MO25B)	RHR-MO-25B RHR LOOP B INJECTION INBOARD (RH-529MV)	ON			
EE-STR-250DIV2 (MO53B)	RR-MO-53B B RR PUMP DISCHARGE VALVE (MO-02-53B)	ON			

PROCEDURE 2.2A_250DC.DIV2 REVISION 2 PAGE 5 OF 11

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 Distribution Systems — Operating

LCO 3.8.7 The AC and DC electrical power distribution subsystems in Table 3.8.7-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One AC electrical power distribution subsystem inoperable.	A.1 Restore AC electrical power distribution subsystem to OPERABLE status.	8 hours AND 16 hours from discovery of failure to meet LCO
B. One 125 V DC electrical power distribution subsystem inoperable.	B.1 Restore 125 V DC electrical power distribution subsystem to OPERABLE status.	2 hours AND 16 hours from discovery of failure to meet LCO

(continued)

Distribution Systems — Operating
3.8.7

Table 3.8.7-1 (page 1 of 1)
AC and DC Electrical Power Distribution Systems

TYPE	VOLTAGE	DIVISION 1*	DIVISION 2*
AC safety buses	4160 V	Critical Bus 1F	Critical Bus 1G
	480 V	Critical Bus 1F	Critical Bus 1G
DC buses	125 V	Bus 1A	Bus 1B
	250 V	Bus 1A	Bus 1B

* Each division of the AC, the 125 V DC, and the 250 V DC electrical power distribution systems is a subsystem.

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Required Action and associated Completion Time of Condition A or B not met.	C.1	Be in MODE 3.	12 hours
	AND		
	C.2	Be in MODE 4.	36 hours
D. One or more 250 V DC electrical power distribution subsystems inoperable.	D.1	Declare associated supported feature(s) inoperable.	Immediately
E. Two or more electrical power distribution subsystems inoperable that result in a loss of function.	E.1	Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.7.1	Verify correct breaker alignments and voltage to required AC and DC, electrical power distribution subsystems.	In accordance with the Surveillance Frequency Control Program

3.8 ELECTRICAL POWER SYSTEMS

3.8.6 Battery Cell Parameters

LCO 3.8.6 Battery cell parameters for the 125 V and 250 V batteries shall be within the limits of Table 3.8.6-1.

AND

Battery cell average electrolyte temperature for the 125 V and 250 V batteries shall be within required limit.

APPLICABILITY: When associated DC electrical power subsystems are required to be OPERABLE.

ACTIONS

-----NOTE-----
Separate Condition entry is allowed for each battery.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more batteries with one or more battery cell parameters not within Category A or B limits.	A.1 Verify pilot cells electrolyte level and float voltage meet Table 3.8.6-1 Category C limits. AND	1 hour

Examination Outline Cross-Reference	Level	RO
295032 (EPE 9) High Secondary Containment Area Temperature / 5 Knowledge of the reasons for the following responses as they apply to HIGH SECONDARY CONTAINMENT AREA TEMPERATURE: EK3.03 Isolating affected systems	Tier#	1
	Group#	2
	K/A #	295032 EK3.03
	Rating	3.8
	Revision	0
Revision Statement:		

Question 53

MSL tunnel area temperatures are rising due to a steam leak from MSL B while operating at 100% power.

IAW EOP-5A, closing MSIVs is REQUIRED ____(1)____ a Secondary Containment area temperature exceeds Maximum Normal Operating (MNO) value in order to ____(2)____.

A. (1) before
(2) prevent uncontrolled depressurization of the RPV

B. (1) before
(2) reduce the energy input into secondary containment

C. (1) ONLY after
(2) prevent uncontrolled depressurization of the RPV

D. (1) ONLY after
(2) reduce the energy input into secondary containment

Answer: D
Explanation: The MSL tunnel is in Secondary Containment. With a primary system discharging into secondary containment, EOP-5A steps SC/T-3 and SC-3 require isolating the system WHEN any area exceeds its MNO temperature. IAW PSTGs, system isolation is required when any area temperature exceeds its MNO value in order to terminate the heat addition from a primary system that is discharging into the secondary containment to prevent reaching Maximum Safe Operating temperature.
Distracters:

Answer A part 1 is plausible because IAW EOP-5A steps SC-4 and SC-5, a scram is required before any area temperature reaches its Max Safe Operating (MSO) limit. It is wrong because EOP-5A steps SC/T-3 requires step SC-3, isolating the system, to be performed when any area temperature exceeds its MNO limit, not before. Part 2 is plausible because a MSL leak could result in uncontrolled RPV depressurization if large enough. A reactor scram is inevitable with MSL tunnel temperature continuing to rise, and once the Reactor Mode Switch is placed to Shutdown, automatic MSIV closure on RPV low pressure is bypassed. Operator action would be necessary to close MSIVs to prevent uncontrolled depressurization. It is wrong because the EOP-5A basis for isolating the system is to terminate the heat addition into secondary containment from a high energy leak. EOP-1A contains actions for controlling RPV pressure.

Answer B part 1 is plausible and wrong for the same reason stated for distractor A. Part 2 is correct.

Answer C part 1 is correct. Part 2 is plausible and wrong for the same reason stated for distractor A.

Technical References: EOP-5A [Secondary Containment Control/Radioactivity Release Control](Rev 19), PSTG [AMP-TBD00 EOP Technical Basis](Rev 10)

References to be provided to applicants during exam: none

Learning Objective: : INT008-06-17 EOP Flowchart 5A Secondary Containment and Radioactivity Release Control, EO-7. Given plant conditions and EOP flowchart 5A, SECONDARY CONTAINMENT CONTROL and RADIOACTIVITY RELEASE CONTROL, state the reasons for the actions contained in the steps.

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	12/2015 ILT NRC Q#25
	New	
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(5),(10)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	

PSA Applicability:
N/A

Question 25

Secondary Containment radiation levels are rising due to a primary system leak while operating at power.

Which one of the following completes the statement below regarding when and why a reactor Scram is required?

A Reactor Scram is required _____(1)_____ Secondary Containment radiation levels exceed Maximum Safe Operating Radiation value to _____(2)_____.

A. (1) before
(2) reduce the driving head of the primary system discharging into secondary containment

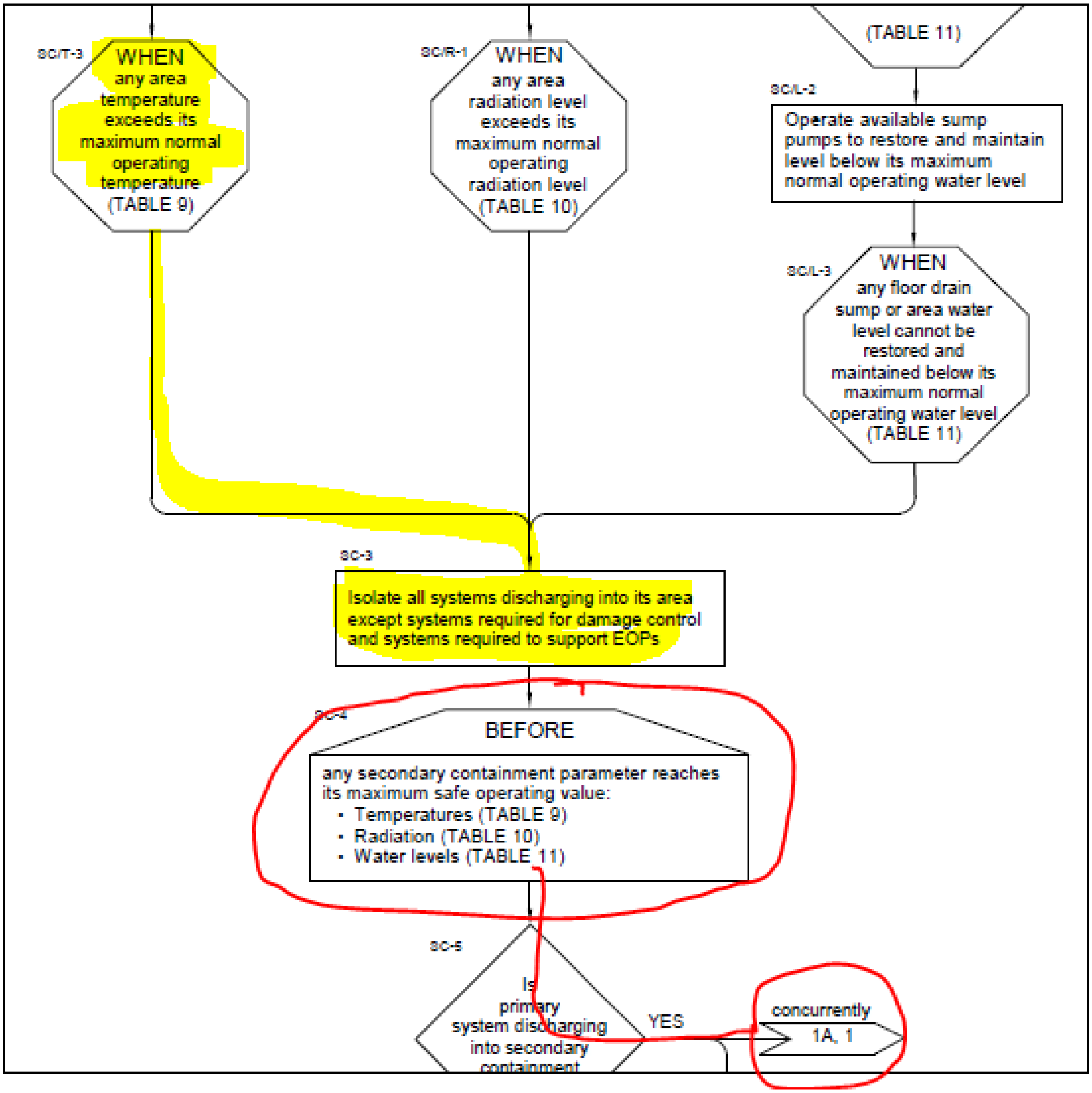
B. (1) before
(2) ensure the reactor is shut down before radiation release rates exceed the values for an ALERT

C. (1) ONLY after
(2) reduce the driving head of the primary system discharging into secondary containment

D. (1) ONLY after
(2) ensure the reactor is shut down before radiation release rates exceed the values for an ALERT

Answer:
A. (1) before (2) reduce the driving head of the primary system discharging into secondary

From EOP-5A


(TABLE 11)
SC/T-3
WHEN
any area temperature exceeds its maximum normal operating temperature (TABLE 9)
SC/R-1
WHEN
any area radiation level exceeds its maximum normal operating radiation level (TABLE 10)
SC/L-2
Operate available sump pumps to restore and maintain level below its maximum normal operating water level
SC/L-3
WHEN
any floor drain sump or area water level cannot be restored and maintained below its maximum normal operating water level (TABLE 11)
SC-3
Isolate all systems discharging into its area except systems required for damage control and systems required to support EOPs
SC-4
BEFORE
any secondary containment parameter reaches its maximum safe operating value:
• Temperatures (TABLE 9)
• Radiation (TABLE 10)
• Water levels (TABLE 11)
SC-5
Is primary system discharging into secondary containment
YES
concurrently
1A, 1

9	SECONDARY CONTAINMENT TEMPERATURES SPDS 16			
Maximum Normal Operating Value		Maximum Safe Operating Value		
Area	Any Temp. Switch Alarmed	Area	Value (°F)	Actual Value
NE Quad	RCIC-TS-77A RCIC-TS-77C	NE Quad	195	
SE Quad	RWCU-TS-117F	SE Quad	195	
NW Quad	RHR-TS-99C	NW Quad	195	
SW Quad and HPCI Room	RHR-TS-99G HPCI-TS-105B HPCI-TS-105D	SW Quad and HPCI Room	195	
1001' El. 976' El. 958' El.	RWCU-TS-117B	1001' El. 976' El. 958' El.	195	
903' El. and 931' El.	RHR-TS-99A RHR-TS-99E MS-TS-126A MS-TS-126C RWCU-TS-117E RWCU-TS-117A HPCI-TS-105A	903' El. and 931' El.	195	

PSTG/SATG Step

SC/T-3 When an area temperature exceeds its maximum normal operating temperature (Table SC 1), isolate all systems that are discharging into the area except systems required for damage control and systems required to be operated by the PSTG.

Discussion

A fire and a steam/liquid discharge from high-energy systems are two possible sources from which heat may be added to the secondary containment at a rate sufficient to increase area temperatures to above the maximum normal operating temperatures. Step SC/T-3 terminates the possible heat addition from one of these sources, the high-energy systems. Guidance on fighting fires is provided in other plant procedures.

Continued operation of damage control systems required to protect personnel, plant structures, or essential equipment is permitted since these objectives generally take precedence over control of secondary containment area temperatures. Examples may include fire suppression systems, alternative spent fuel pool makeup and cooling methods, and portable sprays being used to scrub unisolable radioactivity releases.

The objectives of RPV Control, Primary Containment Control, and the PSTG contingencies are given higher priority than the objectives of Secondary Containment Control. Systems that must be operated to support the performance of other steps of the PSTGs therefore need not be isolated here.

"Systems that may be required" include not only those explicitly identified in other PSTG steps but also auxiliaries that may be needed to permit continued use of those systems, support the accomplishment of overall PSTG objectives, or avoid further degradation of plant conditions. The determination of whether continued operation of a system is "required" necessitates a judgment based on the nature of the event and current plant conditions. The benefits of continued operation must be balanced against potential loss of essential equipment and area access that could further complicate efforts to stabilize the plant. For example, if loss of condenser vacuum could result in loss of preferred injection systems or increase the offsite radioactivity release rate, systems needed to maintain condenser vacuum may remain in operation.

Examination Outline Cross-Reference	Level	RO
201003 (SF1 CRDM) Control Rod and Drive Mechanism Knowledge of the effect that a loss or malfunction of the following will have on the CONTROL ROD AND DRIVE MECHANISM: K6.02 Reactor pressure	Tier#	2
	Group#	2
	K/A #	201003 K6.02
	Rating	3.0
	Revision	1
Revision Statement: Rev 1 - Made answer C=900, A=960, and B=940 IAW NRC comment from “free review”		

Question 54

The plant is at 80% power when the following conditions occur:

- HCU accumulator for withdrawn control rod 18-23 is declared inoperable due to low pressure
- Running CRD pump trips
- DEH malfunction causes reactor pressure to slowly lower

Which one of the following is the LOWEST **reactor pressure** which will fully insert control rod 18-23 within the TS Allowable Control Rod Scram Time under these conditions?

A. 960 psig

B. 940 psig

C. 900 psig

D. 835 psig

Answer: C
Explanation: Per Procedure 2.2.8, below ~ 900 psig reactor pressure, hydraulic accumulators are required to ensure any withdrawn control rods are fully scrammed within required time. Answer C is the lowest answer given that is ≥ 900 psig.
Distracters:

Answer A is plausible because 960 psig is the setpoint for CRD HCU accumulator low pressure alarm. It is wrong because it is not the lowest pressure given that is above 900 psig.

Answer B is plausible because 940 psig is just above the action point criteria IAW alarm card 9-5-2/G-6. Immediate action is required IAW alarm card 9-5-2/G-6 states if CRD charging water pressure indicated on CRD-PI-302 is <940 psig, along with reactor pressure <900 psig and a CRD HCU accumulator for a withdrawn control rod inoperable. It is wrong for the same reason stated for distractor A.

Answer D is plausible because it reflects a familiar number associated with reactor pressure. 835 psig reactor pressure is the TS setpoint for Group 1 isolation on low reactor pressure. It is wrong because it is below the ~900 psig reactor pressure necessary to ensure scram times are met with inoperable CRD HCU accumulators and low charging water header pressure.

Technical References: Procedure 2.2.8 [Control Rod Drive Hydraulic System](Rev 106], Alarm Card 9-5-2/G-6 [CRD Accum Low Press or High Level](Rev 49), Lesson Plan COR002-04-02 [OPS Control Rod Drive Hydraulics](Rev 30), TS Table 3.3.6.1-1 [Primary Containment Isolation Instrumentation]

References to be provided to applicants during exam: none

Learning Objective: COR002-04-02 Obj LO 13g. Describe the interrelationships between the Control Rod Drive Hydraulic system (CRDH) and the following: Control Rod Drive Mechanisms;
COR002-04-02 Obj LO-11i, Predict the consequences a malfunction of the following would have on the CRDH system: CRDH pump trip

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(6)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	

PSA Applicability:
N/A

▪ 1.2.5.1 Failure of CRD pumps stops cooling water flow to drives which shortens seal life. Failure of CRD pumps also allows CRD hydraulic accumulators to slowly discharge through inlet scram valve and/or charging water header check valve leakage. This is of special concern during initial stages of plant startup when reactor pressure is insufficient to accomplish a scram. Below ~ 900 psig reactor pressure, hydraulic accumulators are required to ensure any withdrawn control rods are fully scrammed within required time.

PROCEDURE 2.2.8 REVISION 106 PAGE 144 OF 150

Lesson Number:	COR002-04-02	Revision:	30

3. Shifting CRDH pumps

The standby pump is checked for proper lubrication, cooling water flow, valve positioning, as well as being vented. The flow control is taken to MANUAL to prevent its cycling and the standby pump is started. As soon as the local and remote indications indicate that the pump is running properly, the original running pump is secured. The flow controller is adjusted to approximately 50 gpm and placed in AUTO.

B. Abnormal Operations

LO-11i 1. Loss of a CRD pump

a. A CRDH pump failure should be indicated by annunciators. The probable alarms would be CRD PUMP BREAKER TRIP, CRD PUMP LOW SUCTION PRESSURE, and CRD high temperature. Indications of a pump failure would be charging water pressure low, CRD pump Run light off, and CRDM temperature increasing.

There is no automatic start function, but the other pump can be started by the operator.

b. Effects on plant operations without a CRDH pump operating:

1. The operator will not be able to move control rods by normal rod movement.

2. The accumulators will start to discharge because of back leakage through the check valves (this can be minimized by shutting the charging header manual isolation valve). If reactor pressure is above ≈900 psig, normal scram times will be met even without the accumulators.

LO-12c 3. CRD cooling will be lost. Operation for long periods at high temperatures will reduce the life of the CRDM seals.

LO-12a, d 4. Recirculation pump and RWCU pump seal supply will be lost. Operations without a clean supply of seal water to the Recirculation and RWCU Pumps could cause damage to these seals.

Lesson Number:	COR002-04-02	Revision:	30

e. A loss of all A.C. power will result in the unavailability of the CRDH system for normal rod movement or CRDM cooling. The scram valves and backup scram valves will perform their function and the plant will be shutdown; consequently, the unavailability of the CRDH system is not a major concern initially.

With the charging water header depressurized, the HCU accumulators will start depressurizing via check valve leakage. This would become a concern if reactor pressure was less than ≈900 psig because the accumulators would not be able to force rods into the core, within the required time, due to low pressure in the event of a scram.

LO-05e 11. CRDH Pump Runout

CRDH pump runout could occur due to the high flow demand that would be present due to a scram. The resultant lack of back pressure on the pump would cause an increase in motor amps with possible motor winding damage due to high current as a result. The overcurrent trip on the CRDH pump would protect the pump motor from this condition if it were to occur.

LO-04a The charging water flow restricting orifice and the flow control valve are designed to prevent this.

LO-11j 12. Loss of D.C.

A loss of the 125V DC bus AA2 (BB2) would cause a failure of the backup scram valve 140A (140B) to open when required.

125 VDC Panel AA3 (BB3) provides breaker control power for CRDH pump A (B). A loss of control power would result in the inability to start or stop the pumps from the Control Room and would also prevent the pumps from tripping on any automatic trip signal (i.e., low suction pressure). Operation of the pump breaker associated with the loss of control power would have to be accomplished by local breaker operation at the 480V AC Bus.

V. SYSTEM INTERRELATIONSHIPS

LO-13a
SO-10a A. Condensate Storage Tank (CST)

The "A" CST is the normal suction for the CRDH pumps, and the return from the CRDH pump minimum flow line discharges to the "A" CST.

SETPOINT	CIC	9-5-2/G-6
1. (2756) CRD ACCUM LOW PRESSURE at 960 psig	1. CRD-PS-130(XX-YY)	
2. (2756) CRD ACCUM HIGH LEVEL at 37 cc	2. CRD-LS-129(XX-YY)	

PROBABLE CAUSES

- Instrument block seal leakage.

REFERENCES

- Technical Specifications LCO 3.1.5, Control Rod Scram Accumulators.
- System Operating Procedure 2.2.8, Control Rod Drive Hydraulic System.

CRD ACCUM LOW PRESS OR HIGH LEVEL

PANEL/WINDOW: 9-5-2/G-6

1. OPERATOR OBSERVATION AND ACTION

NOTE – Steps 1.1 and 1.2 can be performed concurrently.

1.1 On Panel 9-5, verify following parameters:
- CRD-PI-302, CHG WTR PRESS, at 1425 psig to 1475 psig.
- CRD-DPI-303, DR WTR DP, at 260 to 270 psid.
- CRD-FI-306, CL WTR FLOW, at 45 to 55 gpm.

1.1.1 Correct any out of normal parameter per Procedure 2.2.8.

1.2 Determine HCU accumulator alarm corrective action per Procedure 2.2.8.

1.2.1 Enter applicable LCO 3.1.5, Conditions and Required Actions.

1.3 IF all of following:
- **Reactor pressure < 900 psi.**
- **One control rod accumulator inoperable with associated control rod not fully inserted.**
- **CRD-PI-302, CHG WTR PRESS < 940 psig.**

THEN perform following:

1.3.1 Immediately insert affected control rod.

1.3.2 Monitor for other HCU accumulator low pressure alarms.

1.3.3 IF a second control rod accumulator becomes inoperable with associated control rod not fully inserted, THEN SCRAM and enter Procedure 2.1.5.

Scram Actions

Scram Actions

Primary Containment Isolation Instrumentation
3.3.6.1

Table 3.3.6.1-1 (page 1 of 3)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Main Steam Line Isolation					
a. Reactor Vessel Water Level - Low Low Low (Level 1)	1,2,3	2	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.6	≥ -113 inches
b. Main Steam Line Pressure - Low	1	2	E	SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.6	≥ 835 psig

Examination Outline Cross-Reference	Level	RO
295013 (APE 13) High Suppression Pool Temperature. / 5 2.4.18 Knowledge of the specific bases for EOPs.	Tier#	1
	Group#	2
	K/A #	295013 G2.4.18
	Rating	3.3
	Revision	0
Revision Statement:		

Question 55

The EOP-3A entry condition for high Suppression Pool temperature is the TS 3.6.2.1 [Suppression Pool Average Temperature] limit ________________.

A. when power is ≤1%.

B. at which plant shutdown is required.

C. during testing that adds heat to the Suppression Pool when power is >1%.

D. with NO testing in progress that adds heat to the Suppression Pool with power above 1%.

Answer: D
Explanation: The EOP-3A entry condition for high SP temperature is 95°F. The basis is this represents the most limiting (lowest) value allowed for SP temperature listed in LCO 3.6.2.1 [Suppression Pool Average Temperature] during Modes 1, 2, and 3.
Distracters: Answer A is plausible because it reflects a limit listed in LCO 3.6.2.1. It is the LCO limit when power is ≤1% and is 110°F. It is wrong because it is not the EOP-3A entry condition for high SP temperature, because it is not the most limiting LCO value. Answer B is plausible because TS 3.6.2.1 Action D.1 requires immediately placing the Reactor Mode Switch to shutdown if SP temperature is >110°F when power is >1%. It is wrong because 110°F is not the most limiting LCO value. (This distractor is RO knowledge, since it involves a ≤1hr TS action.)

Answer C is plausible because it reflects a limit listed in LCO 3.6.2.1. It is the LCO limit when power is >1% and testing is adding heat to SP and is 105°F. It is wrong because 105°F is not the most limiting LCO value.		
Technical References: PSTG [AMP-TBD00 EOP Technical Basis](Rev 9), TS 3.6.2.1 [Suppression Pool Average Temperature], Lesson plan INT008-06-13 [OPS EOP Flowchart 3A - Primary Containment Control](Rev 22)		
References to be provided to applicants during exam: none		
Learning Objective: INT008-06-13 EO-1, List the entry conditions for Flowchart 3A and briefly describe the importance of each.		
Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(10)	
Level of Difficulty:	2	
SRO Only Justification:	N/A	
PSA Applicability:		
N/A		

PRIMARY CONTAINMENT CONTROL EMERGENCY PROCEDURE GUIDELINE

PURPOSE

The purpose of this guideline is to:

- Maintain primary containment integrity, and
- Protect equipment in the primary containment.

ENTRY CONDITIONS

The entry conditions for this guideline are any of the following:

- Average suppression pool temperature above 95°F (most limiting suppression pool temperature LCO)
- Average drywell temperature above 150°F (drywell temperature LCO (150°F) or maximum normal operating temperature (150°F), whichever is higher)
- Drywell pressure above 1.84 psig (high drywell pressure scram setpoint)
- Suppression pool water level above 12.92 ft wide range, +2 in. narrow range (maximum suppression pool water level LCO)
- Suppression pool water level below 12.59 ft wide range, -2 in. narrow range (minimum suppression pool water level LCO)
- Primary containment hydrogen concentration above 1% (high hydrogen alarm setpoint)

Lesson Number: INT008-08-13	Revision: 22

Entry conditions based on plant parameters are the following:

LO-01

1. Average torus water temperature above 95 °F: This temperature is the most limiting torus water temperature LCO. ESP 5.8.9 provides detailed instructions for computing the average torus water temperature.

2. Average drywell temperature above 150°F: This temperature has been determined by engineering analysis as being the maximum normal operating average drywell temperature. EP 5.8.10 provides detailed instructions for computing this weighted average temperature.

3. Drywell pressure above 1.84 psig: This pressure corresponds to the high drywell pressure scram set-point.

4. Torus water level above +2 in.: This water level corresponds to the maximum suppression pool water volume LCO.

5. Torus water level below -2 in.: This water level corresponds to the minimum suppression pool water volume LCO.

6. Primary containment H_2 concentration above 1%: This concentration is the high H_2 alarm set-point.

The set-points of these entry conditions provide advance warning of potential emergency conditions, allowing action to be taken sufficiently early to prevent more severe consequences.

D. PC-1 - Subsequent steps may require the initiation of torus or drywell sprays. The steps for initiating torus sprays is located at point [T] in the Flowchart, and the steps for initiating drywell sprays is located at point [D] in the Flowchart. This override applies during the execution of all subsequent steps.

E. PC-2 - Flowchart 3A consists of five parallel action paths. Actions taken to control any one of the key primary containment parameters may directly affect control of the other parameters and thus all flowpaths are performed concurrently. This is necessary because the primary containment functions as a closed thermodynamic system and the transient responses of all primary containment parameters are directly interrelated. For example:

1. Changes in torus water temperature can directly change primary containment pressure.

2. Changes in drywell temperature can directly change primary containment pressure.

3. Changes in torus water level can directly change torus pressure. Prioritization of any single flow path is not possible since symptomatic

3.6 CONTAINMENT SYSTEMS

3.6.2.1 Suppression Pool Average Temperature

LCO 3.6.2.1 Suppression pool average temperature shall be:

a. ≤ 95°F when THERMAL POWER is > 1% RTP and no testing that adds heat to the suppression pool is being performed;

b. ≤ 105°F when THERMAL POWER is > 1% RTP and testing that adds heat to the suppression pool is being performed; and

c. ≤ 110°F when THERMAL POWER is ≤ 1% RTP.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Suppression pool average temperature > 95°F but ≤ 110°F.	A.1	Verify suppression pool average temperature ≤ 110°F.	Once per hour
AND	AND		
THERMAL POWER is > 1% RTP.	A.2	Restore suppression pool average temperature to ≤ 95°F.	24 hours
AND			
Not performing testing that adds heat to the suppression pool.			

(continued)

Suppression Pool Average Temperature
3.6.2.1

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. Required Action and associated Completion Time of Condition A not met.	B.1	Reduce THERMAL POWER to ≤ 1% RTP.	12 hours
C. Suppression pool average temperature > 105°F. AND THERMAL POWER is > 1% RTP. AND Performing testing that adds heat to the suppression pool.	C.1	Suspend all testing that adds heat to the suppression pool.	Immediately
D. Suppression pool average temperature > 110°F but ≤ 120°F.	D.1	Place the reactor mode switch in the shutdown position.	Immediately
	AND		
	D.2	Verify suppression pool average temperature ≤ 120°F.	Once per 30 minutes
	AND		
	D.3	Be in MODE 4.	36 hours

(continued)

Examination Outline Cross-Reference	Level	RO
295035 (EPE 12) Secondary Containment High Differential Pressure / 5 Ability to operate and/or monitor the following as they apply to SECONDARY CONTAINMENT HIGH DIFFERENTIAL PRESSURE: EA1.02 SBGT/FRVS	Tier#	1
	Group#	2
	K/A #	295035 EA1.02
	Rating	3.8
	Revision	0
Revision Statement:		

Question 56

Reactor Building H & V exhaust fans tripped with the plant at 100% power.

SGT A was placed in service by the operator IAW Procedure 2.2.73 [Standby Gas Treatment System] due to secondary containment high differential pressure.

According to Procedure 2.2.73, SGT-DPIC-546 [RX BLDG/SGT DP] setpoint is required to be adjusted to maintain:

Reactor Building differential pressure **less** than or equal to ____(1)____ AND

SGT discharge header flow **greater** than or equal to ____(2)____.

A. (1) -0.25" wg
(2) 800 scfm

B. (1) -0.25" wg
(2) 1780 scfm

C. (1) -0.50" wg
(2) 800 scfm

D. (1) -0.50" wg
(2) 1780 scfm

Answer: A

Explanation:
SGT system prevents out-leakage from secondary containment during periods of primary and/or secondary containment isolation by holding it at a sub atmospheric pressure of ≤ -0.25" wg. Procedure 2.2.73 section 6 is for manual operation to maintain RB differential pressure. Step 6.2 requires adjusting SGT-DPIC-546 setpoint to less than or equal to -0.25" wg. Step 6.6 further requires adjusting SGT-DPIC-546, as necessary to obtain greater than or equal to 800 scfm on SGT-FI-545 [SGT

Discharge Header Flow] to maintain the SGT filter train electric heaters energized. Heaters are necessary to maintain low moisture in the charcoal filters by reducing the relative humidity of the air stream and trip if flow falls below 800 scfm.

Distracters:

Answer B part 1 is correct. Part 2 is plausible because the design flow rate for a single SGT subsystem is 1780 scfm. It is wrong because actual flow rate to maintain -0.25" wg differential pressure varies with plant conditions, so Procedure 2.2.73 specifies 800 scfm as the minimum flow rate in order to maintain heaters energized, and that also prevents auto start of a SGT subsystem that has been placed in STANDBY.

Answer C part 1 is plausible because it reflects the differential pressure listed in Procedure 2.2.73 at which step 6.7.1.2 requires placing one SGT subsystem in STANDBY. It is wrong because this is the low limit of the desired differential control band, and Procedure 2.2.73 specifies setting the DP controller to ≤ -0.25" wg

Answer D part 1 is plausible and wrong for the same reason given for distractor C. Part 2 is plausible and wrong for the same reason given for distractor B.

Technical References: Procedure 2.2.73 [Standby Gas Treatment System](Rev 58)

References to be provided to applicants during exam: none

Learning Objective: COR002-28-02 Obj LO-8c, Describe the Standby Gas Treatment System design features and/or interlocks that provide for the following: Moisture removal; 3, State the design bases for the SGT System as described in the associated Student Text.

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(10)	
Level of Difficulty:	2	
SRO Only Justification:	N/A	

PSA Applicability:

N/A

6. MANUAL OPERATION TO MAINTAIN REACTOR BUILDING DIFFERENTIAL PRESSURE

NOTE – Reactor Building fans trip after 45 second time delay from either of following:
- Reactor Building above -0.15" wg.
- Reactor Building below -0.45" wg.

6.1 At VBD-R, **PLACE** SGT-DPIC-546, RX BLDG/SGT DP, in AUTO

6.2 **ADJUST** SGT-DPIC-546 setpoint to less than or equal to -0.25" wg.

NOTE – Both SGT Subsystems may be placed in service for EOPs.

CAUTION – Secondary Containment pressure transient and TS LCO 3.6.4.1 entry may occur from starting SGT.

6.3 IF EF-R-1E, SGT A EXHAUST FAN, labeled PREFERRED, THEN at VBD-K, **PERFORM** following:

6.3.1 **PLACE** EF-R-1E in RUN.

6.3.2 **VERIFY** following:
- SGT-AO-249, SGT A INLET, opens.
- SGT-AO-251, SGT A DISCHARGE, opens.

6.4 IF EF-R-1F, SGT B EXHAUST FAN, labeled PREFERRED, THEN at VBD-K, **PERFORM** following:

6.4.1 **PLACE** EF-R-1F in RUN.

6.4.2 **VERIFY** following:
- SGT-AO-250, SGT B INLET, opens.
- SGT-AO-252, SGT B DISCHARGE, opens.

6.5 **REMOVE** Reactor Building H&V System from service per Procedure 2.2.47.

6.6 **ADJUST** SGT-DPIC-546, RX BLDG/SGT DP, as necessary, to obtain greater than or equal to 800 scfm on SGT-FI-545, SGT DISCHARGE HEADER FLOW, to maintain electric heater energized.

NOTE 1 – Due to a significant, variable air flow from Secondary Containment to atmosphere via leaking RRMG HV ducts, pressure may fall below -0.50" wg.

NOTE 2 – Preferred fan does not set a requirement, but is meant to help equalize charcoal run time. Either fan may be run at any time based upon circumstance.

6.7 IF HV-DPR-835, RX BLDG/ATMOS DP, less than or equal to -0.50" wg, THEN **PERFORM** following:

6.7.1 IF both SGT fans running, THEN **PERFORM** following:

6.7.1.1 **PLACE** PREFERRED SGT fan switch in RUN.

6.7.1.2 **CYCLE** Non-Preferred SGT fan switch to OFF and then STANDBY.

6.7.1.3 **PERFORM** following:

a. **VERIFY** SGT fan in STANDBY stops.

b. IF EF-R-1E in STANDBY, THEN **VERIFY** following closed:

- SGT-AO-249, SGT A INLET.
- SGT-AO-251, SGT A DISCHARGE.

c. IF EF-R-1F in STANDBY, THEN **VERIFY** following closed:

- SGT-AO-250, SGT B INLET.
- SGT-AO-252, SGT B DISCHARGE.

6.7.1.4 **VERIFY** HV-DPR-835 stabilized.

6.7.2 IF only EF-R-1E running, THEN **PLACE** SGT-DPCV546A to OPEN.

6.7.3 IF only EF-R-1F running, THEN **PLACE** SGT-DPCV546B to OPEN.

ATTACHMENT 3 INFORMATION SHEET

1.2.3 Each assembly consists of an air operated inlet valve, moisture separator, prefilter, air heater, high efficiency filter, activated carbon iodine adsorber, a second high efficiency filter, fan, an air operated outlet valve, and an air operated differential pressure control valve.

1.2.3.1 Air Operated Inlet Valve SGT-AO-249 (SGT-AO-250) opens when SGT A (B) fan starts. Valve fails open on a loss of air or control power.

1.2.3.2 Moisture separator is designed to remove entrained water droplets and mist to prevent plugging of high efficiency filters and carbon iodine adsorber.

1.2.3.3 Prefilter is designed to remove large particulates to prevent plugging of high efficiency filters.

1.2.3.4 Air heater is composed of a 2.8 kW and 5 kW heating element. Air heaters will turn on when flow rate through subsystem > 800 scfm and temperature of air < 170°F. Air heater reduces relative humidity of air stream to ~ 70%.

1.2.3.5 First high efficiency filter removes particulates of > 0.30 micron in size to prevent plugging of carbon iodine adsorber.

1.2.3.6 Carbon iodine adsorber is an activated carbon iodide-impregnated filter. This filter is capable of removing 95% of iodine in air stream at a temperature of 30°C when relative humidity of air stream is ~ 70%.

1.2.3.7 Second high efficiency filter removes particulates of > 0.30 microns in size to remove any carryover from carbon filter and provide final filtering of air stream.

1.2.3.8 SGT A (B) fan develops necessary flow to maintain negative Reactor Building pressure. Design flow rate of fan is 1780 cfm ± 10%. Air operated vortex damper on fan controls differential pressure across filter train. Fan is powered from MCC-K (MCC-S).

1.2.3.9 Air Operated Outlet Valve SGT-AO-251 (SGT-AO-252) opens when SGT A (B) fan starts. Valve fails open on a loss of air or control power.

Examination Outline Cross-Reference	Level	RO
295031 (EPE 8) Reactor Low Water Level / 2 2.4.2 Knowledge of system setpoints, interlocks and automatic actions associated with EOP entry conditions.	Tier#	1
	Group#	1
	K/A #	295031 G2.4.2
	Rating	4.5
	Revision	0
Revision Statement:		

Question 57

(1) The EOP entry condition for low reactor water level is listed on EOP-1A as:

RPV water level below ________ inches.

(2) Which one of the following valves receive an isolation signal at that setpoint for RPV water level?

A. (1) +3 inches
(2) RR-AO-741, INBD ISOL VLV

B. (1) +3 inches
(2) RHR-SSV-95, RHR SAMPLE VALVE

C. (1) +7 inches
(2) RR-AO-741, INBD ISOL VLV

D. (1) +7 inches
(2) RHR-SSV-95, RHR SAMPLE VALVE

Answer: B

Explanation:
The EOP-1A entry condition for low RPV level is level below +3". The setpoint for Group 2 isolation on low RPV level is level below +3". RHR-SSV-95, RHR SAMPLE VALVE is a Group 2 valve and receives an isolation signal when RPV level falls below +3".

Distracters:
Answers A part 1 is correct. Part 2 is plausible because it is also a sample valve that isolates on low reactor watetr level. It is wrong because RR-AO-741, INBD ISOL VLV is a Group 7 valve and isolates only when level falls below -113".

Answer C part 1 is plausible because the TS setpoint for the low water level scram is + 3”, but the actual setpoint is +7.81”. The examinee who believes the EOP-1A entry condition is synonymous with the actual low water level scram setpoint would choose this answer. It is wrong because the EOP-1A entry condition is +3”. Part 2 is plausible and wrong for the same reason given for distractor A.

Answer D part 1 is plausible and wrong for the same reason given for distractor C. Part 2 is correct.

Technical References: EOP-1A [RPV Control](Rev 22), procedure 2.1.22 [Recovering from a Group Isolation](Rev 63), Alarm Card 9-5-2/D-1 [Reactor Low Level Trip](Rev 49)

References to be provided to applicants during exam: none

Learning Objective: INT008-06-05 EO-1, List the entry conditions of Flowchart 1A

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(7)	
Level of Difficulty:	2	
SRO Only Justification:	N/A	
PSA Applicability:		
Top 10 Risk Significant System – PCIS		

From EOP-1A:

ANY OF FOLLOWING ENTRY CONDITIONS:

- RPV pressure above 1050 psig
- condition which requires reactor scram
  AND
  reactor power above 3% or cannot be determined
- RPV water level below +3 in.
- drywell pressure above 1.84 psig

PROCEDURE 2.1.22 REVISION 63 PAGE 5 OF 30

5.2 Upon full Group 2 Isolation, ensure following actions have occurred:

5.2.1 If RHR in Shutdown Cooling, running RHR pump has tripped.

5.2.2 Following valves have closed:

NOTE – All valve positions can be determined from containment mimic on Panel 9-3 unless otherwise specified.

5.2.2.1 RHR-SSV-95 (Div 1), RHR SAMPLE VALVE.

5.2.2.2 RHR-SSV-96 (Div 1), RHR SAMPLE VALVE.

5.2.2.3 RHR-SSV-60 (Div 2), RHR SAMPLE VALVE.

5.2.2.4 RHR-SSV-61 (Div 2), RHR SAMPLE VALVE.

5.2.2.36 PC-MO-1302 (Div 1), TORUS N_2 SUPPLY ISOLATION VLV (Panel P2), if not in OVERRIDE.

5.3 Determine isolation cause:

ISOLATION	ALLOWABLE VALUE	COMMENTS
Low Reactor Water Level	≥ 3"	
Drywell Pressure	≤ 1.84 psig	Ensure Group 6 Isolation.
RPS Power Supply Failure	Loss of power	

SETPOINT	CIC	9-5-2/D-1
7.81" (Tech Spec ≥ 3"):		
1. (2665) REACTOR LOW LEVEL CHAN A1 TRIP	1. NBI-LIS-101A	
2. (2666) REACTOR LOW LEVEL CHAN A2 TRIP	2. NBI-LIS-101C	
3. (2667) REACTOR LOW LEVEL CHAN B1 TRIP	3. NBI-LIS-101B	
4. (2668) REACTOR LOW LEVEL CHAN B2 TRIP	4. NBI-LIS-101D	

PROBABLE CAUSES

- Loss of feedwater.
- Loss of coolant accident.
- Main steam isolation.

REFERENCES

- Technical Specifications LCO 3.3.1.1, Reactor Protection System (RPS) Instrumentation.
- General Operating Procedure 2.1.5, Reactor Scram.
- General Operating Procedure 2.1.22, Recovering From a Group Isolation.

10. GROUP 7 ISOLATION

10.1 Upon 1/2 Group 7 Isolation or RPS power supply failure, ensure following occurs:

10.1.1 If Logic A trips, RR-AO-741, INBD ISOL VLV, closes.

10.1.2 If Logic B trips, RR-AO-740, OUTBD ISOL VLV, closes.

10.2 Upon full Group 7 Isolation, ensure following valves have closed (Panel 9-4):

10.2.1 RR-AO-740, OUTBD ISOL VLV, if PASS sample not in-progress.

10.2.2 RR-AO-741, INBD ISOL VLV, if PASS sample not in-progress.

10.3 Determine isolation cause:

ISOLATION	ALLOWABLE VALUE
Low Reactor Water Level	≥ -113"
Main Steam Line High Radiation	≤ 3 x normal full power background
RPS Power Supply Failure	

Examination Outline Cross-Reference	Level	RO
295005 (APE 5) Main Turbine Generator Trip / 3 Ability to operate and/or monitor the following as they apply to MAIN TURBINE GENERATOR TRIP: AA1.01 Recirculation system: Plant-Specific	Tier#	1
	Group#	1
	K/A #	295005 AA1.01
	Rating	3.1
	Revision	0
Revision Statement:		

Question 58

The plant is at 60% power.

Reactor Recirc pump drive motor breakers 1CN and 1DS are closed with each pump at 57% speed.

A main generator load reject occurs.

Reactor pressure peaks at 1050 psig.

What is the status of RR Pumps A and B two minutes later?

A. A is OFF
B is running at ~57% speed

B. A is OFF
B is running at ~22% speed

C. A is running at ~57% speed
B is OFF

D. A is running at ~22% speed
B is OFF

Answer: B
Explanation: Breaker 1CN powers RR Pump A MG and is supplied by NSST, which is supplied by the main generator. 1CN trips when the generator trips on load reject. 1DS powers RR Pump B MG and is supplied by SSST, which is not affected by the load reject. The load reject results in a turbine trip, which causes a scram on TSV closure/ TCV fast closure above ~28% power. RVLCS initiates setpoint setdown due to the scram and reduces FW demand to <20%. When FW flow goes <20%, the operating RR Pump (B) runs back to minimum speed, ~22%, which takes ~1 minute.

Distracters:
Answer A is plausible because RR Pump B is initially at 57% speed, and at higher power levels, a load reject may cause ATWS RPT to initiate (1060 psig reactor pressure), which would trip RR MG field breakers and prevent a RR runback. It is wrong because ATWS RPT does not initiate, since peak pressure is given as 1050 psig, below the RPT setpoint. FW flow reduces below 20% following a scram. That causes RR Pump B to runback to ~22%.

Answer C is plausible because one RR pump is powered from the NSST and one is powered from the SSST, and because of the same reason stated for distractor A. It is wrong because RR Pump B MG is supplied from SSST, so it remains running, and RR Pump A MG is supplied from the NSST, which loses power when the generator trips. It is also wrong for the reason stated for distractor A.

Answer D is plausible because one RR pump is powered from the NSST and one is powered from the SSST. It is wrong because RR Pump B MG is supplied from SSST, so it remains running, and RR Pump A MG is supplied from the NSST, which loses power when the generator trips.

Technical References: Lesson plan COR002-22-02 [Reactor Recirculation System](Rev 35)

References to be provided to applicants during exam: none

Learning Objective: COR002-22-02 OBJ LO-4e: Describe the interrelationships between the Reactor Recirculation system or the Recirculation Flow Control system and the following: Main Turbine Generator trip

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(6)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA Applicability:		

Lesson Number: COR002-22-02	Revision: 35

Fig 2 LO-01i, LO-05g SO-02e

G. Recirculation Motor Generator (MG) Sets

1. The Recirc MG sets supply the electrical power used to operate the Recirc pumps. The MG sets will also, based on control signals from the Flow Control system, control the speed at which the Recirc pump is operated.

2. The Recirc MG sets are made up of the following components:

   a. drive motor

   b. generator

   c. exciter

   d. voltage regulator

   e. MG oil system

   f. fluid coupler

   g. tachometer

SO-02f Fig 10

3. The drive motor provides the driving force to operate the exciter and, via the fluid coupler, the generator end of the MG set.

LO-08e, LO-15b

The drive motor is a 4160 VAC, 7000 hp, 6 pole, 1190 rpm, induction motor with a maximum current of 850 amps at 60 Hz (which corresponds to the maximum generator output frequency of 57.5 Hz). The maximum winding temperature for the drive motor is 230°F.

The Recirculation MG set (1A and 1B) drive motors are "hard wired" directly to the 4160 VAC switchgear 1C and 1D, respectively. This means each drive motor has two supply breakers. Shutting either breaker to the respective 4160 VAC bus will energize that RRMG set motor, causing motor amps and temperature to rise.

   a. 4160 VAC switchgear 1C is powered from either the Normal Station Service Transformer, via breaker 1CN, or from the Startup Station Service Transformer, via breaker 1CS.

   b. 4160 VAC switchgear 1D is powered from either the Normal Station Service Transformer, via breaker 1DN, or from the Startup Station Service Transformer, via breaker 1DS.

le 1

The drive motor breakers (1CN or 1CS and 1DN or 1DS) provide trip protection not only to their respective buses and MG drive motors, but also to the Recirc pumps themselves. The conditions that will cause the drive motor breakers to trip are listed in Table 1.

UNDERVOLTAGE trip relays for 1C and 1D 4160V bus.

Lesson Number: COR002-22-02	Revision: 35

In the event that both seals fail, a maximum of 60 gpm leakage would occur. The maximum leakage is limited by the throttling produced by the flow restricting bushing. Both flow switches will initiate a "high" alarm.

The plugging of the No. 1 pressure reducing cell passage would result in a reduction in the No. 2 seal pressure and a flow switch would activate a "Recirc PUMP A(B) SEAL TROUBLE" (LOW SEAL STAGING FLOW) alarm.

The plugging of the No. 2 pressure reducing cell passage would cause the pressure in the No. 2 seal cavity to increase and a flow switch will activate a low seal staging flow alarm.

LO-06e If the plant is just being started up, and there is a seal problem, the seal staging valve line up should be rechecked for proper lineup.

SO-07a 3. Local Scoop Tube Operation

a. When the Reactor Mode switch is in START/HOT STBY or RUN, local scoop tube operation shall be performed by a Licensed Operator.

LO-08a b. To obtain local control the scoop tube is locked out by pressing the SCOOP TUBE LOCKOUT button on 9-4 panel. The local manual engage push button is pressed. The hand crank is turned (counter clockwise to raise speed) (clockwise to lower speed).

c. To return control of the scoop tube to the Control Room, the SPEED CONTROL RRFC-SIC-16A(B). The scoop tube lockout is reset by the Control Room operator adjusts RRFC-SIC-16A(B) slowly adjust (parameter S) until S and L alarm lights are off, verify parameter V is within 2.0 of parameter P value. The scoop tube lockout can then be reset and the Control Room operator has control of the RRMG set.

LO-04e 4. Main Turbine Generator Trip

On a Main Turbine trip from a normal operating condition, 4160 VAC 1CN and 1DN will trip open, tripping the respective Recirc MG set. The turbine trip would also lead to a reduction in feed flow to less than 20% which will cause the operating Recirc pump to run back to minimum.

LO-04g 5. Loss of Plant Air

Plant Air is the motive force for the RRMG Set Ventilation isolation valves. On a loss of Plant Air, their accumulators start to bleed down. Even though these accumulators have check valves to reduce their leak rates, eventually they would depressurize and the isolation valves would become inoperable. If these valves became inop. in the open seen, the controller sends out a signal to change the output. The faster the Pulser Knob is spun, the faster the output will change. The rate of change is limited within the logic of the controller. It is not the number of revolutions that the knob is turned that determines how far the output will change, it is how fast the knob is turned. In order for the Pulser Knob to operate the "S" display must be selected, using the Display Pushbutton. Any other display being selected will prevent the Pulser Knob from operating.

Fig 14a

d. Controller Logic

1) Speed Limiters

a) The Speed limiters within the controller perform three functions:

(1) The 22% Limiter (TSW 1) restricts Recirc pump speed during low power operations or with the pump discharge valve closed.

(2) The 45% Limiter (TSW 2) reduce reactor power under conditions where RPV water level is lowering due to possible FW malfunction.

(3) The 40% Limiter (TSW3) generates a control signal, on pump start up.

LO-01l, 13b, 10l
Fig 14c

b) The 22% Speed limiter will limit the speed of its respective pump to a maximum of 22% if either of the following conditions exist:

(1) If the pump's discharge valve is less than 10% from full open. When the discharge valve is not full open, increasing the pump speed above 22%, could cause pump or pump seal damage due to back pressure oscillations developed by the pump discharge head.

LO 07e, 10a, 13b

(2) If feedwater flow to the reactor is less than 20% of rated, increasing pump speed could cause pump cavitation since the necessary inlet subcooling effect that feedwater has on the downcomer annulus would be lacking. The reduced inlet subcooling would reduce the Net Positive Suction Head (NPSH) felt at the suction of the Recirc pump.

Lesson Number: COR002-22-02	Revision: 35

LO-10n
LO-13d
LO-05a

TABLE 2

Recirc MG Generator Field Breaker Trips

1. Low Reactor Water Level $\geq$-42" (ARI trip; Tech Spec Allowable Value, actual setpoint -33.43")
2. High Reactor Pressure $\leq$1072 psig (ARI trip; Tech Spec Allowable Value, actual setpoint 1060 psig)
3. Loss of Generator Field Voltage (Bypassed for 10 seconds during pump start.)
4. Generator Lockout (see Table 3)

Lesson Number: COR002-22-02	Revision: 35

The 22% limiter is bypassed whenever the discharge valve is fully open and feedwater flow is greater than 20% of rated. The limiter will reset the speed demand signal (S) to the runback signal if the current speed demand signal is greater than the runback signal.

The 22% runback automatically resets when the runback condition clears.

LO-01k, 13c, 10l
Fig 14d

c) RR runback towards 45% stops when the condition causing the runback is no longer true and no other 45% runback conditions exist.

If both Reactor Recirculation Pumps are running and not locked out, RR pumps run back towards 45% speed if any of the following conditions are met:

(1) Total steam flow > 8.25 Mlbm/hr concurrent with a condensate pump low discharge header pressure < 110 psig and a condensate pump tripped.

(2) Total steam flow > 8.25 Mlbm/hr concurrent with a condensate booster pump low discharge header pressure < 450 psig and a condensate booster pump tripped.

(3) Total steam flow > 8.25 Mlbm/hr with at least both RFP suction pressures < 350 psig.

(4) Total steam flow > 9 Mlbm/hr with at least 1 RFP tripped/flow < 1 Mlbm/hr and selected reactor water level < 27.5".

The limiter will reset the speed demand signal (S) to the runback signal if the current speed demand signal is greater than the runback signal.

Fig 14b, LO-01j, 10c

d) The 40% Speed limiter generates a 40% speed signal on a Recirc pump start up to provide sufficient torque to "break away" the pump (start rotation from an at rest condition). This speed signal will be removed from the circuit when the field breaker for that MG set is closed.

Examination Outline Cross-Reference	Level	RO
239001 (SF3, SF4 MRSS) Main and Reheat Steam Knowledge of the effect that a loss or malfunction of the MAIN AND REHEAT STEAM SYSTEM will have on following: K3.05 Condenser air removal	Tier#	2
	Group#	2
	K/A #	239001
	Rating	2.8
	Revision	0
Revision Statement:		

Question 59

A spurious Group 1 isolation occurs at 100% power.

Which stage(s) of air ejectors lose(s) driving steam as a direct result of the Group 1 isolation?

A. 1^{st} stage, ONLY

B. 3^{rd} stage, ONLY

C. 1^{st} AND 2^{nd} stages

D. 2^{nd} AND 3^{rd} stages

Answer: C

Explanation:
This question tests knowledge of the direct effect of loss of main steam to the condenser air removal system. Each SJAE train contains two first stages and two second stages. One first stage and one second stage in an SJAE is capable of evacuating one shell of the Main Condenser. The suction piping to the SJAEs is arranged so either SJAE could evacuate either or both shells of the Main Condenser. Normally one first stage and both second stages from each SJAE is in service. 1^{st} and 2nd stage SJAEs are supplied steam from the main steam equalizing header. Only a Group 1 isolation (MSIVs and MSL Drains) isolates the equalizing header, and thus 1^{st} and 2^{nd} stage air ejectors, from the RPV.

The first two processes of the AOG system, compression and dilution of the stream, are accomplished through the addition of Main Steam from the third stage ejectors and sonic nozzles in both AOG trains. This compression and dilution raises the total stream pressure and lowers the hydrogen concentration below its flammability limit of 4% by volume. The 3rd Stage Air Ejectors are supplied Main Steam from the “C” Main Steam Line upstream of the inboard isolation valve (MS-AO-80C) via the HPCI steam supply line and two RHR motor operated valves (RHR-MO-920 and

RHR-MO-921). A Group 2 isolation closes RHR-MO-920 and RHR-MO-921, which would isolate main steam to AOG 3rd stage air ejectors. A Group 4 isolation would close HPCI-MO-15 and HPCI-MO-16, which would indirectly isolate main steam to AOG 3rd stage air ejectors.

Distracters:
Answer A is plausible because one stage of air ejectors is supplied through a different path than the other two stages. The examinee who does not know the main steam piping arrangement or the air ejector arrangement may choose this answer. It is wrong because 2nd^{t} stage air ejectors are also supplied by main steam from the equalizing header, which would be lost if Group 1 valves isolated.

Answer B is plausible because the 3rd stage air ejectors are supplied through a different path than the 1st and 2nd stages. An examinee who confuses the steam supply for the 3rd stage air ejectors with that of the 1st and 2nd stages may choose this answer. It is wrong because 3rd stage air ejectors are supplied Main Steam from the "C" Main Steam Line upstream of the inboard isolation valve (MS-AO-80C) via the HPCI steam supply line, not from the equalizing header.

Answer D is plausible because two stages of air ejectors are supplied by a common path, the equalizing header. An examinee who confuses the pairing of air ejectors may chose this answer. It is wrong because 1st and 2nd stage air ejectors lose their steam supply following a Group 1 isolation, but the 3rd stage air ejectors do not.

Technical References: lesson plan COR002-14-02 [Ops Main Steam](Rev 30), lesson plan COR001-16-01 [Ops Off Gas](Rev 35), lesson plan COR002-11-02 [Ops High Pressure Coolant Injection](Rev 38)

References to be provided to applicants during exam: none

Learning Objective: COR002-14-02 Obj LO-3d, Describe the interrelationships between the Main Steam system and the following: Off Gas and Condenser Air Removal system

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(4),(7)	
Level of Difficulty:	2	
SRO Only Justification:	N/A	

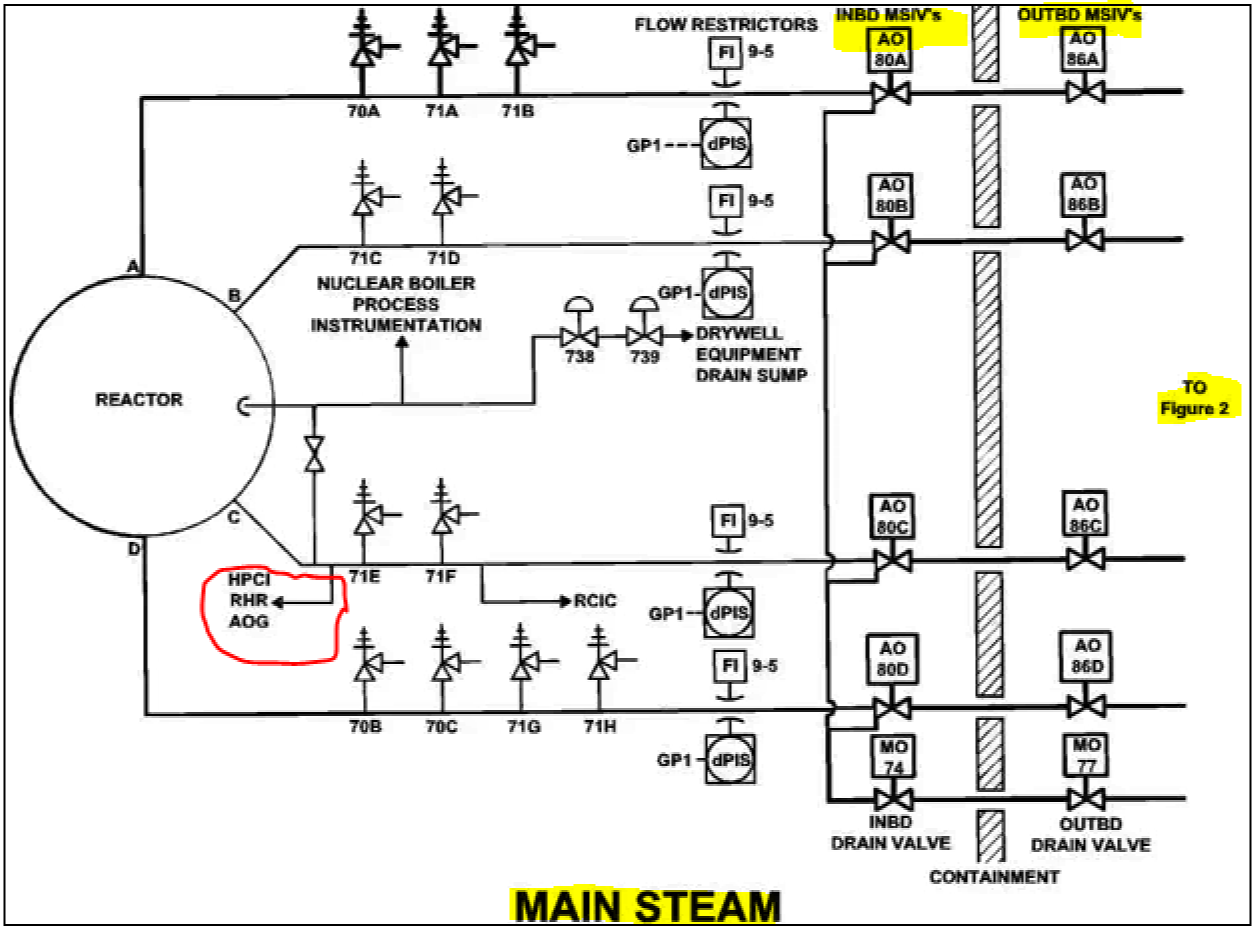
PSA Applicability:
N/A

Fig. 1	A.	Steam Jet Air Ejectors (SJAE)
LO-01b; 06a; 11a SO-02a; 10a;	1.	The SJAEs remove all noncondensible gases from the condensers, including air in-leakage and dissociation products originating in the reactor and exhausts them to the Off Gas holdup volume.
	2.	Each of the two SJAEs is a full capacity unit. Each SJAE contains two first stages and two second stages. One first stage and one second stage in an SJAE is capable of evacuating one shell of the Main Condenser. The suction piping to the SJAEs is arranged so either SJAE could evacuate either or both shells of the Main Condenser. Normally one first stage and both second stages from each SJAE is in service.
LO-06f SO-10f	3.	The SJAEs use Main Steam (from the equalizing header) reduced in pressure from approximately 950 psig to 300 psig as their driving medium.

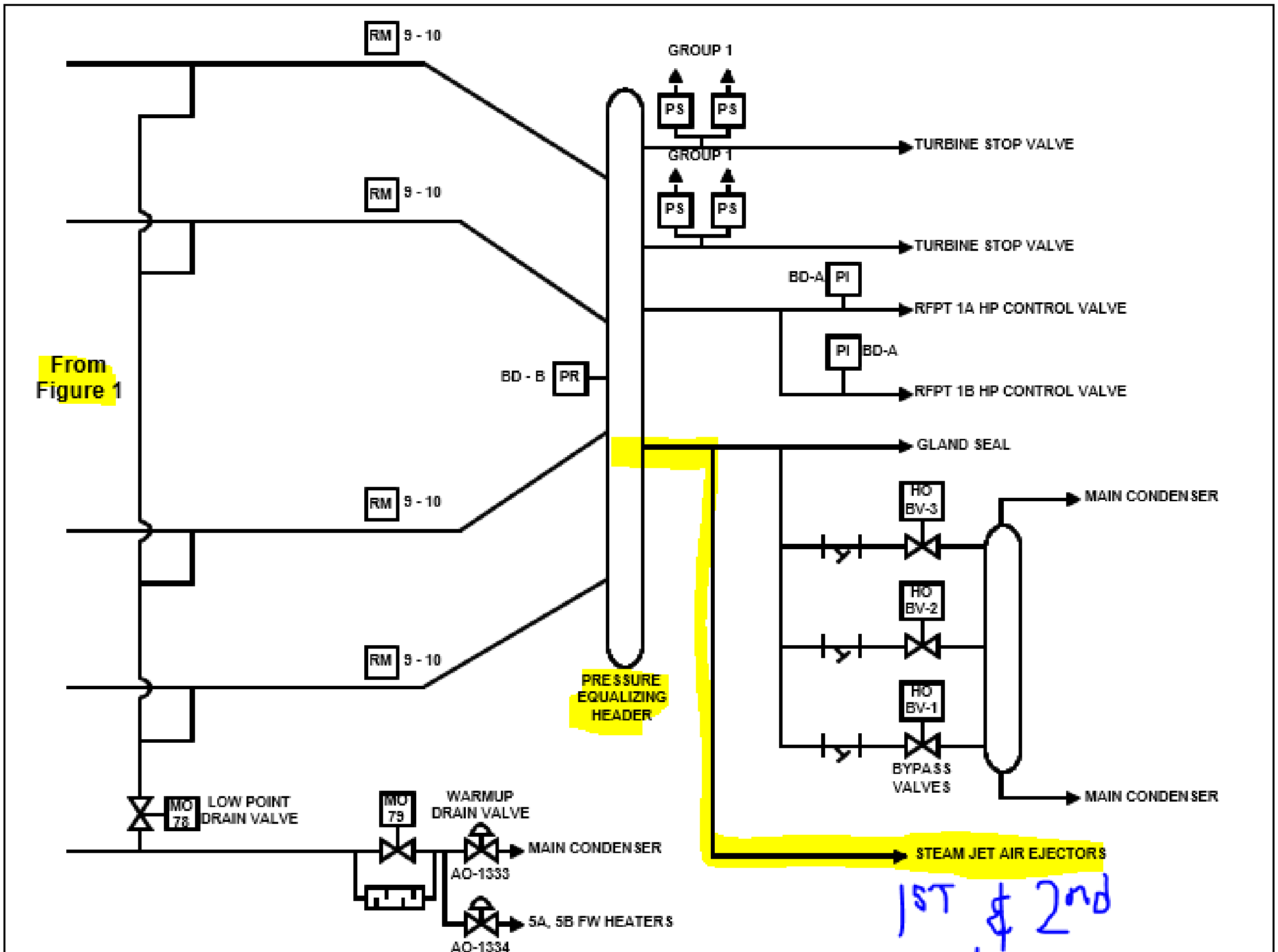
Lesson Number: COR001-16-01	**Revision:** 35

LO-06f; 13b, f SO-10f	1.	The Third Stage Air Ejectors are supplied Main Steam from the "C" Main Steam Line upstream of the inboard isolation valve (MS-AO-80C). This tap supplies steam to the HPCI turbine and the AOG Third Stage Air Ejectors.
	2.	The steam supply to AOG has two (2) motor operated valves (RHR-MO-920 and RHR-MO-921) in its main stream. These valves receive a close signal on a Group 2 isolation signal, Area Space temperature, or No Condensate pumps running. A half Group 2 isolation will result in a valve closure of RHR-MO-920 or RHR-MO-921.
	3.	A bypass valve (RHR-MO-1485) around the 921 valve allows for pressurization of the AOG system on initial startup. Once 921 is open, the operator shuts 1485.
	4.	There are two manual isolation valves in the HPCI steam supply line, downstream of the tap off for steam supply to AOG. These valves are for the isolation and maintenance of HPCI, without taking AOG out of service.
Fig. 2 LO-01g SO-02f	J.	Third Stage Ejectors (SJAE)
	1.	The third stage ejectors compress the Off Gas stream, raising the pressure of the stream to the required system inlet pressure,

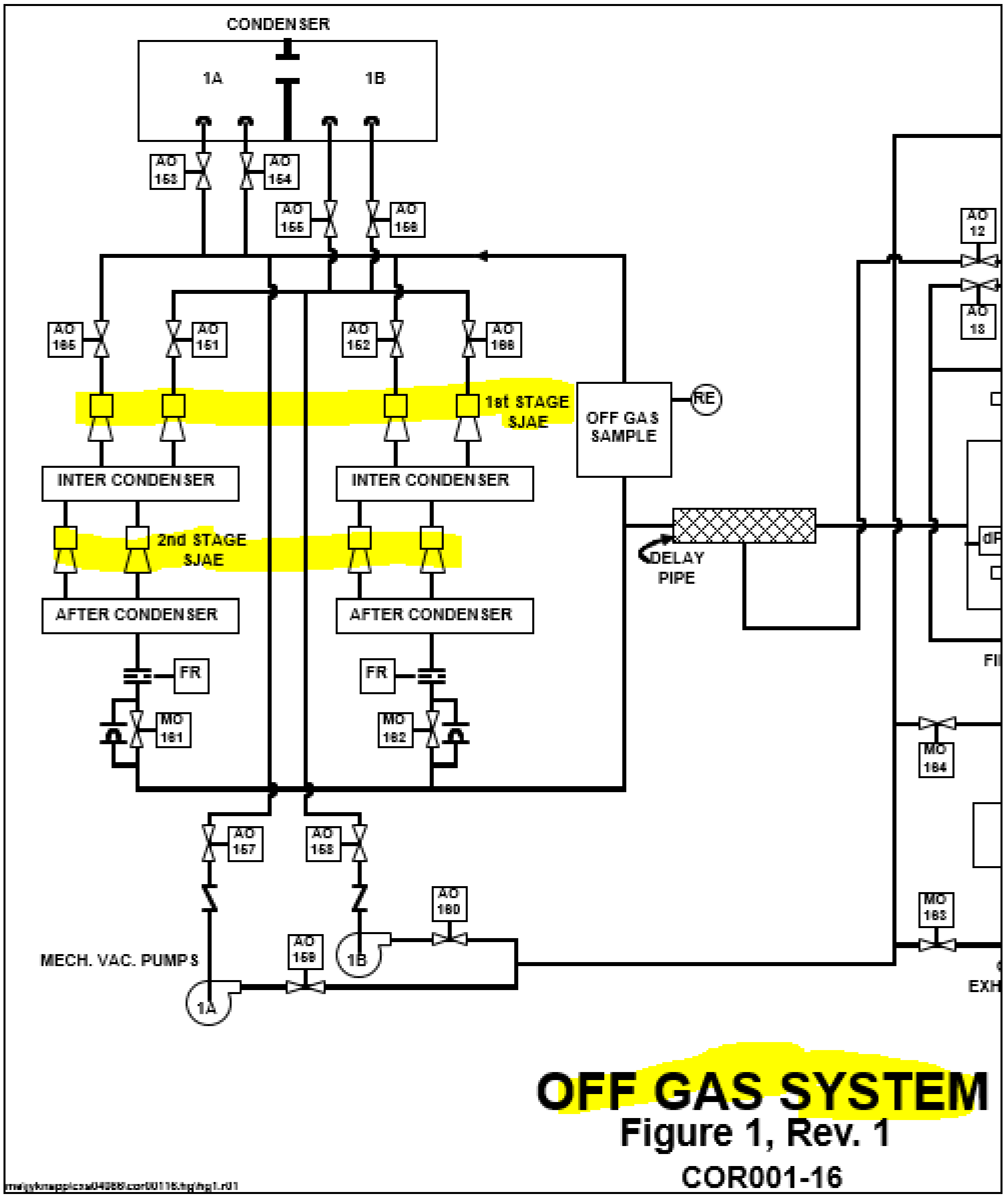
	thereby creating the motive force for the Off Gas stream throughout the AOG system.
LO-08a	Additionally, the ejectors provide initial dilution and heating of the incoming gas stream prior to its entry into the preheater. Dilution of the Off Gas stream is required to reduce the hydrogen concentration below the flammability limit of 4%.

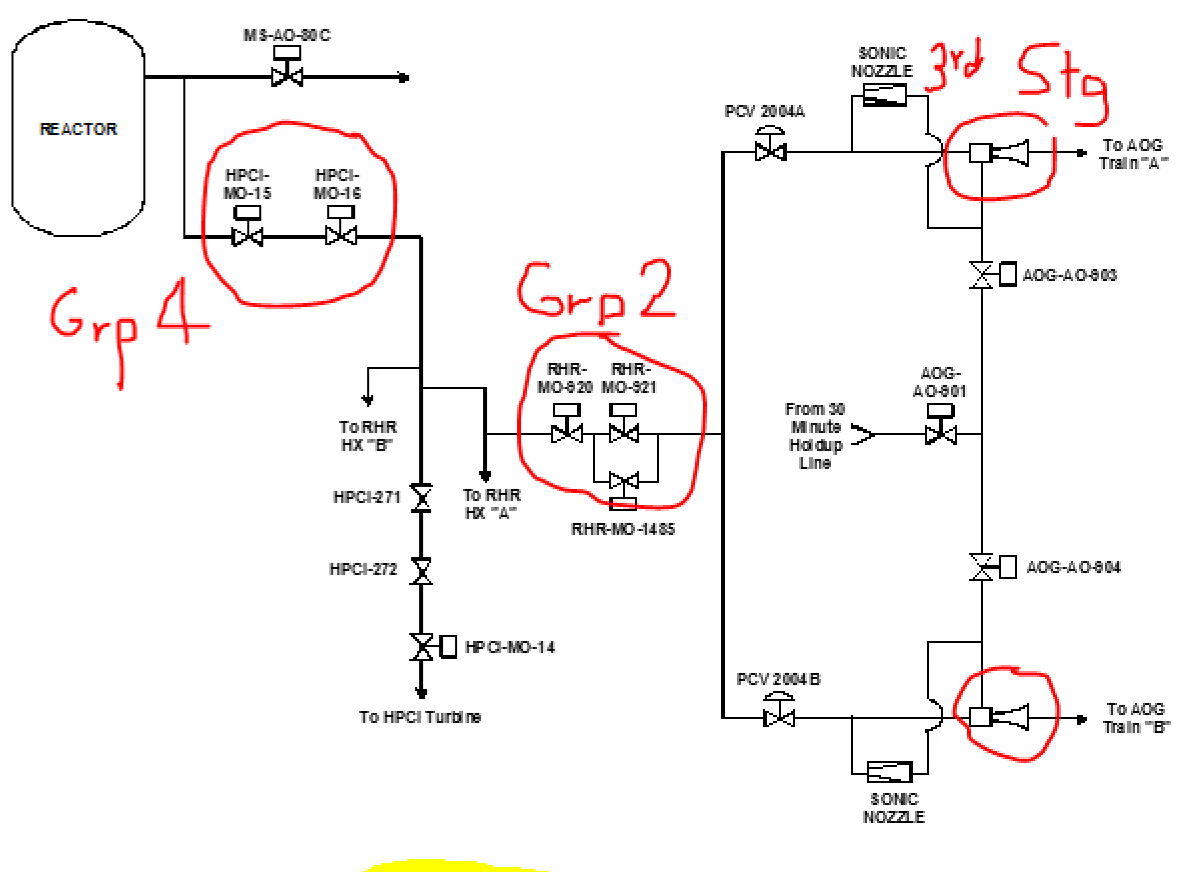


FLOW RESTRICTORS
INBD MSIV's
OUTBD MSIV's
AO 80A
AO 86A
FI 9-5
70A
71A
71B
GP1
dPIS
AO 80B
AO 86B
71C
71D
NUCLEAR BOILER PROCESS INSTRUMENTATION
A
B
C
D
REACTOR
738
739
DRYWELL EQUIPMENT DRAIN SUMP
TO Figure 2
AO 80C
AO 86C
71E
71F
HPCI
RHR
AOG
RCIC
AO 80D
AO 86D
70B
70C
71G
71H
MO 74
MO 77
INBD DRAIN VALVE
OUTBD DRAIN VALVE
CONTAINMENT
MAIN STEAM



MAIN STEAM
Figure 2, Rev. 10
COR002-14


CONDENSER
1A
1B
AO 153
AO 154
AO 155
AO 156
AO 165
AO 151
AO 152
AO 166
1st STAGE SJAE
OFF GAS SAMPLE
RE
INTER CONDENSER
INTER CONDENSER
2nd STAGE SJAE
AFTER CONDENSER
AFTER CONDENSER
FR
FR
MO 161
MO 162
DELAY PIPE
AO 12
AO 13
MO 164
MO 163
AO 157
AO 158
AO 160
AO 159
MECH. VAC. PUMPS
1A
1B
OFF GAS SYSTEM
Figure 1, Rev. 1
COR001-16



AOG STEAM SUPPLY SYSTEM
Figure 2, Rev. 2
COR001-16

Lesson Number: COR002-14-02	Revision: 30

Fig 1, 2 E. Basic System Operation

The Main Steam system conducts steam from the reactor vessel, via four steam lines, through the Primary Containment to a pressure equalizing header. Each steam line has two, normally open, Main Steam Isolation Valves (MSIVs), one inside and one outside the Primary Containment. Systems that may be needed in case of a reactor isolation (HPCI and RCIC) are supplied from upstream of the MSIVs. The remaining systems and components that use reactor steam are supplied from the pressure equalizing header.

Lesson Number: COR002-14-02	Revision: 30

LO-02a J. Plant Electrical

1. 125V DC - Supplies power to MS-77 (steam line drain valve) and MSIV DC solenoids and controls.

LO-05d 2. 120V AC - Supplies power to MSIV AC solenoids and controls (RPSPP1A supplies inboard MSIVs and RPSPP1B supplies outboard MSIVs).

LO-02b 3. MCC-R - Supplies 460 VAC power to MS-74, 78, 79 (steam line drain valves).

LO-03s K. RHR System

Main Steam supplies the Augmented Off Gas System through RHR system valves RHR-920MV and RHR-921MV. These valves receive a close signal on a Group 2 isolation signal, Area Space temperature, or No Condensate pumps running. A half Group 2 isolation will result in a valve closure of RHR-MO-920 or RHR-MO-921.

SO-07d L. Augmented Off-Gas (AOG)

Upon receipt of low steam supply pressure of 850 psig downstream of RHR-921, or low dilution steam pressure of 425 psig at the inlet of the third stage SJAE, AOG will isolate causing OG-254 to open and AOG-901 to close.

Lesson Number: COR002-11-02	Revision: 38

2. When a HPCI trip signal is received, the following events automatically occur:

LO-12c

a. The turbine stop and control valves close.
b. Pump minimum flow valve (MO-25) closes.
c. If trip is due to high reactor level, Steam Supply Block valve (MO-14), and Exhaust Line Drain valves (AO-70 and AO-71) also close.

H. System Isolation (GRP 4)

LO-05j
LO-08b
LO-12b

1. HPCI system isolation signals are:

a. Steam supply line high flow #250% of rated with a #6 sec time delay

b. Steam line high space temperature # 195EF

c. Low steam supply pressure 107 ≤ P ≤150 psig. (Trip must isolate >107 psig to meet isolation Tech Spec, but < 150 psig based upon HPCI requirement to be operable prior to exceeding 150 psig).

d. Manual isolation trips Logic B portion of Group 4 isolation from Panel 9-3 if an initiation signal is present.

2. When a HPCI isolation signal is received, the following events automatically occur:

LO-10p

a. Steam isolation valves MO-15 and MO-16 closes;

b. Exhaust line drain valves AO-70 and AO-71 to the gland seal condenser close;

Examination Outline Cross-Reference	Level	RO
295019 (APE 19) Partial or Complete Loss of Instrument Air / 8 Ability to determine and/or interpret the following as they apply to PARTIAL OR COMPLETE LOSS OF INSTRUMENT AIR: AA2.01 Instrument air system pressure	Tier#	1
	Group#	1
	K/A #	295019 AA2.01
	Rating	3.5
	Revision	0
Revision Statement:		

Question 60

Station Air Compressors (SAC) are aligned as follows:

- SAC 1A 1st Backup
- SAC 1B Lead
- SAC 1C 2nd Backup

A leak has occurred on the instrument air supply header.

Instrument Air supply header pressure has fallen to 92 psig and has stabilized.

480V Bus 1G is de-energized.

Which Station Air Compressor(s) is/are running loaded NOW?

A. 1A, only

B. 1B, only

C. 1A and 1B

D. 1A and 1C

Answer: A
Explanation: This is a modified version of 3-2017 ILT NRC Q#52. It was modified by replacing high lube oil temperature with loss of 4160V Bus 1G as an intitial condition. An entry condition for procedure 5.2AIR is IA header pressure below the green band on IA-PI-66 on panel A. The bottom of the green band is 95 psig, so 5.2AIR entry is

required. The operator must interpret IA pressure to verify automatic actions occur. The lead SAC, 1B, is set to load between 100 to 110 psig. The 1st Backup SAC, 1A, is set to auto start at 93 psig and load between 93 to 99 psig. The 2nd Backup SAC, 1C, is set to auto start at 90 psig and load between 90 to 97 psig. Therefore, for IA pressure of 92 psig, only SAC 1A and 1B have a demand to be running loaded, since 92 psig is above the auto start and loading range of the 2nd backup compressor, SAC C.

480V bus 1G supplies SAC B and is de-energized, so, SAC B is not running. 480V bus 1F supplies SAC A and is not affected, so SAC A is running.

Therefore, only SAC 1A is running loaded.

Distracters:
Answer B is plausible because SAC A is also supplied by a 480V AC bus. It is wrong because 480V bus 1F supplies SAC A and is not affected, so SAC A is running, and 480V bus 1G supplies SAC B and is de-energized, so, SAC B is not running.

Answer C is plausible because IA pressure is below the setpoint for the 1st backup, SAC A, to be running. It is wrong because SAC B is not running due to 480V bus 1G being de-energized.

Answer D is plausible because each SAC will operate loaded for different IA pressure ranges. The examinee who believes all SACs have a demand to operate loaded at 92 psig IA pressure but recognizes 480V bus 1G supplies SAC B will choose this answer. It is wrong because SAC 1C would not be running loaded, since IA pressure, 92 psig, has not yet lowered to its auto start setting of 90 psig.

Technical References: Procedures 5.2AIR [Loss of Instrument Air](Rev 22), 2.2.59 [Plant Air System](Rev 76), lesson plan COR001-17-01 [Ops Plant Air](Rev 33)

References to be provided to applicants during exam: none

Learning Objective: INT032-01-36 EO-M: Given plant condition(s), determine from memory any automatic actions listed in the applicable Abnormal/Emergency Procedure(s) which will occur due to the event(s); COR0011701 Obj. LO-05b, Describe the Plant Air system design features and/or interlocks that provide for the following: Air compressor sequence control; 04a, State the electrical power supplies to the following: Air Compressors

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	3-2017 ILT NRC Q#52
	New	

Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(4)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA applicability:		
N/A		

Question 52

Station Air Compressors (SAC) are aligned as follows:

- SAC 1A → 1st Backup
- SAC 1B → Lead
- SAC 1C → 2nd Backup

A leak has occurred on the instrument air supply header.

Instrument Air supply header pressure has fallen to 92 psig and has stabilized.

SAC 1B Lube Oil temperature is 150°F.

Which Station Air Compressor(s) is/are running loaded NOW?

A. 1A, only

B. 1B, only

C. 1A and 1B

D. 1A and 1C

Answer: C. 1A and 1B

CNS OPERATIONS MANUAL EMERGENCY PROCEDURE 5.2AIR LOSS OF INSTRUMENT AIR	USE: CONTINUOUS QUALITY: QAPD RELATED EFFECTIVE: 8/28/19 APPROVAL: ITR-RDM OWNER: AOM-SUPPORT DEPARTMENT: OPS

Scram Actions

1. ENTRY CONDITIONS

1.1 INSTRUMENT AIR PRESSURE below green band and does not recover back into green band.

1.2 SERVICE AIR PRESSURE below green band and does not recover back into green band.

2. AUTOMATIC ACTIONS

2.1 1st Standby SACs loads when system pressure 93 to 99 psi.

2.2 2nd Standby SACs loads when system pressure 90 to 97 psi.

2.3 SA-PCV-609, SERVICE AIR SYSTEM ISOLATION, closes when service air pressure < 77 psig.

3. IMMEDIATE OPERATOR ACTIONS

3.1 None.

4. SUBSEQUENT OPERATOR ACTIONS

4.1 Record current time and date. Time/Date: ________/__________

4.2 IF more than one rod drifting, THEN SCRAM and concurrently enter Procedure 2.1.5.

4.3 IF air drying/filtering components at fault, THEN perform following:

4.3.1 Open SA-MO-81, SA TO IA CROSSTIE (PANEL A).

4.3.2 Place standby dryer and filters in service per Procedure 2.2.59.

4.3.3 If necessary, manually bypass any obstructed component(s).

4.3.4 WHEN dryer and filter flow returned to service, THEN close SA-MO-81.

Scram Actions

4.4 IF SACs tripped, THEN have Operator locally reset per Procedure 2.2.59.

4.5 Make following announcement twice:

"All personnel using breathing equipment supplied by plant air move to an area with a clean atmosphere."

Lesson Number: COR001-17-01	Revision: 33

will restart when power restored, affected breaker locally reset and SAC locally started.

c. If switch in MCR is in OFF prior to loss of power, the compressor will respond as follows: Once power is restored, the switch can be taken to AUTO, the breaker on the 480 volt switchgear will close, and the air compressor will start and respond to decreasing air pressure. (Reference 5.1 Weather).

8. Electric power to the air compressors is supplied as follows:

   a. Compressor 1A from 480 VAC Switchgear 1F.
   b. Compressor 1B from 480 VAC Switchgear 1G.
   c. Compressor 1C from 480 VAC Switchgear 1B.

9. Cooling water is admitted to each compressor through a pressure control valve and a solenoid inlet valve. The pressure control valve, set at 65 psig, protects the compressor cooling system from over-pressurization. The solenoid inlet valve opens when the air compressor is running. This valve receives its control power from the compressor's control power. A manually operated bypass valve is provided to allow bypassing the solenoid.

fig 7

10. The compressor discharge pressure is controlled by the operation of an unloader valve which functions to recirculate the air discharged by the compressor back to their suction. The compressor unloading valves are controlled by Elektronikon.

LO-05a; 06a
LO-07b; 11c

11. Air Compressor Trips

   a. Compressors will trip, generate a local shutdown alarm and Control Room compressor trip annunciator from any of the following:

      1) 1st Stage discharge air temperature high ≥ 428ºF for > 1 sec.

      2) 2nd Stage inlet air temperature high ≥ 158ºF for > 1 sec.

      3) 2nd Stage discharge air temperature high ≥ 428ºF for > 1 sec.

      4) Compressor High outlet pressure ≥ 217.5 psig for > 1 sec.

ATTACHMENT 3 INFORMATION SHEET

TABLE 1 - SAC INTERLOCKS AND SETPOINTS

Individual SAC Parameters	Setpoint	Note
Loading Pressure 1	B:100, A:93, C:90	
Unloading Pressure 1	B:110, A:99, C:97	
Loading Pressure 2	Not Used	B:100, A:93, C:90
Unloading Pressure 2	Not Used	B:110, A:99, C:97
Y Time	10 S	
Load Delay	10 S	
Nr Starts Day	Variable	Number of Starts/Day is 0 for Lead SAC; 6 for 1st Backup SAC; 6 for 2nd Backup SAC
Minimum Stop Time	20 S	
Programmed Stop Time	3 S	
Communication Time Out	20 S	
Drain Duration	10 S	
Restart Delay (ARAVF)	3 S	
Power Recover Time (ARAVF)	∞ ! S	
Individual SAC Configuration	**Setpoint**	**Note**
Language in Use	English	
Time	0:00	
Date	MM/DD/YY	
Date Format	MM/DD/YY	
Pressure Unit	PSI	
Temperature Unit	°F	
Vibration Unit	MILS	
Level Unit	Inch	
Flow Unit	CFM	
Volume Unit	Gallon	
Start Mode	Y-D	
Automatic Restart (ARAVF)	Activated - Infinite	
Password	Not Activated	
MCC	Not Activated	
Digital Pressure Band	Not Activated	
CCM	LAN	
Node ID	Variable	B:1, C:2, A:3

Examination Outline Cross-Reference	Level	RO
216000 (SF7 NBI) Nuclear Boiler Instrumentation Ability to (a) predict the impacts of the following on the NUCLEAR BOILER INSTRUMENTATION ; and (b) based on those predictions, use procedures to correct, control, or mitigate the consequences of those abnormal conditions or operations: A2.09 Jet pump flow: Design-Specific	**Tier#**	2
	Group#	2
	K/A #	216000 A2.09
	Rating	3.1
	Revision	0
Revision Statement:		

Question 61

Which one of the following completes the statements below regarding the effect of jet pump flow on Fuel Zone level indication?

Jet pump flow causes **Fuel Zone** level to indicate __(1)___ than actual.

Operations Instruction #8 [Guidelines for Successful Transient Mitigation] requires the operator to evaluate changes in ____(2)_____ injection flow because making sudden changes in flow rate will cause a large change in Fuel Zone level indication due to effects on jet pump flow.

A. (1) Higher
(2) LPCI

B. (1) Higher
(2) Core Spray

C. (1) Lower
(2) LPCI

D. (1) Lower
(2) Core Spray

Answer: A
Explanation: This question tests application of Operations Instruction #8 direction regarding the effects of the design of Fuel Zone level instrumentation, specifically variable leg arrangement, with respect to internal RR Jet Pumps. Fuel zone instruments tap off jet pump #6 and 16 lower taps. They are only accurate with no jet pump flow. The positive dynamic head at the variable tap resulting from the jet pump flow causes the Fuel Zone differential pressure transmitter to indicate a high indicated fuel zone level

relative to actual level, since it senses higher than actual pressure at the instrument variable leg tap. RHR (LPCI) injects into Reactor Recirc discharge piping and into jet pump drive flow nozzles, resulting in flow through the jet pumps and a higher indicated level than actual level. If RHR flow is abruptly stopped, indicated Fuel Zone level will take a step change downward. OI#8 directs the operator to take this into consideration when adjusting LPCI injection to maintain the prescribed level band.

Distracters:
Answer B part 1 is correct. Part 2 is plausible because Core Spray reduces the core exit pressure. An Examinee may believe this affects Fuel Zone indication due to a manometer affect. It is wrong because OI#8 states when using Core Spray or condensate for injection, fuel zone indication is not affected by injection rate, and the subject phenomenon and direction in OI#8 relates to LPCI.

Answer C part 1 is plausible because Wide Range level instruments are also affected by Jet Pump flow, but in the opposite way, Entrained flow into the jet pumps in the annulus region outside the core shroud passes the lower tap of the Wide Range instruments and has a significant velocity head and some friction loss which reduces the pressure on the Wide Range variable leg to the differential pressure (level) instrument, resulting in an indicated level lower than actual. It is wrong because Fuel Zone variable tap is in the jet pump nozzle and senses higher pressure when jet pump flow exists, so indicated level lowers when jet pump flow is reduced. Part 2 is correct.

Answer D part 1 is plausible and wrong for the reason stated for distractor C. Part 2 is plausible and wrong for the reason stated for distractor B

Technical References: Operations Instruction #8 [Guidelines for Successful Transient Mitigation](Rev 19), Lesson Plan COR002-15-02 [Nuclear Boiler Instrumentation](Rev 28)

References to be provided to applicants during exam: none

Learning Objective: COR002-15-02 Obj. 04h, Describe the following concepts as they apply to NBI: Recirculation flow effects on level indicators

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	

10CFR Part 55 Content:	55.41(b)(5)
Level of Difficulty:	3

SRO Only Justification:	N/A
PSA Applicability:	
Top 10 Risk Significant System - NBI	

Operations Instruction #8 GUIDELINE FOR SUCCESSFUL TRANSIENT MITIGATION	Class: Information Use Effective: 03/08/19

- Reduce injection flow to that necessary to maintain pressure in the new band and if necessary slowly raise water level back into preferred reactor level band.

4. Emergency Depressurization (ED)/Anticipated ED Level Response and Control

   a. Related Fundamentals

   - During ED, high steam flow causes downcomer level to rise (WR) and inside shroud level (FZ) to lower due to reactor core differential pressure (manometer effect). The differential level is ~ 100" to 120".
   - When using LPCI for injection, the forced circulation causes fuel zone indication to read higher than actual. Fuel Zone indication accuracy improves as injection rates are lowered. The forced circulation overcomes reactor core differential pressure, thus reducing differential level between WR and FZ indications.
   - When using Core Spray or condensate for injection, fuel zone indication is not affected by injection rate; however, without forced circulation, differential level between WR and FZ is not reduced.
   - When performing an ED for low reactor level, large reactor level oscillations are observed until reactor level is 50" to 100" above TAF due to instabilities in establishing natural circulation. The reactor level oscillations coincide with core flow indications.
   - When performing an ED, large differentials can be expected between the different RPV level instruments until RPV pressure lowers to approximately 30 psig above drywell pressure due to the ongoing manometer effect and various closing setpoints of SRVs. Additional delays may be encountered on the NR and WR indicators coming on scale until their variable legs are refilled.

   b. Strategies

   As plant conditions degrade towards the probability of requiring an ED, it is likely that there is no plant or Control Room activity that will be more important than preparing for ED. It is imperative that the crew communicates and preplans this evolution as early as possible in order to minimize the adverse conditions being experienced in the RPV, primary or secondary containment, or to the public via a radiological release.

NOTE - The following discussion on ED level bands does not apply during ATWS conditions.

- The CRS should ensure sufficient capacity injection sources are pre-staged (i.e. start pump(s)) prior to initiating an ED.)

- For EDs other than for level below TAF a suggested target level band is -110" to 0". There may be cases where RPV level is in a normal +3" to 54" band prior to the ED, and achieving a -110 to 0" band is not easily obtained. In all cases, the goal is to maintain RPV level below +110" Steam Nozzle level. This transient level band will minimize moisture carryover down the Main Steam Lines while maintaining core submergence based on FZ indication. When ED is complete, restore and maintain level to the preferred EOP RPV level band.

- For EDs due to level below TAF the suggested level band is -158" to 0". This level band will obtain core submergence and is wide enough to accommodate the initial oscillations in reactor level caused by natural circulation flow instabilities. The goal is to achieve stable core submergence, and then slowly raise level to the normal bands. When ED is complete, restore and maintain level to the preferred EOP RPV level band.

- It is preferable to install PTM's 97-100 to provide control or prevention of LPCI flow. If PTMs 97-100 are not installed, consider using Core Spray to recover RPV water level. This allows for better level control by throttling CS-MO-12A/B.

- Due to large differences between FZ and WR levels, it is not recommended to use the Condensate System with Startup Level Valves in AUTO. MANUAL control is more effective.

- When using LPCI, making sudden changes in injection flow rate such as securing an RHR pump will cause large change in FZ indication due to effects on core flow. Therefore, evaluate changes

Operations Instruction #8 GUIDELINE FOR SUCCESSFUL TRANSIENT MITIGATION	Class: Information Use Effective: 03/08/19

in LPCI injection with the combined effect on inventory control and fuel zone indication.

- When performing a non-ATWS ED for conditions other than low reactor level and reactor pressure lowers to allow injection from low pressure systems, allow injection flow rate to reach a minimum of 3000 - 4000 gpm (1.5 - 2 Mlb/hr) to prevent reactor level from lowering below TAF.A transitory post -ED recovery band of -40" to +10" CFZ should initially be ordered to ensure the stabilized levels will not exceed 54" on the NR or WR instruments.
  - o After level stabilization, RPV level should then be restored +3" to 54" using NR indicators to allow for resetting of the reactor scram and group 2 isolation.
- If the ED is performed during an ATWS, then the post-ED level bands should be based on the ATWS Conditions direction provided previously.

5. ATWS Level/Power Control

a. Related Fundamentals

- SLC injection is not very effective in reducing reactor power once reactor level has been reduced below approximately -60" FZ due to inadequate mixing of the SLC solution.
- Reactor level will stabilize at a value where reactor power and injection flow rate are balanced. As injection flow rate is reduced and reactor level lowers, reactor power will lower to a value equal to the injection flow rate. Inserting control rods with a constant injection flow rate causes reactor level rise to a new equilibrium value. No significant power reduction will occur until injection flow rate is reduced.

b. Strategies

- Prioritize the Power Leg to establish SLC injection as soon as possible.
- Stop and Prevent is the key strategy to preserving containment. If time and resources permit, installing jumpers to prevent MSIV

Lesson Number:	COR002-15-02	Revision: 28

Fig 15

2) At 100% steam flow, the pressure drop is 7 in. of water.

3) Therefore, at 100% steam flow, the pressure outside the dryer skirt (P_1) is 7 in. of water less than the pressure inside the dryer skirt (P_2).

4) The level outside the dryer skirt (downcomer region) is 7 in. higher than inside the skirt.

5) Since the vessel level instruments compare the reference column height to the downcomer (variable column) height, the setpoints are adjusted to compensate for this 7 in. maximum error.

6) The water level inside the dryer skirt is slightly dome shaped.

7) The moisture separator drains must flow to the outside (downcomer) region. In order for drains from the interior separators to flow outward, a hydraulic gradient is required.

8) At 100% power, the "top" of the dome is 4 in. higher than the "outside", thus providing the hydraulic gradient.

NOTE: The degree of hydraulic gradient is variable, ranging from 0 in. below 10% power to 4 in. at 100% power.

Fig 9

b. Jet Pump/Recirculation Flow Effects

LO-04h, SO-06g

1) Fuel zone instruments tap off jet pump #6 and 16 lower taps. They are only useful with no jet pump flow.

2) The pressure resulting from the jet pump flow causes the differential pressure transmitter to indicate a high indicated fuel zone level.

Lesson Number:	COR002-15-02	Revision: 28

3) The reactor jet pump flow in the annulus region outside the core shroud and past the lower tap of the Wide Range instruments has a significant velocity head and some friction loss which reduces the pressure on the variable leg to the differential pressure (level) instrument, resulting in an indicated level lower than actual.

4) The effect of recirculation flow on RPV level measurement is limited to the Wide Range configuration in which the level instrument nozzle is near the top of the fuel.

5) Accordingly, no effect on RPV level measurement for Narrow Range level measurement exists, or for any measurement in the plant where the level instrument nozzle is well above the shroud head.

6) The inaccuracy introduced by this flow varies approximately as the square of the reactor recirculation flow (velocity head).

7) The friction component, which is small, varies approximately linearly with the flow rate. The combined inaccuracy from these factors depends on recirculation flow rate, area of the annulus, and location of the lower instrument tap.

8) The range of level discrepancy could be from 4 to 18 inches.

c. Subcooling

LO-04I

1) Cold feedwater causes a density rise in the downcomer region below the elevation of the feedwater spargers.

2) The higher density causes the Fuel Zone instrument to read higher than the actual level by a maximum of 1 in.

Examination Outline Cross-Reference	Level	RO
295022 (APE 22) Loss of Control Rod Drive Pumps / 1 Knowledge of the operational implications of the following concepts as they apply to LOSS OF CRD PUMPS: AK1.02 Reactivity control	Tier#	1
	Group#	2
	K/A #	295022 AK1.02
	Rating	3.6
	Revision	0
Revision Statement:		

Question 62

The first RFP is being placed into service during startup from a refueling outage.

The following annunciator is received for the In-service CRD Pump:

CRD PUMP A BREAKER TRIP	PANEL/WINDOW: 9-5-2/A-6

The operator attempts to start CRD Pumps B and A, but NEITHER will start.

What action is required NEXT by Alarm Card 9-5-2/A-6?

A. Immediately insert a scram.

B. Perform a rapid power reduction **and** insert a scram within 20 minutes.

C. When one CRD HCU Accumulator is declared inoperable, immediately insert a scram.

D. After a second CRD HCU Accumulator is declared inoperable, insert a scram within 20 minutes.

Answer: A

Explanation:
This question tests the operational implications of the challenge to reactivity control resulting from loss of both CRD pumps. The first RFP is placed into service between 350-500 psig reactor pressure. Alarm card 9-5-2/A-6 step 1.2 for both CRD pumps off is required when reactor pressure is <900 psig after attempting to start the standby CRD pump. Step 1.2.1.1 directs attempting to restart CRD Pump A. If CRD Pump A

does not restart, step 1.2.1.2 is required, which states IF neither CRD pump can be immediately restarted, THEN SCRAM and enter Procedure 2.1.5. This requirement is irrespective of CRD HCU Accumulator status due to the imminent challenge to reactivity control and in anticipation of HCU Accumulator low pressures, which would impede or prevent a scram if one was required.

Distracters:

Answer B is plausible for the following reasons. “Perform a rapid power reduction” is plausible because procedure 2.1.5 is referenced in the associated alarm card actions, and procedure 2.1.5 directs lowering power before scramming to reduce the severity of the scram transient. Also, HCU accumulator pressures will lower due to loss of CRD charging water pressure with no CRD pump running. “Inserting a scram within 20 minutes” is plausible because it reflects action required per alarm card 9-5-2/G-6 [CRD Accum Low Press or High Level] which require application of TS 3.1.5. TS 3.1.5 Conditions C and D are reflected in this answer. The examinee who confuses the requirements of alarm cards 9-5-2/A-6 and 9-5-2/G-6 and applies TS 3.1.5 for reactor pressure ≥900 psig may choose this answer. It is wrong because alarm card 9-5-2/A-6 requires an immediate scram if neither CRD pump can be restarted, irrespective of CRD HCU Accumulator status. This distractor is RO level because it involves only ≤1 hour action statements.

Answer C is plausible because It reflects action required per alarm card 9-5-2/G-6 [CRD Accum Low Press or High Level] which require application of TS 3.1.5. TS 3.1.5 Condition C is reflected in this answer, which requires immediately inserting a scram when a HCU Accumulator for a withdrawn control rod is declared inoperable. The examinee who confuses the requirements of alarm cards 9-5-2/A-6 and 9-5-2/G-6 and applies TS 3.1.5 for reactor pressure ≥900 psig may choose this answer. It is wrong because alarm card 9-5-2/A-6 requires an immediate scram if neither CRD pump can be restarted, irrespective of CRD HCU Accumulator status. This distractor is RO level because it involves only ≤1 hour action statements.

Answer D is plausible for the same reason given for distractor C. It reflects action required per alarm card 9-5-2/G-6 [CRD Accum Low Press or High Level] which require application of TS 3.1.5. TS 3.1.5 Condition B is reflected in this answer, which requires inserting a scram after a second HCU Accumulator associated with a withdrawn control rod is declared inoperable. The examinee who confuses the requirements of alarm cards 9-5-2/A-6 and 9-5-2/G-6 and applies TS 3.1.5 for reactor pressure ≥900 psig may choose this answer. It is wrong because alarm card 9-5-2/A-6 requires an immediate scram if neither CRD pump can be restarted, irrespective of CRD HCU Accumulator status. This distractor is RO level because it involves only ≤1 hour action statements.

Technical References: TS 3.1.5 [Control Rod Scram Accumulators], Alarm Card 9-5-2/A-6 [CRD Pump A Breaker Trip](Rev 49), Alarm Card 9-5-2/G-6 [CRD Accum Low Press or High Level](Rev 49), Procedure 2.1.1 [Startup Procedure](Rev 197)

References to be provided to applicants during exam: none		
Learning Objective: COR002-04-02 Obj LO 11i, Predict the consequences a malfunction of the following would have on the CRDH system: CRDH pump trip INT007-05-02 EO-6b, From memory, for MODES 1 and 2, state the actions required in ≤ one hour for: one or more control rod scram accumulators inoperable with reactor steam dome pressure < 900 psig. (LCO 3.1.5 C.1, C.2)		
Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(10)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA Applicability:		
N/A		

Initials/Time/Date: ______/______/______

NOTE – RFP must be on line prior to reaching 500 psig.

5.29 IF a RFP not in service,
THEN **START** placing first RFP in service per Procedure 2.2.28.1 when RPV pressure ~ 350 psig.

Initials/Time/Date: ______/______/______

CRD PUMP A BREAKER TRIP

PANEL/WINDOW:
9-5-2/A-6

1. OPERATOR OBSERVATION AND ACTION

1.1 Restore CRD as follows:

1.1.1 Place CRD-FC-301 in MAN.

1.1.2 Adjust CRD-FC-301 to minimum.

1.1.3 WHEN in service FLOW CONTROL VLV AO 19A or 19B indicates closed, THEN start CRD Pump B.

1.1.3.1 IF pump fails to start, THEN go to Step 1.2.

1.1.4 Adjust CRD-FC-301 to obtain flow of 50 gpm.

1.1.5 Balance CRD-FC-301.

1.1.6 Place CRD-FC-301 to BAL.

1.2 IF both CRD pumps off:

1.2.1 **IF Reactor Pressure is < 900 psi with more than one control rod withdrawn, THEN perform following:**

1.2.1.1 **Attempt immediate start of CRD Pump A.**

a. **IF CRD Pump A starts, THEN go to Step 1.1.4.**

1.2.1.2 **IF neither CRD pump can be immediately restarted, THEN SCRAM and enter Procedure 2.1.5.**

1.2.2 Enter Procedure 2.4CRD.

1.2.3 Monitor Control Rod Accumulator pressures and enter applicable LCO 3.1.5, Conditions and Required Actions.

1.2.4 Use CRD-PI-234 (R-903'-SE) for charging water pressure, as CRD-29 isolates CRD-PI-302.

1.2.5 Close CRD-29, CHARGING WATER HEADER ROOT VALVE (R-903'-SE).

1.2.6 Remove Cold Reference Leg Continuous Backfill from service per Procedure 4.6.1.

1.2.7 Notify NBI System Engineer that Cold Reference Leg Continuous Backfill has been removed from service.

Scram Actions

Scram Actions

(continuation)

CRD ACCUM LOW PRESS OR HIGH LEVEL	PANEL/WINDOW: 9-5-2/G-6

1. OPERATOR OBSERVATION AND ACTION

NOTE – Steps 1.1 and 1.2 can be performed concurrently.

1.1 On Panel 9-5, verify following parameters:

- CRD-PI-302, CHG WTR PRESS, at 1425 psig to 1475 psig.
- CRD-DPI-303, DR WTR DP, at 260 to 270 psid.
- CRD-FI-306, CL WTR FLOW, at 45 to 55 gpm.

1.1.1 Correct any out of normal parameter per Procedure 2.2.8.

1.2 Determine HCU accumulator alarm corrective action per Procedure 2.2.8.

1.2.1 Enter applicable LCO 3.1.5, Conditions and Required Actions.

1.3 IF all of following:

- **Reactor pressure < 900 psi.**
- **One control rod accumulator inoperable with associated control rod not fully inserted.**
- **CRD-PI-302, CHG WTR PRESS, < 940 psig.**

THEN perform following:

1.3.1 Immediately insert affected control rod.

1.3.2 Monitor for other HCU accumulator low pressure alarms.

1.3.3 IF a second control rod accumulator becomes inoperable with associated control rod not fully inserted, THEN SCRAM and enter Procedure 2.1.5.

Scram Actions

Scram Actions

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One or more control rod scram accumulators inoperable with reactor steam dome pressure < 900 psig.	C.1	Verify the associated control rods are fully inserted.	Immediately upon discovery of charging water header pressure < 940 psig
	AND		
	C.2	Declare the associated control rod inoperable.	1 hour
D. Required Action B.1 or C.1 and associated Completion Time not met.	D.1	-------------NOTE------------ Not applicable if all inoperable control rod scram accumulators are associated with fully inserted control rods. ----------------------------------- Place the reactor mode switch in the shutdown position.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.5.1	Verify each control rod scram accumulator pressure is ≥ 940 psig.	In accordance with the Surveillance Frequency Control Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Two or more control rod scram accumulators inoperable with reactor steam dome pressure ≥ 900 psig.	B.1 Restore charging water header pressure to ≥ 940 psig.	20 minutes from discovery of Condition B concurrent with charging water header pressure < 940 psig
	AND	
	B.2.1 --------NOTE--------- Only applicable if the associated control rod scram time was within the limits of Table 3.1.4-1 during the last scram time Surveillance. ---------------------	
	Declare the associated control rod scram time "slow."	1 hour
	OR	
	B.2.2 Declare the associated control rod inoperable.	1 hour

(continued)

CRD ACCUM LOW PRESS OR HIGH LEVEL

PANEL/WINDOW: 9-5-2/G-6

1. OPERATOR OBSERVATION AND ACTION

NOTE – Steps 1.1 and 1.2 can be performed concurrently.

1.1 On Panel 9-5, verify following parameters:

- CRD-PI-302, CHG WTR PRESS, at 1425 psig to 1475 psig.
- CRD-DPI-303, DR WTR DP, at 260 to 270 psid.
- CRD-FI-306, CL WTR FLOW, at 45 to 55 gpm.

1.1.1 Correct any out of normal parameter per Procedure 2.2.8.

1.2 Determine HCU accumulator alarm corrective action per Procedure 2.2.8.

1.2.1 Enter applicable LCO 3.1.5, Conditions and Required Actions.

1.3 IF all of following:

- **Reactor pressure < 900 psi.**
- **One control rod accumulator inoperable with associated control rod not fully inserted.**
- **CRD-PI-302, CHG WTR PRESS, < 940 psig.**

THEN perform following:

1.3.1 Immediately insert affected control rod.

1.3.2 Monitor for other HCU accumulator low pressure alarms.

1.3.3 IF a second control rod accumulator becomes inoperable with associated control rod not fully inserted, THEN SCRAM and enter Procedure 2.1.5.

Scram Actions

Scram Actions

3. REACTOR SCRAM

NOTE 1 – This procedure may not address all possible plant conditions, and therefore, some steps may not apply. If steps are performed out-of-sequence or not performed, user and either CRS or SM shall ensure all applicable steps are performed and procedure intent is not altered. If steps are not performed, justification for non-performance shall be documented.

NOTE 2 – When reactor is scrammed, any of following may occur due to low water level caused by void collapse (shrink):

- Low reactor water level scram.
- Groups 2, 3, and 6 Isolation.
- HPCI initiation.
- RCIC initiation.
- ARI initiation.
- RR pump trip.

NOTE 3 – Following a reactor scram, control rod positions can be determined by any of following methods:

- By observing "FULL IN" green indicators on Full Core Display.
- By placing REACTOR MODE switch in "REFUEL" position, turning Rod Power Select switch to "OFF" position and then back to "ON" position, and then observing "REFUEL PERMISSIVE" white light illuminated (indicates all control rods fully inserted).
- By observing individual control rod position by selecting each control rod on Rod Select Matrix and observing control rod position on Four Rod Display.
- By observing RPIS Full Core Display on PMIS.

NOTE 4 – Steps 3.1.1, 3.1.2, and 3.1.3 may be performed concurrently.

3.1 IF time permits, THEN perform following:

3.1.1 Lower core flow to $40x10^6$ lbs/hr by performing rapid power reduction per Procedure 2.1.10.

3.1.2 Ensure 4160V Buses 1C and 1D are transferred to Startup Transformer per Procedure 2.2.18.1.

3.1.3 Ensure 4160V Buses 1A and 1B are transferred to Startup Transformer per Procedure 2.2.18.1.

Examination Outline Cross-Reference	Level	RO
271000 (SF9 OG) Offgas Ability to manually operate and/or monitor in the control room: A4.02 System flows	Tier#	2
	Group#	2
	K/A #	271000 A4.02
	Rating	2.9
	Revision	0
Revision Statement:		

Question 63

The plant is at 70% power.

A sustained hydrogen combustion is occurring in the Off-gas system.

According to Procedure 2.4OG [Off-Gas Abnormal]…

(1) Where does the operator monitor Off-gas flow during this transient?

AND

(2) How does the operator temporarily reduce Off-gas flow to zero to extinguish the hydrogen combustion for this condition?

A. (1) VBD-K
(2) Fully isolate AOG

B. (1) VBD-K
(2) Close SJAE suction valves

C. (1) Panel B
(2) Fully isolate AOG

D. (1) Panel B
(2) Close SJAE suction valves

Answer: D

Explanation:
This question requires knowledge of how Offgas flow is monitored in the control room and overall mitigative strategy of the AOP for extinguishing a hydrogen combustion in the Offgas system by interrupting Offgas flow. According to Procedure 2.4OG, Ignitions in the Off-Gas System usually start in the AOG System and propagate upstream until they reach the air ejector after-condenser where the sustained

combustion occurs. A sustained combustion at the air ejector is indicated by air ejector flow dropping to a low value along with a rising air ejector drain temperature and subsequent conductivity rise in the hotwell. In order to extinguish the combustion, it is necessary to interrupt the off-gas flow through the air ejector long enough to put out the hydrogen flame and permit cooling of the hot spots to preclude re-ignition. Offgas flow is interrupted by closing SJAE suction valves, venting the suction lines via test connections for 5 minutes, then reopening SJAE suction valves. SJAE A and B flow indicated on Panel B recorder AR-FR-47 is what is referenced in procedure 2.4OG as "off-gas" flow.

Distracters:
Answer A part 1 is plausible because VBD-K contains Offgas valves and dilution fan controls and indication related to Offgas and because the indicators used to monitor Offgas flow are actually labeled SJAE flow, not Offgas flow. It is wrong because Offgas flow is not indicated on VBD-K. Part 2 is plausible because isolating AOG (Augmented Offgas system) would eventually stall flow through the SJAEs, and procedure 2.4OG directs isolation of AOG for certain conditions (i.e. hydrogen explosion, high radiation). It is wrong because for a hydrogen combustion, 2.4OG directs stopping offgas flow through the SJAEs by temporarily closing their suction valves.

Answer B part 1 is plausible and wrong for the reason given for distractor A. Part 2 is correct.

Answer C part 1 is correct. Part 2 is plausible and wrong for the reason given for distractor A.

Technical References: Procedure 2.4OG [Off-Gas Abnormal](Rev 27)

References to be provided to applicants during exam: none

Learning Objective: INT032-01-32 EO-L, Given plant condition(s) and the applicable Abnormal/Emergency Procedure, discuss the correct subsequent actions required to mitigate the event(s).

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	

10CFR Part 55 Content:	55.41(b)(4),(5)
Level of Difficulty:	3

SRO Only Justification:	N/A
PSA Applicability:	
N/A	

CNS OPERATIONS MANUAL ABNORMAL PROCEDURE 2.4OG OFF-GAS ABNORMAL	USE: CONTINUOUS QUALITY: QAPD RELATED EFFECTIVE: 8/21/19 APPROVAL: ITR-RDM OWNER: AOM-SUPPORT DEPARTMENT: OPS

Scram Actions

1. ENTRY CONDITIONS

 1.1 High/low/erratic off-gas flow.

 1.2 Condenser vacuum degrading.

 1.3 SJAE steam supply pressure lowering.

 1.4 Elevated SJAE radiation monitor indication.

 1.5 High/low OG Dilution D/P.

 1.6 Condenser conductivity rising.

 1.7 CAM alarming in Off-Gas Building.

 1.8 ERP Process flow inaccurate or unknown.

2. AUTOMATIC ACTIONS

 2.1 Standby off-gas dilution fan starts on low dilution flow.

 2.2 A 5 minute time delay on low dilution flow or 15 minutes of continuous Alarm 9-4-1/C-4, OFFGAS TIMER INITIATED, causes an off-gas isolation signal.

 2.3 An off-gas isolation signal causes following:

  2.3.1 OG-AO-254, OG SYSTEM ISOLATION, closes.

  2.3.2 AOG-AO-902, AOG RETURN, closes.

  NOTE – 50 to 60 psig on AR-12AV and OG-13AV air regulators indicates valves closed.

  2.3.3 OG-AO-13, OFF-GAS FILTERS A & B DRAIN, closes.

  2.3.4 AR-AO-12, 30 MINUTE HOLDUP PIPE DRAIN, closes.

  2.3.5 OWC Injection System trips.

Scram Actions

3. IMMEDIATE OPERATOR ACTION

 3.1 None.

ATTACHMENT 5 INFORMATION SHEET

1. DISCUSSION

1.1 Ignitions in the Off-Gas System usually start in the AOG System and propagate upstream until they reach the air ejector after-condenser where the sustained combustion occurs. A sustained combustion at the air ejector is indicated by air ejector flow dropping to a low value along with a rising air ejector drain temperature and subsequent conductivity rise in the hotwell. In order to extinguish the combustion, it is necessary to interrupt the off-gas flow through the air ejector long enough to put out the hydrogen flame and permit cooling of the hot spots to preclude re-ignition.

1.2 If an explosion has occurred in the off-gas piping, it may be necessary to shut the reactor down to safely inspect the Off-Gas System.

1.3 A rise in off-gas activity could indicate fuel failure or a reduced holdup time. Reactor power must be lowered to maintain the off-gas activity within limits.

1.4 Should the off-gas flow drop to zero on AR-FR-47, it would indicate that SJAE is not working properly, suction valves to SJAE have closed, or off-gas isolation valves have closed.

1.5 An abnormal rise in off-gas flow would indicate equipment failure or valving error has occurred. Greater in-leakage reduces holdup time for radioactive decay of activated gases and introduces errors into the off-gas reading.

1.6 The possibilities of losing both dilution fans at the same time are remote. However, if such a condition were to exist, the SGT System may be operated in such a manner to provide dilution flow until repairs or plant shutdown can be accomplished. If the AOG System is not in service, a reactor scram is required to preclude the possibility of reaching a combustible atmosphere in the Off-Gas Building.

1.7 ERP flow indication is shared between the recorder and associated Kaman effluent monitors. The monitors use the ERP flow rate to determine effluent release rates in terms of micro-curies per second. An anomalous exhaust flow indication will directly affect the accuracy of the effluent monitors. ® [1.4]

1.8 PROBABLE CAUSES

1.8.1 Loss of off-gas dilution fans.

1.8.2 Explosion or sustained combustion in Off-Gas System.

1.8.3 Fuel element failure.

1.8.4 Loss of power.

ATTACHMENT 2 OFF-GAS EXPLOSION/COMBUSTION

1.2.2 IF temperatures indicated on both points are trending above 200°F, THEN go directly to Step 1.3.

NOTE – Annotate which valve(s) in Step 1.2.3 was closed.

1.2.3 Close following air ejector suction valve(s) on in service air ejector with higher drain temperature (PANEL B):

1.2.3.1 AR-AO-165, SJAE A SUCT (BLUE) FM CNDR A VLV.

1.2.3.2 AR-AO-151, SJAE A SUCT (RED) FM CNDR B VLV.

1.2.3.3 AR-AO-152, SJAE B SUCT (RED) FM CNDR A VLV.

1.2.3.4 AR-AO-166, SJAE B SUCT (BLUE) FM CNDR B VLV.

NOTE – Two 8" adjustable wrenches will be required to remove cap from CD-545 or CD-526.

1.2.4 Remove cap and open following air ejector suction sample test point on air ejector with higher drain temperature:

1.2.4.1 SJAE A: CD-545, SJAE FIRST STAGE 1A1 TEST CONNECTION (Turbine Generator Building Corridor 882′ above and behind LRP-RACK-IR-IE).

1.2.4.2 SJAE B: CD-526, SJAE FIRST STAGE 1B1 TEST CONNECTION (Turbine Generator Building Corridor 882′ above and behind LRP-RACK-IR-IE).

1.2.5 Monitor condenser vacuum closely.

1.2.6 AFTER ~ 5 minutes, THEN close valve opened in Step 1.2.4 and replace cap.

1.2.6.1 CD-545.

1.2.6.2 CD-526.

1.2.7 Open in service air ejector suction valve closed in Step 1.2.3.

1.2.8 IF combustion continues in same SJAE, THEN return to Step 1.2.1.

1.2.9 IF combustion stopped, THEN drain temperature will stabilize at a lower value.

1.2.9.1 Ensure condenser vacuum returns to normal value.

1.2.9.2 Exit this attachment.

ATTACHMENT 2 OFF-GAS EXPLOSION/COMBUSTION

1.3 IF combustion cannot be extinguished due to hydrogen flame jumping from one air ejector to the other, THEN perform following; N/A if unit has been removed from service per Step 1.1.1:

NOTE – Annotate which valves in Step 1.3.1 were closed.

1.3.1 Ensure all in service air ejector suction valves closed (PANEL B):

1.3.1.1 AR-AO-165, SJAE A SUCT (BLUE) FM CNDR A VLV.

1.3.1.2 AR-AO-151, SJAE A SUCT (RED) FM CNDR B VLV.

1.3.1.3 AR-AO-152, SJAE B SUCT (RED) FM CNDR A VLV.

1.3.1.4 AR-AO-166, SJAE B SUCT (BLUE) FM CNDR B VLV.

NOTE – Two 8" adjustable wrenches will be required to remove cap from CD-545 and CD-526.

1.3.2 Remove caps and open both air ejector suction sample test valves.

1.3.2.1 SJAE A: CD-545, SJAE FIRST STAGE 1A1 TEST CONNECTION (Turbine Generator Building Corridor 882' above and behind LRP-RACK-IR-IE).

1.3.2.2 SJAE B: CD-526, SJAE FIRST STAGE 1B1 TEST CONNECTION (Turbine Generator Building Corridor 882' above and behind LRP-RACK-IR-IE).

1.3.3 Monitor condenser vacuum closely.

1.3.4 AFTER ~ 5 minutes, THEN close following valves and replace caps:

1.3.4.1 CD-545.

1.3.4.2 CD-526.

1.3.5 Open air ejector suction valves closed in Step 1.3.1.

1.3.6 IF combustion stopped, THEN drain temperature will stabilize at a lower value.

1.3.7 Repeat Step 1.3, as required, to stop combustion.

1.3.8 Ensure condenser vacuum returns to normal value.

1.3.9 Exit this attachment.

ATTACHMENT 2 OFF-GAS EXPLOSION/COMBUSTION

1. OFF-GAS EXPLOSION/COMBUSTION

1.1 IF explosion in system suspected, THEN perform following:

1.1.1 IF damage to Off-Gas System causing unsafe conditions, THEN perform following:

1.1.1.1 Enter Procedure 2.1.5.

1.1.1.2 Close following SJAE suction valves (PANEL B):

a. AR-AO-151, SJAE A SUCT (RED) FM CNDR B VLV.

b. AR-AO-152, SJAE B SUCT (RED) FM CNDR A VLV.

c. AR-AO-165, SJAE A SUCT (BLUE) FM CNDR A VLV.

d. AR-AO-166, SJAE B SUCT (BLUE) FM CNDR B VLV.

1.1.1.3 At Panel 9-02, place OFFGAS TIMER control switch in CLOSE.

1.1.1.4 WHEN reactor power < 5%, THEN start a mechanical vacuum pump per Procedure 2.2.55.

1.1.2 IF AOG isolation desired, THEN perform following:

1.1.2.1 Open OG-AO-254, OFF GAS SYSTEM ISOLATION; N/A if OFFGAS TIMER control switch in CLOSE (VBD-K).

1.1.2.2 Close AOG-AO-901, AOG SUPPLY (VBD-K).

1.1.3 Ensure off-gas dilution fan operating (VBD-K).

WARNING – Off-Gas Building may be a high radiation area, have high airborne activity, or high hydrogen concentration; ensure proper radiological support coverage.

1.1.4 Fill loop seals in Off-Gas Building per Attachment 4.

NOTE – SJAE drain temperatures > 200°F indicates burn (combustion) in-progress.

1.2 IF off-gas combustion suspected, THEN perform following; N/A if reactor has been scrammed per Step 1.1.1:

1.2.1 Monitor PMIS Points F040, STM JET AIR EJECT 1A DRAIN, and F041, STM JET AIR EJECT 1B DRAIN (PMIS Group BURN), throughout remaining actions.

ATTACHMENT 1 OFF-GAS SYSTEM HIGH RADIATION

1. OFF-GAS SYSTEM HIGH RADIATION

1.1 Lower reactor power per Procedure 2.1.10 to prevent off-gas timer from timing out or to clear Annunciator 9-4-1/C-4, OFFGAS TIMER INITIATED.

1.2 IF off-gas isolation immediately desired, THEN at Panel 9-02, place OFFGAS TIMER switch to CLOSE.

1.3 IF fuel cladding has not been confirmed lost per EPIP 5.7.1, THEN request Chemistry obtain isotopic analysis of off-gas stream.

1.4 **IF Off-Gas System automatically isolates or manually isolated due to high-high radiation, THEN perform following:**

Scram Actions

1.4.1 **SCRAM and enter Procedure 2.1.5.**

1.4.2 Close MSIVs and MSIV drains.

1.4.3 Ensure OFFGAS TIMER switch on Panel 9-02 in CLOSE.

1.4.4 Ensure following valves closed:

1.4.4.1 RHR-920MV, AOG STEAM SUPPLY VALVE (PNL 9-3).

1.4.4.2 RHR-1485MV, AOG STEAM BYP THROTTLE VLV (PNL 9-3).

1.4.4.3 RHR-921MV, AOG STEAM SUPPLY VALVE (PNL 9-3).

1.4.4.4 AOG-AO-902, AOG RETURN (VBD-K).

1.4.4.5 OG-AO-254, OFFGAS SYSTEM ISOLATION (VBD-K).

1.4.5 Remove SJAEs from service per Procedure 2.2.55.

1.4.6 Ensure gland steam exhauster running.

NOTE – N/A Steps 1.4.7 and 1.4.8 if Auxiliary Boiler not in service.

1.4.7 Ensure MS-MO-53, AUX STM TO TURB GLAND SEAL, open (PANEL B).

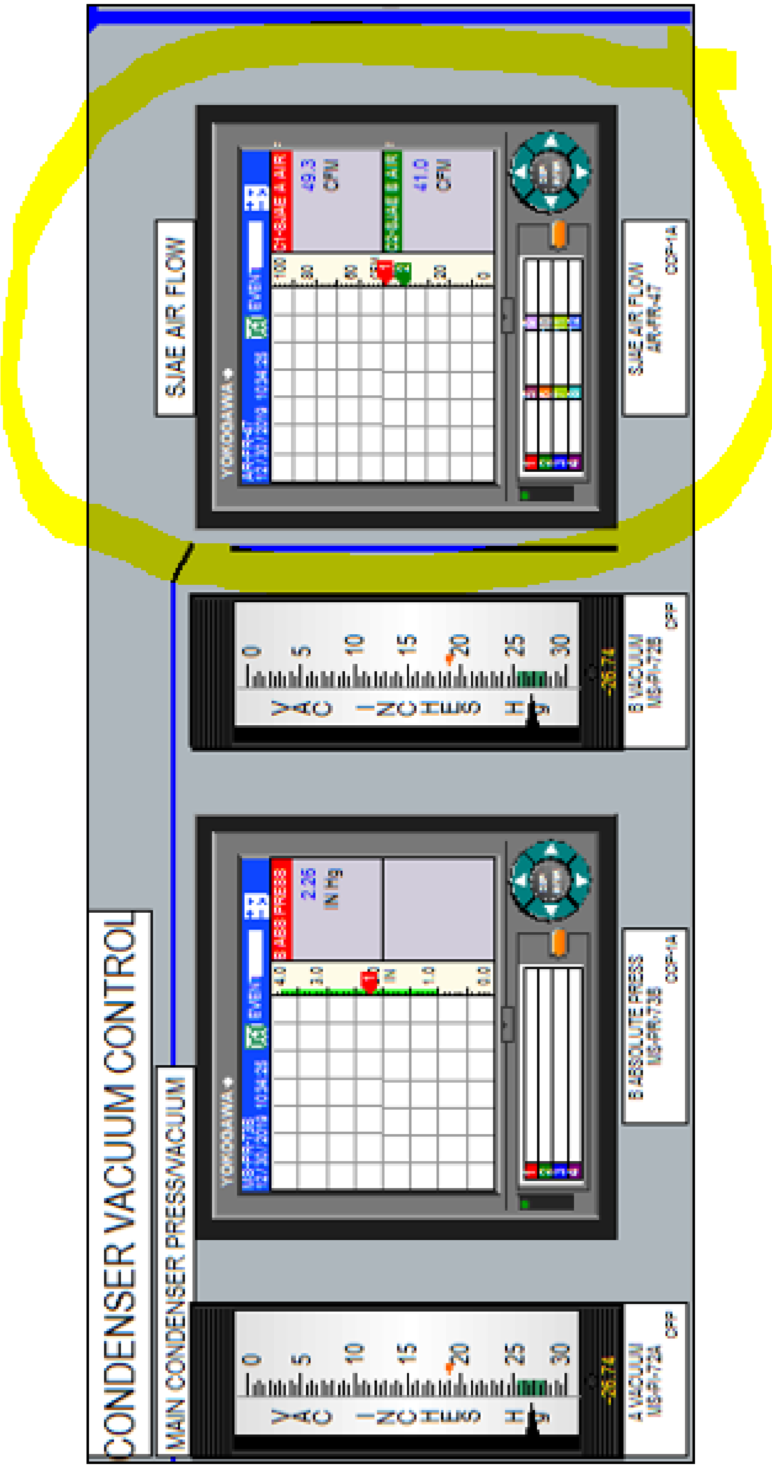
1.4.8 Ensure AS-MO-2241, AUX STM TO TURB GLAND SEAL, open supplying auxiliary sealing steam (PANEL B).

1.4.9 Do not open AR-MO-150, VACUUM BREAKER.

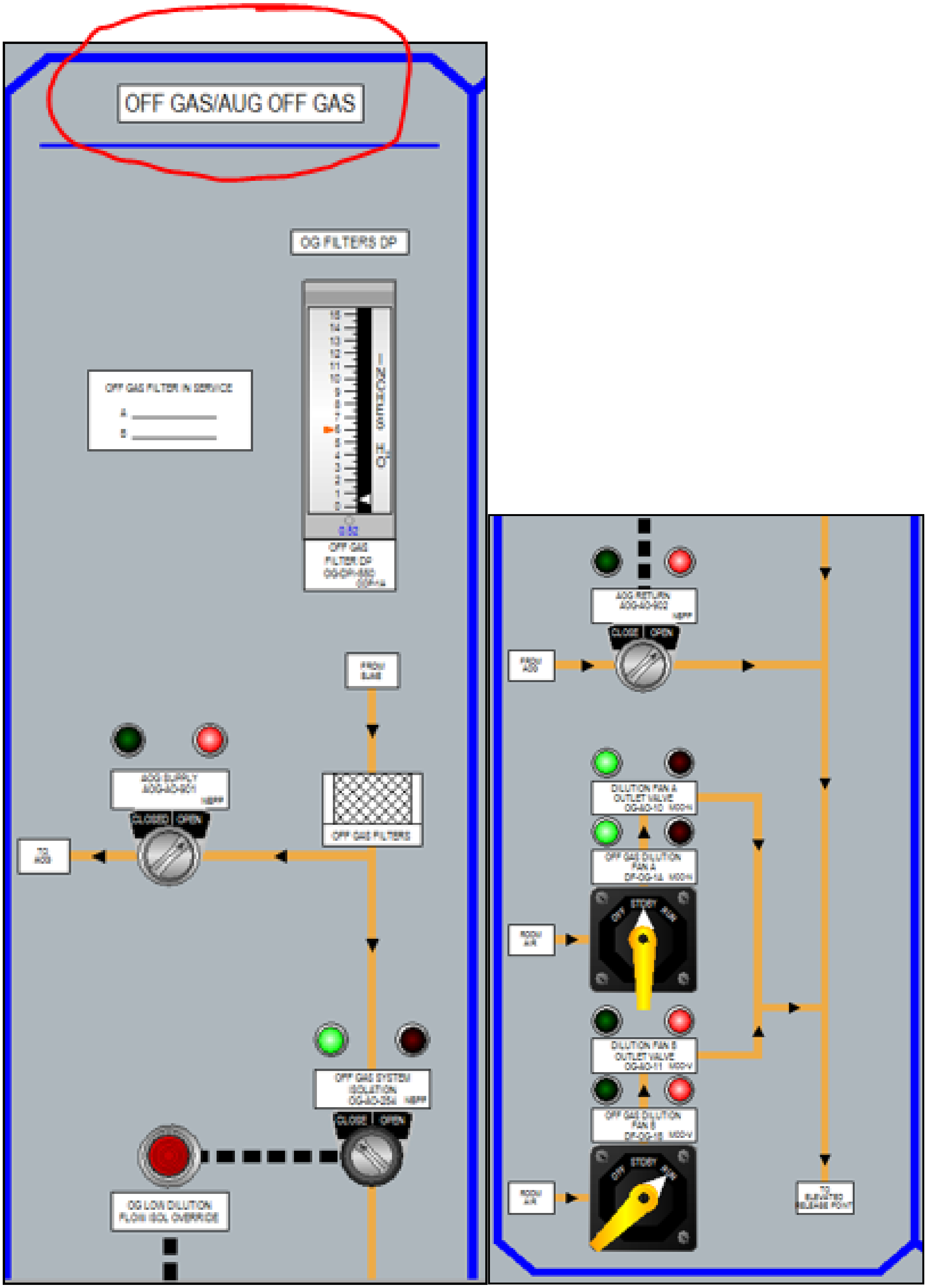
1.4.10 Monitor ERP gas activity levels.

Scram Actions

From Panel B:


SJAE AIR FLOW
SJAE AIR FLOW
AR-FR-47
49.3
CFM
41.0
CFM
B VACUUM
MS-PI-72B
-26.74
VAC INCHES Hg
B ABSOLUTE PRESS
MS-PR-73B
2.26
IN Hg
A VACUUM
MS-PI-72A
CONDENSER VACUUM CONTROL
MAIN CONDENSER PRESS/VACUUM

From VBD-K:


OFF GAS/AUG OFF GAS
OG FILTERS DP
OFF GAS FILTER IN SERVICE
OFF GAS FILTERS
OFF GAS SYSTEM ISOLATION
CLOSE
OPEN
OG LOW DILUTION FLOW ISOL OVERRIDE
DILUTION FAN A OUTLET VALVE
OFF GAS DILUTION FAN A
DILUTION FAN B OUTLET VALVE
OFF GAS DILUTION FAN B
OFF
STDBY
RUN

Examination Outline Cross-Reference	Level	RO
600000 (APE 24) Plant Fire On Site / 8 Ability to operate and / or monitor the following as they apply to PLANT FIRE ON SITE: AA1.08 Fire fighting equipment used on each class of fire	Tier#	1
	Group#	1
	K/A #	600000 AA1.08
	Rating	2.6
	Revision	0
Revision Statement:		

Question 64

The control room annunciator related to DG1 room fire suppression has just been received due to a fire in an electrical cabinet inside DG1 room.

No personnel are in the area.

(1) When does DG1 room fire extinguishing agent dispense relative to the time the associated fire detection instrumentation trips?

AND

(2) For the fire brigade making entry into DG1 room, what is the primary hazard related to the extinguishing agent dispensed with this class of fire?

A. (1) Immediately
(2) Suffocation

B. (1) Immediately
(2) Electrocution

C. (1) After a 50 second delay
(2) Suffocation

D. (1) After a 50 second delay
(2) Electrocution

Answer: C

Explanation:

Each Diesel Generator room has its own total flooding, high pressure CO2 system, which consists of 38, high pressure (750 psig), cylinders interconnected to a discharge manifold, and a discharge piping system which floods the entire volume of the Diesel Generator room and its associated fuel oil day tank room. The system is automatically actuated by any two smoke detectors in the DG room, and/or by a thermal detector, set at 190ºF, in the associated diesel fuel oil day tank room.

Automatic actuation from detection sensors is delayed for 50 seconds to allow for system abort or personnel evacuation. Manual actuation, regardless of where initiated, will immediately actuate CO2 into the selected DG and Day Tank rooms.

CO2 is a Class 3 fire extinguishing agent suitable for use on fires where live electrical equipment is located and is designed to suppress electrical equipment fires and, to an extent, flammable liquids. CO2 is non-conductive and suppresses a fire by oxygen displacement. The DG1 room CO2 system is designed to yield a 35% concentration with a 20 minute hold time. CO2 discharge results in an atmosphere that is immediately dangerous to life and health (IDLH) due to oxygen displacement which requires use of a Self-Contained Breathing Apparatus (SCBA) to prevent suffocation of personnel entering the affected area.

Distracters:
Answer A part 1 is plausible because a manual discharge of the DG 1 high pressure CO2 system results in immediate discharge. However, automatic initiation is delayed for 50 seconds to allow personnel egress or system abort. Part 2 is correct.

Answer B part 1 is plausible and wrong for the reasons stated for distractor A. Part 2 is plausible because water sprinkler systems are used in some areas where energized electrical equipment predominates, such as the Electrical Cable Spreading Room. Water is conductive, so in the presence of energized electrical equipment it can present an electrocution hazard to personnel. It is wrong because DG1 room is protected by high pressure CO2, only, which is non-conductive and does not present an electrocution hazard.

Answer D part 1 is correct. Part 2 is plausible and wrong for the reasons stated for distractor B.

Technical References: Lesson plan COR001-05-01 [Fire Protection System](Rev 36), Alarm Card FP-3/E-4 [Diesel Gen 1 CO2 System Activated](Rev 16), procedure 2.2.2 [Carbon Dioxide Systems](Rev 42)

References to be provided to applicants during exam: none

Learning Objective: COR001-05-01 Obj LO-8l, Describe the Fire Protection system design features and/or interlocks that provide for the following: Automatic system initiation

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X

Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(4)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA Applicability:		
N/A		

SETPOINT	CIC	FP-3/E-4
Activation of CO_2 System	CO_2-PS-CO1	

TRM FP DETECTORS

Detector	Location
• CNS-0-CO2-SD-DG1A	DG1 Room
• CNS-0-CO2-SD-DG1B	DG1 Room
• CNS-0-CO2-SD-DG1C	DG1 Room
• CNS-0-CO2-SD-DG1D	DG1 Room

NON-TRM FPP REQUIRED FP DETECTORS

- None.

NON-FPP DETECTORS

- CNS-0-CO2-TD-DG1 Location: DG1 Day Tank Room.

REFERENCES

- Administrative Procedure 0.23, CNS Fire Protection Plan.
- Administrative Procedure 0-BARRIER-MAPS, Barrier Maps.
- System Operating Procedure 2.2.2, Carbon Dioxide Systems.
- Emergency Procedure 5.1INCIDENT, Site Emergency Incident.

DIESEL GEN 1 CO2 SYSTEM ACTIVATED	PANEL/WINDOW: FP-3/E-4

1. AUTOMATIC ACTIONS

1.1 HV-FCU-(HV-DG-1A) trips.

NOTE – HV-FCU-(HV-DG-1C) will not trip if a DG1 emergency start signal is present or if IS/DG-1A is in ISOL.

1.2 HV-FCU-(HV-DG-1C) trips.

1.3 Selected high pressure CO_2 storage bottles dump into Diesel Room 1A.

2. OPERATOR OBSERVATION AND ACTION

2.1 Enter Procedure 5.1INCIDENT.

2.2 Secure both fuel oil transfer pumps until fire extinguished:

2.2.1 Open Breaker 2A on MCC-K, PUMP 1A (R-903-NE).

2.2.2 Open Breaker 3B on MCC-S, PUMP 1B (R-903-SW).

2.2.3 Close DGDO-10, PUMP A DISCHARGE VALVE (YD-903-S).

2.2.4 Close DGDO-13, PUMP B DISCHARGE VALVE (YD-903-S).

2.3 WHEN directed by Control Room, THEN reset DG-1 CO_2 System per Procedure 2.2.2 to ventilate DG-1 Room.

Fig 10
SO-04c
LO-01i
LO-07a, 09d,
SO-22a,24d

3. Total Flooding High Pressure CO_2 system

a. Basic Operation

Each Diesel Generator room has its own total flooding, high pressure CO_2 system, which consists of 38, high pressure (750 psig), cylinders interconnected to a discharge manifold, and a discharge piping system which floods the entire volume of the Diesel Generator room and its associated fuel oil day tank room. The system is automatically actuated by any two smoke detectors in the DG room, and/or by a thermal detector, set at 190°F, in the associated diesel fuel oil day tank room.

LO-08j, m

Automatic actuation from detection sensors is delayed for 50 seconds to allow for system abort or personnel evacuation. Manual actuation, regardless of where initiated, will immediately actuate CO_2 into the selected DG and Day Tank rooms. Only authorized personnel should abort the system.

Automatic or manual discharge of the system causes local strobe lights and alarm horns to actuate a Control Room Annunciator. The system has a design concentration of 35% CO_2 with a 20 minute hold time.

Lesson Number: COR001-05-01	Revision: 36

These systems also consist of piping with closed head type sprinklers; however, instead of an alarm check valve, they use the same type of standard deluge valve as the deluge sprinkler systems.

The pre-action sprinkler systems have a supervisory air system. The air system maintains the sprinkler system's release enclosing box and the riser (a dry pipe) between the isolating deluge valve and the piping containing the closed sprinkler head at approximately 20 to 42 oz. If this air pressure drops as sensed at the release enclosing box, a trouble alarm is received (~24 oz), indicating a breach of system integrity; this initiates an alarm of the system, the alarm does NOT actuate the deluge valve.

LO-07a, b; 08l
SO-22a, 22b

The Deluge valve may be actuated by:

1. Local pull handle
2. Break glass
3. Push button in the Control Room
4. Heat activated device
5. Loss of 24 ounce supervisory air from release enclosing box (at 16 oz.)

LO-09d, SO-24d

Once the deluge valve does trip, the pipe is pressurized to fire main pressure. When the sprinkler heads activate, any air trapped in the piping is vented off, and water is discharged onto the affected area. The time lag, between deluge valve opening and the sprinkler head activating, may allow plant personnel to determine alarm accuracy, or manually extinguish a small fire before the water is automatically discharged. Also, only the areas actually requiring water spray, would receive it. This minimizes water damage to only the affected area.

SO-04a

The areas protected by Pre-action Type sprinkler systems are:

a. Electrical Cable Spreading Room (System 5)
b. ~~Recirculation System Motor-Generator Sets (System 6)~~
c. Multi-Purpose Facility (MPF) (System 38)

1.2.3 Each diesel generator unit has a separate total flooding high pressure CO_2 System, which consists of thirty-eight, high pressure (750 psig), 75 lb cylinders interconnected to a discharge manifold, and a discharge piping system which floods the entire volume of the single Diesel Generator Room and Diesel Fuel Oil Day Tank Room. The system is automatically actuated by smoke detectors (two out of four) above the diesel engine or by a thermal detector in the Diesel Fuel Oil Day Tank Room. Each separate system acts as a reserve for the other which provides the total flooding capability of seventy-six CO_2 bottles. Automatic or manual discharge of the CO_2 System causes local strobe lights and alarm horns to activate, and an annunciator in the Control Room to alarm.

1.2.4 The high pressure systems may by manually discharged by pneumatic release bottles near the Boiler Room entrance to the DG Building, near the DG-1 Room Security door, and on the west wall inside each Diesel Generator Room. There are three manual pneumatic release bottles associated with a given Diesel Generator Room. Actuation of the pneumatic release bottle nearest the DG-1 Room Security door releases the CO_2 bottles in the DG-1 Room into the DG-1 Room. Actuation of the other pneumatic release bottle near the DG-1 Room Security door releases the DG-2 Room CO_2 bottles into the DG-1 Room. Actuation of the pneumatic release bottle on the west wall inside the DG-1 Room releases the CO_2 bottles in the DG-2 Room into the DG-2 Room. Actuation of the pneumatic release bottle nearest the Boiler Room entrance to the DG Building releases the CO_2 bottles in the DG-2 Room into the DG-2 Room. Actuation of the other pneumatic release bottle near the Boiler Room entrance to the DG Building releases the DG-1 Room CO_2 bottles into the DG-2 Room. Actuation of the pneumatic release bottle on the west wall inside the DG-2 Room releases the CO_2 bottles in the DG-1 Room into the DG-1 Room.

1.2.5 During normal plant operations, upon initiation of the DG CO_2 System, the DG H&V fans will be isolated via Pressure Switches CO_2-PS-CO1(CO2). During an emergency start of the DG, Pressure Switches CO_2-PS-CO1(CO2) will be bypassed and the DG H&V fans will continue to run even upon a CO_2 actuation. Furthermore, the Diesel Isolation Switches IS/DG1A(DG2A) provide a bypass of Pressure Switches CO_2.PS-CO1(CO2). During the event of the isolation switches in the ISOLATE position, the CO_2 pressure switches will be bypassed and the DG H&V fans will continue to run even upon a CO_2 actuation.

ATTACHMENT 2 INFORMATION SHEET

1.3 Principles Of CO_2 Extinguishment - CO_2 extinguishes a fire by displacing the normal atmosphere; thus, reducing the oxygen content below the 15% required for diffusion flame production. CO_2 is a colorless, odorless, inert, and electrically non-conductive agent which is ~ 50% heavier than air. The CO_2 from either low pressure or high pressure systems is stored and transported through the piping system to the nozzles as a liquid. With the release of the pressure at the nozzle, the liquid CO_2 converts to a gas, with some minute solid particles. The characteristic white cloud seen when CO_2 Systems are discharged is caused by the solid particles and by the moisture in the atmosphere which is solidified by the extremely low temperature (~ -110°F) of the CO_2 gas when discharged. The finely divided particles of solid CO_2 that were discharged usually evaporate rapidly. Therefore, the cooling extinguishing effect of CO_2 is relatively minor.

1.4 Personnel protection is extremely important when operating CO_2 Systems. The total flooding system operates by filling the area with a concentration between 30% to 60%, which is sufficient to suppress combustion. Such a concentration of CO_2 will also suppress the oxidation reaction in the human body. This is why total-flooding CO_2 Systems are required to have pre-discharge alarms and discharge delay devices that allow sufficient time for personnel to evacuate the area before gas is discharged.

1.5 The turbine bearing CO_2 Systems do not have automatic local alarms in area of discharge on turbine deck. Control Room will receive a turbine bearing CO_2 spray alarm (FP3/F-3) 30 seconds prior to discharge and system will discharge for 50 seconds.

1.6 Physiological Effects Of CO_2 Exposure - It has been determined by test that atmospheres containing 3% or 4% CO_2 will cause one to breathe rapidly but will otherwise have no important effect for relative short exposures. A concentration of ~ 9% is about all most people can withstand without losing consciousness within a few minutes. At CO_2 concentrations, > 9% personnel would quickly lose consciousness. At concentrations of ~ 20%, death will follow in ~ 20 to 30 minutes unless the victim is removed to a source of fresh air. Recovery with artificial respiration is usually rapid because of the natural tendency of CO_2 to promote breathing.

2. INTERLOCKS AND SETPOINTS

2.1 The CO_2 purging supply to the main generator is automatically secured at a tank level of 47% by a float valve located inside the storage tank.

2.2 Under normal station operations, actuation of DG-1(2) CO_2 System, sensed by CO_2-PS-CO1(2), causes HV-DG-1A(1B) and HV-DG-1C(1D) to trip and prevents them from running until CO_2-PS-CO1(2) is reset.

2.3 Under an emergency start of the DG, emergency start Relay 4EMX3 will bypass CO_2 Pressure Switches CO_2-PS-CO1(2), ensuring HV-DG-1C(1D) continues to run even upon initiation of the DG CO_2 System.

2.2 Care should be taken when discharging CO_2 that adequate ventilation is available. Oxygen analyzers should be used to monitor atmosphere in an area where CO_2 has been discharged to ensure sufficient dilution of CO_2 to permit entry.

2.3 Control bottle on High Pressure CO_2 System is normally pressurized to ≥ 750 psig and should be replaced as soon as possible when pressure is < 750 psig. However, system may be considered OPERABLE if pressure in bottle is ≥ 500 psig. Ⓟ[1]

2.4 Control bottle outlet pressure on High Pressure CO_2 System is normally pressurized between 290 and 350 psig, and should be investigated and rectified when outside this band. However, the system may be considered OPERABLE if pressure is between 275 and 400 psig.

2.5 Notify Radiation Protection prior to bulk unloading of CO_2 or if a CO_2 leak should develop.

2.6 Notify Radiation Protection if CO_2 is used to extinguish a fire or the system has discharged.

2.7 Contact Radwaste Operations Specialist to unload CO_2 truck, as they are DOT qualified. If unavailable, CO_2 truck driver is allowed to unload under supervision of an Operator.

3. REQUIREMENTS

3.1 Following support systems are available:

3.1.1 MCC-B is energized.

3.1.2 125 VDC Panels AA1, AA2, BB1, DG-1, and DG-2 are energized.

3.1.3 Lighting Panels LPDG-1 and LPDG-2 are energized.

3.2 System Component Checklists, Procedures 2.2.2A and 2.2.2B, are complete to support system operation.

4. PLACING LOW PRESSURE CO_2 SYSTEM IN SERVICE

4.1 Check CO_2 storage tank level at ≥ 43% tank level.

4.1.1 IF < 43%, THEN ensure CO_2 delivery is ordered and do not proceed.

4.2 Ensure turbine bearing CO_2 is reset per Section 6.

5. MANUAL INITIATION OF TURBINE BEARING CO_2 SYSTEM

5.1 Ensure all personnel are clear of turbine bearings 1, 2, and 3 area.

NOTE – If 125 VDC power is not available, proceed to Step 5.3.

5.2 Depress MANUAL pushbutton on northwest corner of turbine shield wall or near turbine front standard entrance.

13. MANUAL INITIATION OF DG-2 CO_2 SYSTEM

NOTE 1 – Following an emergency start of DG2 or placement of IS/DG1B in ISOLATE, manual initiation of DG-2 CO_2 System will result in CO_2 being exhausted to atmosphere due to DG HVAC System interlock with CO_2 System being bypassed.

NOTE 2 – Manual initiation results in immediate discharge of CO_2 into affected room.

NOTE 3 – Pneumatic release bottles are located near DG-1 Room entrance outside of room, in Boiler Room near entrance to DG Building, and on west wall of each DG Room near double doors.

13.1 Ensure all personnel are evacuated from affected room.

13.2 Actuate pneumatic release bottles per posted instructions at bottles.

13.3 Ensuring CO_2-PS-CO2, DG 2 H&V TRIP/RESET (outside room near Security door in Boiler Room near entrance to DG Building), has actuated (plunger extended).

14. RESETTING DG-1 CO_2 SYSTEM®[3]

14.1 Dispatch Operator to DG Building Roof to ensure all personnel are clear of area while CO_2 is being exhausted from DG-1 Room.

14.2 Make gaitronics announcement for all personnel to stand clear of DG-1 Room and DG Building Roof while CO_2 is being exhausted from DG-1 Room.

14.3 Dispatch two Operators wearing SCBAs to DG-1 Room.

14.4 Depress plunger on CO_2-PS-CO1, DG 1 H&V TRIP/RESET (outside room near Security door).

14.5 Place CO2-SW-ABORT(DG1)(SS), SYSTEM ABORT SWITCH FOR DG1 CO2 SYSTEM (west wall), to ABORT.

14.6 At LCP-HV-DG-1A (mezzanine level), place SS/1-HV-DG-1C switch to RUN.

14.7 Exit room and inform Radiation Protection personnel room is being ventilated.

14.8 AFTER Radiation Protection has determined sufficient O_2 concentration exists in DG-1 Room, THEN perform following:

14.8.1 Ensure HV-DG-1A is operating properly per Procedure 2.2.39.

14.8.2 Ensure temperature in DG-1 Fuel Oil Day Tank Room at ambient temperature.

Examination Outline Cross-Reference	Level	RO
201001 (SF1 CRDH) CRD Hydraulic Knowledge of CONTROL ROD DRIVE HYDRAULIC SYSTEM design feature(s) and/or interlocks which provide for the following: K4.12 Controlling CRD system flow	Tier#	2
	Group#	2
	K/A #	201001 K4.12
	Rating	2.9
	Revision	0
Revision Statement:		

Question 65

The plant was manually scrammed **one minute ago** from rated power; the scram has **NOT** been reset.

What is the effect of the scram on CRD total system flow AND in-service CRD Flow Control Valve CRD-AO-19A **now** relative to their status before the scram?

A. CRD System Total Flow **lower**
CRD FCV AO-19A position **more closed**

B. CRD System Total Flow **lower**
CRD FCV AO-19A position **more open**

C. CRD System Total Flow **higher**
CRD FCV AO-19A position **more closed**

D. CRD System Total Flow **higher**
CRD FCV AO-19A position **more open**

Answer: C

Explanation:
This is a modified version of 3/2017 ILT NRC Q#54. It was modified by replacing charging water pressure with CRD FCV position in part 2.

A scram causes CRD HCU accumulators to discharge through the scram inlet valves. CRD charging water header pressure rapidly lowers. CRD system flow, labeled Actual on panel 9-5, which senses nearly all system flow except ~20 gpm minimum flow to CST and ~2 gpm to Recirc and RWCU Pump seals, rises above 100 gpm, with one CRD pump operating, as flow directs toward the charging header. High system flow sensed on the CRD supply header upstream of the charging water branch signals the in-service CRD FCV to close to its minimum setting. Flows downstream of the FCV drop to near 0 gpm as downstream pressure falls to near RPV pressure. One minute after a scram, conditions have essentially stabilized, with nearly all CRD system flow directed to the charging header and routing into the RPV bottom head region through seals of all of the CRDMs, since scram inlet valves are open. CRD Flow Control (Actual) remains higher (~100 gpm with one CRD pump running) than the normal 45 gpm since it reflects the high charging water flow. Charging header pressure has stabilized at a lower value since high charging flow exists.

Distracters:
Answer A is plausible because CRD Flow Control (Actual) indication is sensed downstream of some flow branches (e.g. CR minimum flow to CST, Recirc pump seal purge, etc.). The examinee who remembers the FCV closes but believes CRD Flow Control (Actual) indication is sensed downstream of the charging water branch would choose this answer. It is wrong because CRD Flow Control (Actual) is sensed upstream of the charging header and would, therefore, reflect the high charging water flow following a scram.

Answer B first part is plausible and wrong for the same reasons as given for distractor A. The second part is plausible to the examinee who believes the FCV is upstream of the charging water header branch and must open to route more flow to the CRD HCUs. It is wrong because the FCV is downstream of the charging water header and closes to minimum position when high flow is sensed on the CRD supply header upstream of the charging water branch when the CRD HCUs discharge during a scram.

Answer D first part is correct. The second part is plausible and wrong for the same reasons as given for distractor B relative to the FCV.

Technical References: Procedure 2.2.8 [Control Rod Drive Hydraulic System](Rev 106), B&R Drawing 2039 [CRD Hydraulic System], Lesson Plan COR002-04-02 [CRD System](Rev 30)

References to be provided to applicants during exam: none

Learning Objective: COR002-04-02 Obj 04m, 05b, 05c, 05f, 11f, 15b

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	3/2017 ILT NRC Q#54
	New	
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(6)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	

PSA applicability:
N/A

Question 54

The plant was manually scrammed **one minute ago** from rated power; the scram has **NOT** been reset.

What is the effect of the scram on Control Rod Drive Hydraulic system parameters NOW relative to their values before the scram?

A. CRD System Total Flow → **lower**
Charging Water Pressure → **lower**

B. CRD System Total Flow → **lower**
Charging Water Pressure → **higher**

C. CRD System Total Flow → **higher**
Charging Water Pressure → **lower**

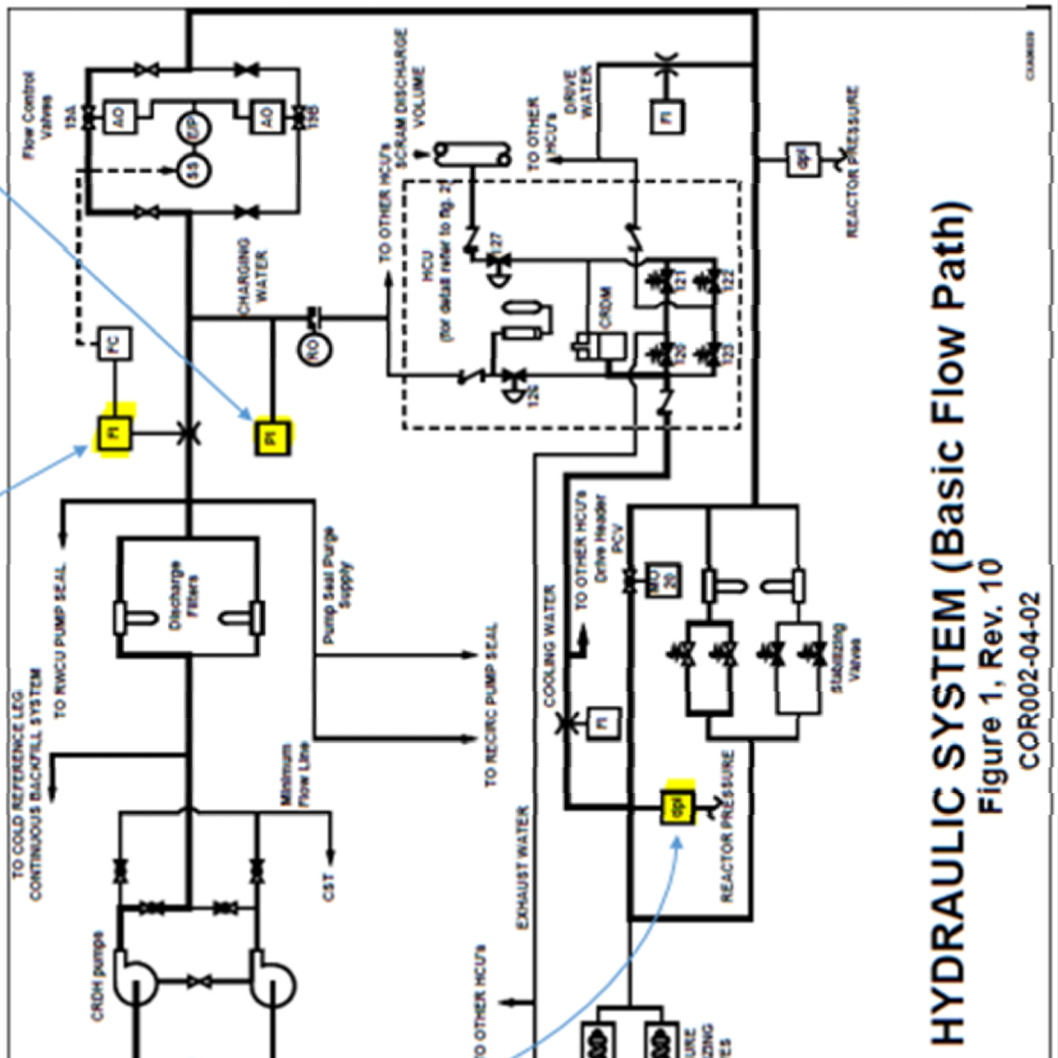
D. CRD System Total Flow → **higher**
Charging Water Pressure → **higher**

Answer: C. CRD System Total Flow → **higher**
Charging Water Pressure → **lower**

CRD-DPI-304
Cooling Water dP
Normally ~20 psid
Lowers to ~0 upon scram due to CRD FCV closing to minimum.

CRD-FI-310 CRD
Flow Control ACTUAL
High flow sensed here due to increase in charging water flow due to scram closes CRD FCVs to minimum to prevent pump runout; results in lower Cooling Water dP and flow

CRD-PI-302
Charging Water Pressure
Normally 1425-1475 psig
Lowers upon scram due to HCU accumulators discharging. Remains lower until scram is reset and accumulators recharge.



CRD HYDRAULIC SYSTEM (Basic Flow Path)
Figure 1, Rev. 10
COR002-04-02

ATTACHMENT 3 INFORMATION SHEET

1. DISCUSSION

1.1 FUNCTION

1.1.1 CRD System supplies and controls hydraulic pressure and flow to CRDMs in order to position control rods within the core and cool CRDMs while there is no drive motion. The system supplies water to rapidly insert control rods in response to manual or automatic signals, and water for normal rod drive insert and withdraw operations. The system also supplies seal water to reactor recirculation pumps and RWCU pumps, and supplies purge water to cold reference legs attached to condensing Chambers 3A and 3B.

1.2 OPERATING CHARACTERISTICS

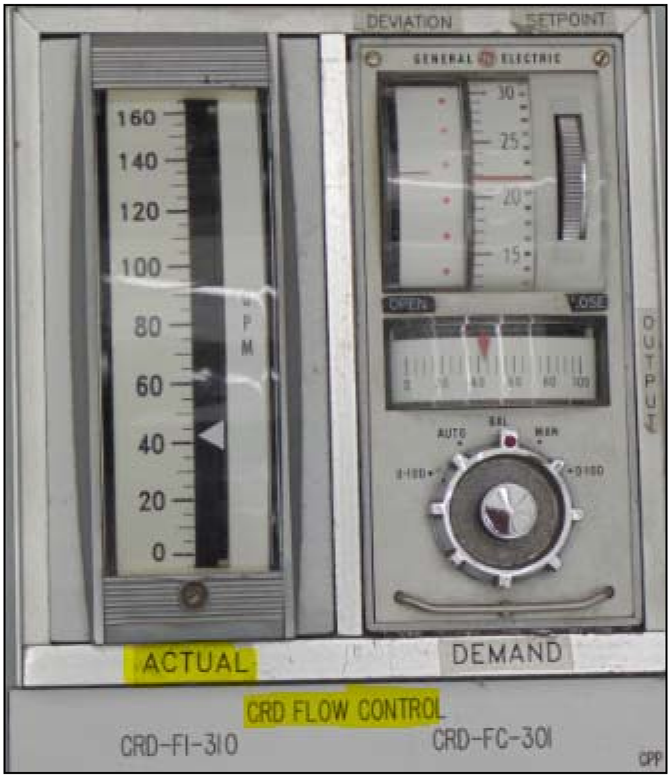
1.2.1 The Hydraulic System consists of two CRD pumps, two drive water filters, two flow control valves, one manual controller (local) for each flow control valve, one manual and one motor operated drive water pressure control valve, two sets of solenoid operated stabilizer valves, and piping to and from hydraulic control units (HCUs) for charging, driving, cooling, and exhaust water.

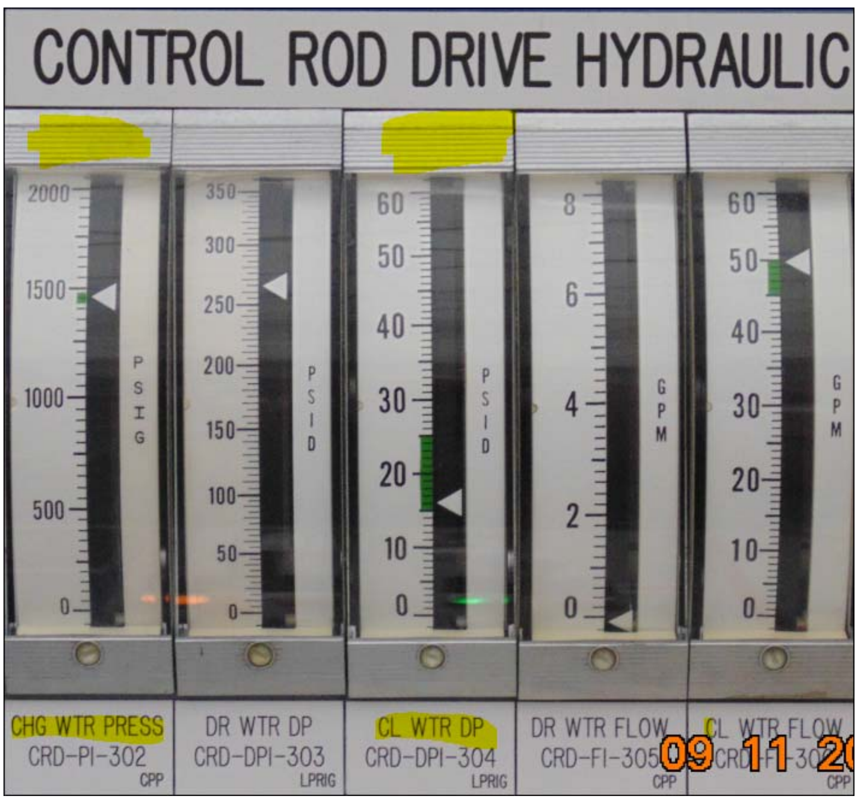
1.2.2 CRD pump suction is normally aligned to Condensate Storage Tank providing a supply of low oxygen concentration water to CRD System to reduce probability of CRD collet tube cracking. Alternate suction supply is demineralized water.

1.2.3 Flow Control - The accumulator charging pressure is maintained by a flow sensing controller and an air operated flow control valve. During normal operation, accumulator charging pressure is established upstream of flow control valve by the restriction of flow control valve. During a scram or ARI, the flow element upstream of accumulator charging header detects high flow in charging header and closes flow control valve to minimum flow. The pressure in charging header is monitored on Panel 9-5 with a pressure indicator and high pressure alarm. An accumulator charging pressure of 1400 to 1500 psig is required. Flow in charging header is required only during scram reset or during system startup. During normal operation, constant flow established through flow control valves is the sum of maximum water required to cool all drives, and water required by one drive to both insert and withdraw a control rod.

Lesson Number:	COR002-04-02	Revision:	30

SO-02b	6.	The CRDH pumps supply high pressure filtered water to pressurize hydraulic control unit (HCU) accumulators via the charging water header.
LO-05c		Charging water pressure is normally about 1425–1475 psig. Pressure indication is available locally and in the Control Room on Panel 9-5. If charging water pressure exceeds 1510 psig, a high pressure alarm is actuated in the Control Room. High charging water pressure could cause rapid acceleration of the CRDM during a scram, which could damage the CRDM.
LO-04a, 9g		During a scram, the HCU accumulators discharge and cannot be repressurized until the scram is reset. Two components help prevent the CRDH pump from going into a runout condition; the flow restricting orifice in the charging water line and the flow control valve.
LO-15b		The flow control valve closes after a reactor scram because of sensed high flow (the flow element is upstream of the charging water line).
		The flow restricting orifice helps prevent pump runout by limiting the charging water flow after a scram.
		Isolation valves in the charging water line on each HCU allow accumulator nitrogen recharging.
		A check valve in each HCU charging water line prevents the accumulators from discharging to CRDH if the CRDH pump fails.
Fig 6 LO-01e, 04k, 05g, 09c SO-02d	7.	A flow controller on Panel 9-5 allows remote control of the flow control valve. During normal operation, the flow control valve establishes a constant flow equal to the sum of the water to cool all the drives and the water required by one drive to both insert and withdraw a control rod. In the manual mode the operator sets a constant signal output. In the automatic mode the signal output is generated from the deviation between desired flow (set by the operator) and actual flow (sensed by the flow transmitter). The flow controller output is changed to signal air pressure at the electro-pneumatic (E/P) convertor. The signal air from the flow controller is called the remote loading signal. When the Foxboro Manual-Auto switch for a flow control valve is in the AUTO position, the signal air from the E/P convertor goes to the positioner. Signal air regulates the output of the positioner (motive air) to move the flow control valve.


DEVIATION
SETPOINT
GENERAL ELECTRIC
OPEN
OUTPUT
AUTO
BAL
MAN
ACTUAL
DEMAND
CRD FLOW CONTROL
CRD-FI-310
CRD-FC-301
CPP


CONTROL ROD DRIVE HYDRAULIC
CHG WTR PRESS
CRD-PI-302
DR WTR DP
CRD-DPI-303
CL WTR DP
CRD-DPI-304
DR WTR FLOW
CRD-FI-305
CL WTR FLOW

Examination Outline Cross-Reference	Level	RO
2.4.47 Ability to diagnose and recognize trends in an accurate and timely manner utilizing the appropriate control room reference material.	Tier#	3
	Group#	
	K/A #	G2.4.47
	Rating	4.2
	Revision	0
Revision Statement:		

Question 66

Reference Provided

LOCA conditions exist with the following conditions after a scram from 100% power:

- PMIS is UNAVAILABLE
- Drywell temperature 190°F, steady

10 minutes ago, RPV parameters were:

- Reactor pressure 1000 psig, slowly lowering
- Reactor water level -182” Fuel Zone on NBI-LR-1A

NOW, RPV parameters are:

- Reactor pressure 600 psig, slowly lowering
- Reactor water level -180” Fuel Zone on NBI-LR-1A

Which one of the following completes the statement below regarding the RPV level trend over the past 10 minutes and where actual level is with respect to Top of Active Fuel?

True water level inside the shroud has ___(1)___ (risen/lowered),

AND reactor water level is ___(2)___ (above/below) Top of Active Fuel NOW.

A. (1) risen
(2) above

B. (1) risen
(2) below

C. (1) lowered
(2) above

D. (1) lowered
   (2) below

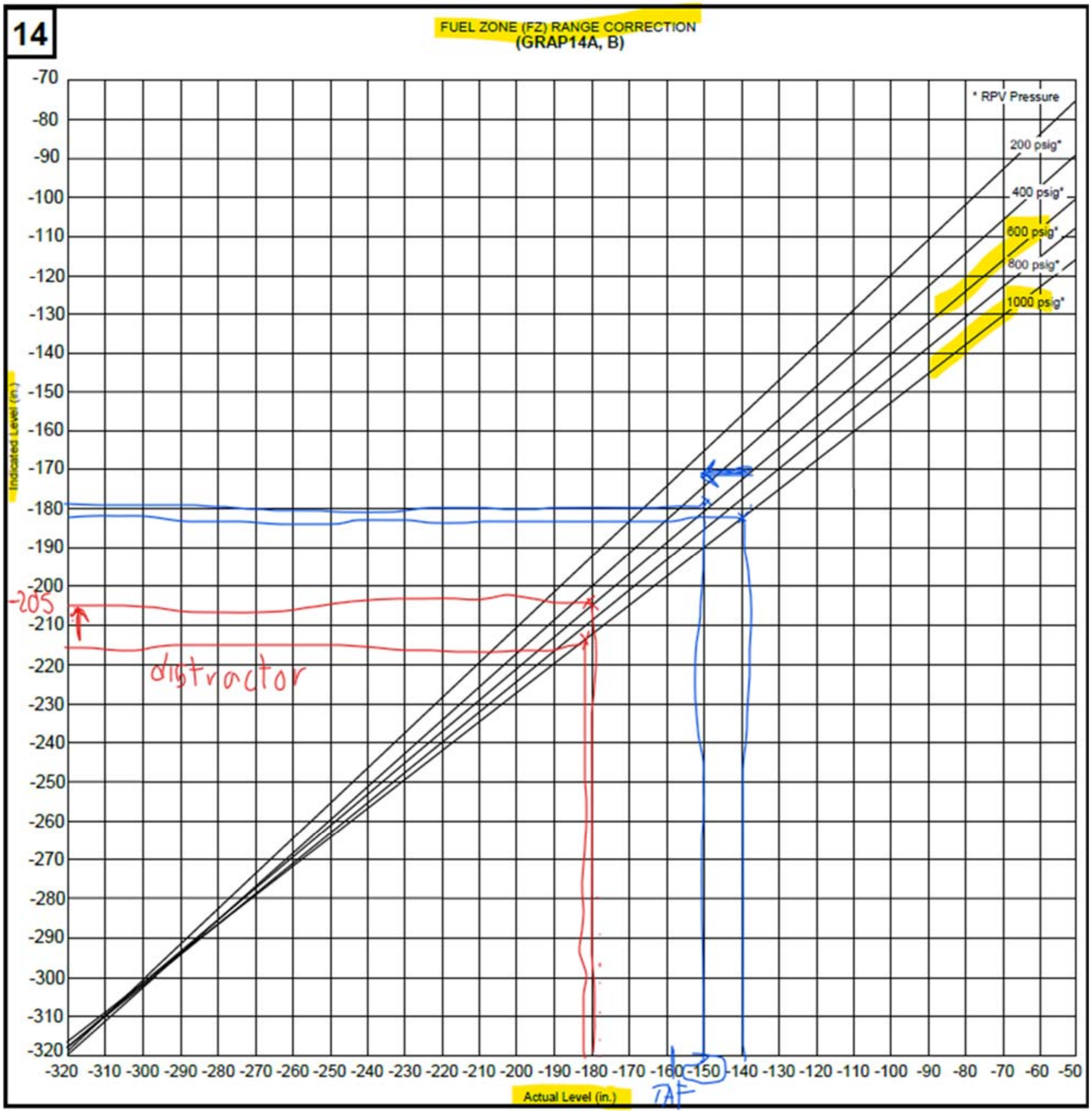
Answer: C
Explanation: This question is generic because it involves use of a graph used to determine actual reactor water in any plant condition. This question requires the examinee to determine the trend in RPV water level using EOP/SAG Graph 14, Fuel Zone Range Correction and diagnose current conditions as they pertain to RPV level with respect to TAF, adequate core cooling by submergence. PMIS is designed to provide Corrected Fuel Zone level, which is compensated for the effects of varying reactor pressure, and is the normal method of determining actual Fuel Zone water level. But in this case, PMIS is unavailable. The Fuel Zone instruments are calibrated to be accurate at 0 psig RPV pressure, 212°F in both the RPV and drywell with no jet pump flow. At higher pressure, water density in the variable leg is lower, so the dP as sensed by the differential pressure instrument is lower, resulting in an indicated level that is lower than actual level. At higher reactor pressures, as pressure lowers, indicated level and actual level converge. For the first set of conditions given, 1000 psig and -182" indicated Fuel Zone level, actual level is ~ -140". For the current conditions, 600 psig and -180" indicated Fuel Zone level, actual Fuel Zone level is ~-150". Although indicated water level has risen, actual water level has lowered. TAF is -158", so actual level -150" is above TAF. Drywell temperature is given as <200°F to ensure RPVSAT is in the safe zone, so Fuel Zone level indication is usable.
Distracters: Answer A part 1 is plausible because indicated level has risen. It is also plausible because if the Y-axis (indicated level) is confused with the X-axis (actual level). This would result in movement upward on Graph 14, and rising level along the Y-axis. It is wrong because actual level has lowered as RPV pressure has lowered. Part 2 is correct. Answer B part 1 is plausible and wrong for the same reason stated for distractor A. Part 2 is plausible to the examinee who has reversed axis believes actual level has risen because they would plot current level at ~-205", which is below TAF, -158". It is wrong because current actual level is ~ -150", above TAF. Answer D Part 1 is correct. Part 2 is plausible and wrong for the same reason stated for distractor B.

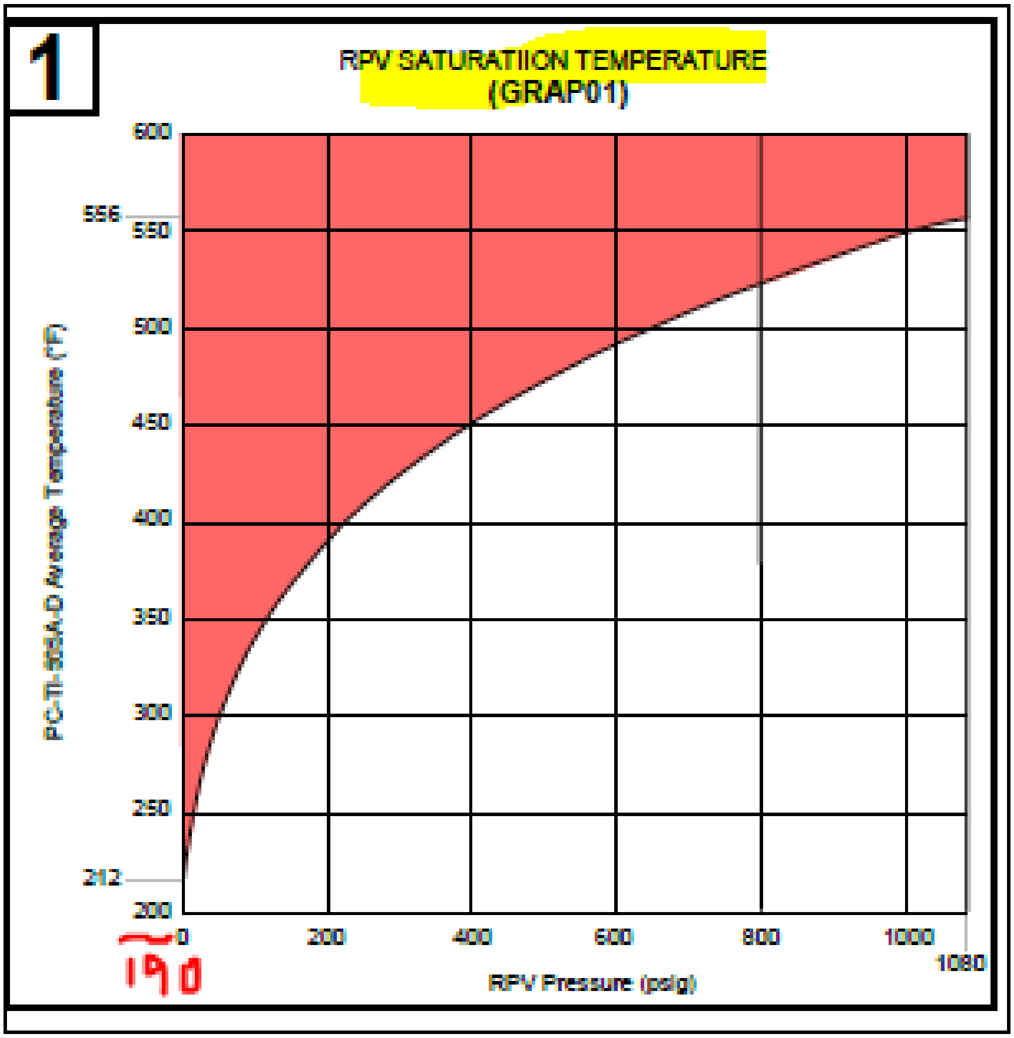
Technical References: EOP/SAG Graph 14 [Fuel Zone Range Correction](Rev 17), Lesson plan COR002-15-02 [Nuclear Boiler Instrumentation](Rev 28), EOP/SAG Graph 1 [RPV Saturation Temperature](Rev 17), AMP-TBD00 [PSTGs](Rev 10)		
References to be provided to applicants during exam: EOP/SAG Graph 14 [Fuel Zone Range Correction]		
Learning Objective: INT008-06-18 EO-3, Given plant conditions and the EOP and SAG Graphs Flowchart, determine if operation is within the allowed region of a graph.		
Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.41(b)(5),(10)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA Applicability:		
N/A		

Lesson Number:	COR002-15-02	Revision: 28

LO-04i, SO-06h 2) The Fuel Zone instruments are calibrated to be accurate at 0 psig RPV pressure, 212°F in both the RPV and drywell with no jet pump flow. Assuming actual level is held constant, the heating up of the water results in lower density. This causes the dP as sensed by the differential pressure instrument to raise, resulting in an indicated level that is lower than actual level.

14


FUEL ZONE (FZ) RANGE CORRECTION
(GRAP14A, B)
* RPV Pressure
200 psig*
400 psig*
600 psig*
800 psig*
1000 psig*
Indicated Level (in.)
Actual Level (in.)
-205
distractor
TAF


1
RPV SATURATIION TEMPERATURE
(GRAP01)
PC-TI-5S3A-D Average Temperature (°F)
600
556
550
500
450
400
350
300
250
212
200
0
200
400
600
800
1000
1080
RPV Pressure (psig)
190

Examination Outline Cross-Reference	Level	RO
2.1.37 Knowledge of procedures, guidelines, or limitations associated with reactivity management.	Tier#	3
	Group#	
	K/A #	G2.1.37
	Rating	4.3
	Revision	0
Revision Statement:		

Question 67 **From previous 2 NRC Exams 3/2017 ILT NRC Q#67**

Power is being reduced from 100% to 60% on your shift to perform a planned control rod sequence exchange.

IAW Procedure 2.0.3 [Conduct of Operations], what is the staffing requirement to fill the position of Reactivity Manager for this power change?

A. Additional SRO on shift with no concurrent duties

B. On shift SRO qualified WCO with concurrent duties

C. CRS with the Shift Manager present in the control room

D. CRS with a Reactor Engineer present in the control room

Answer: A
Explanation: Procedure 2.0.3 [Conduct of Operations] section 2.5.1 lists the staffing requirements for Reactivity Manager. It states an additional SRO with no concurrent duties must be present in the control room and act as Reactivity Manager during significant power changes. It defines significant power changes as startups, shutdowns, and ≥25% power changes using control rods. It gives specific examples of power changes that are not considered “significant” power changes where the on shift CRS may act a Reactivity Manager. The specific exemptions include routine power changes via Recirc flow for surveillances or load adjustments, rapid power reductions IAW procedure 2.1.10 [Station Power Changes], and <25% power change in one shift using control rods. For the case given, power reduction from 100% to 60% would be a 40% change. In this case, the power change does not fall into the category of any of the exemptions allowing the CRS to serve as Reactivity Manager; Therefore, an additional SRO with no concurrent duties is required.

Distracters:

Answer B is plausible because an SRO qualified WCO is an extra SRO, since minimum staffing only requires two SROs, the CRS and the SM. It is wrong because the WCO position is required for minimum control room operator staffing, along with RO and BOP licensed operators. The Reactivity Manager can have no concurrent duties, so he cannot also serve as WCO.

Answer C is plausible because the SM does not normally have to be present in the control room. The unprepared applicant might select this answer because he may know the CRS can, at times, fill the position of Reactivity Manager but not remember the conditions when an additional, dedicated SRO is required to be Reactivity Manager, or he might interpret the presence of the SM in the control room as an additional SRO, This answer is wrong because the case stated is for a planned, non-transient power reduction and involves a 40% power change on one shift. It is, therefore, a significant reactivity manipulation for which the CRS may not serve as Reactivity Manager.

Answer D is plausible because normally a Reactor Engineer would be present in the control room to provide guidance and oversight during significant power changes using control rods. The unprepared applicant might interpret the expertise available from reactor engineering sufficient to allow the CRS to concurrently fill the position of Reactivity Manager. This answer is wrong for the same reasons as stated for distractor C.

Technical References: Procedure 2.0.3 [Conduct of Operations](Rev 104)

References to be provided to applicants during exam: none

Learning Objective: INT032-01-03 EO-C1a7

Question Source:	Bank # **From previous 2 NRC Exams**	**3/2017 ILT NRC Q#67**
(note changes; attach parent)	Modified Bank #	
	New	
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(10)	
Level of Difficulty:	2	
SRO Only Justification:	N/A	

PSA applicability:

N/A

3/2017 ILT NRC Q#67

Examination Outline Cross-Reference	Level	RO
1. Conduct of Operations 2.1.37 Knowledge of procedures, guidelines, or limitations associated with reactivity management. (CFR: 41.1)	Tier#	3
	Group#	
	K/A #	G2.1.37
	Rating	4.3
	Revision	2
Revision Statement: Changed to memory/fundamental.		

Question 67

Power is being reduced from 100% to 60% on your shift to perform a planned control rod sequence exchange.

IAW Procedure 2.0.3 [Conduct of Operations], what is the staffing requirement to fill the position of Reactivity Manager for this power change?

A. Additional SRO on shift with no concurrent duties

B. On shift SRO qualified WCO with concurrent duties

C. CRS with the Shift Manager present in the control room

D. CRS with a Reactor Engineer present in the control room

Answer: A. Additional SRO on shift with no concurrent duties

2.4.3.20 Ensure Operators on-shift conduct a proper shift turnover.

2.4.3.21 Maintain cognizance and coordinate with the WCO and/or WCCA, as necessary, to ensure surveillances scheduled for Operations are performed.

2.4.3.22 Conduct an End of Shift Brief including at a minimum, shift accomplishments, plant conditions, noted discrepancies, and lessons learned.

2.4.3.23 Authorize all maintenance planned or in-progress on the shift when the WCCA is not present (i.e., backshifts and weekends) and the WCO does not possess a SRO license.

2.4.3.24 Assist in on-shift training of Operations Department personnel.

2.5 REACTIVITY MANAGER Ⓟ[33]

2.5.1 A Senior Reactor Operator (SRO) shall be designated as the Reactivity Manager as defined below: Ⓟ[1,6,7]

2.5.1.1 CRS may fulfill this function in the following situations:

a. Performance of rapid power reduction per Procedure 2.1.10.

b. Power adjustments with reactor recirculation for routine load changes and surveillance testing.

c. Control rod manipulations resulting in power changes < 25% over a shift.

2.5.1.2 A SRO with no concurrent duties shall assume the role of Reactivity Manager during significant reactivity manipulations or power changes including plant startup or shutdown, or any power changes ≥ 25% with control rods.

2.5.2 Reactivity Manager shall provide direct oversight of all reactivity manipulations performed by CRO-Reactor Operator (CRO-RO) and ensure all requirements and expectations associated with the standard for reactivity manipulation with control rods are carried out by CRO-RO and Reactor Engineering personnel. Ⓟ[6,7]

2.5.2.1 For abnormal conditions, the CRS, when acting as the Reactivity Manager, has to balance the priorities of new events against the importance of reactivity changes. It is recognized that the CRS has multiple duties and responsibilities during a transient or abnormal, emergency, or EOP condition. CRS has at his discretion the level of the Reactivity Manager function he will perform during these emergent conditions.

12. CONTROL ROOM AND STATION SHIFT STAFFING REQUIREMENTS Ⓟ[1]

NOTE 1 – To prevent any person with an inactive license from being assigned a Control Room duty station or from performing a manipulation that would change reactivity, lists of active and inactive licensed personnel are available in the Control Room and WC.

NOTE 2 – Higher grade qualified Licensed Operators may take the place of lower grade Licensed or Non-Licensed Operators.

12.1 The minimum shift staffing shall include the following personnel:

12.1.1 Two active Licensed SROs (SM and CRS). Ⓟ[2]

12.1.2 Three active Licensed Control Room Operators (RO, BOP, and WCO).

12.1.3 Three Non-Licensed Nuclear Plant Operators.

NOTE – The Chemistry and Radiation Protection support and Dose Assessor cannot be the same individual.

12.1.4 One person trained and qualified to provide Chemistry and Radiation Protection support, as required by the CNS Emergency Plan and Technical Specifications.

12.1.5 One person trained and qualified as a Dose Assessor, as required by the CNS Emergency Plan.

NOTE – STE position is not required in MODE 4 or 5.

12.1.6 One STE.

NOTE – Shift Communicator cannot have any other license required duties.

12.1.7 One person designated as Shift Communicator.

12.1.8 Two personnel trained and qualified as Utility/Fire Brigade.

12.1.9 In MODE 1, 2, or 3, the additional following requirements shall be met:

12.1.9.1 Two active Licensed Operators shall be in the Control Room (one of which must be an active Licensed SRO). Ⓟ[2]

12.1.9.2 One active Licensed SRO or RO shall be ATC in the Control Room.

12.1.9.3 One active Licensed Operator designated as Fire Brigade Leader. The Fire Brigade shall consist of five people, three of which shall be Operations personnel. The remaining two members may be from other departments.

a. The two remaining Fire Brigade members are typically staffed by Utility personnel. Filling these positions from Operations minimum shift staffing will reduce staffing levels below those assumed in Procedure 5.4FIRE-S/D required positions.

12.1.9.4 In the event that any member of the minimum operating shift <u>and/or</u> Fire Brigade Crew is absent or incapacitated due to illness or injury, a qualified replacement shall be designated to report on-site within 2 hours.

12.1.10 In MODE 4 or 5, the additional following requirements shall be met:

12.1.10.1 An active Licensed SRO or RO shall be at the controls in the Control Room.

12.1.10.2 One active Licensed Operator designated as Fire Brigade Leader. The Fire Brigade shall consist of five people, three of which shall be Operations personnel. The remaining two members may be from other departments.

12.1.10.3 Two people shall be in the Control Room at all times per CNS Security Plan.

12.1.10.4 In the event that any member of the minimum operating shift and/or Fire Brigade Crew is absent or incapacitated due to illness or injury, a qualified replacement shall be designated to report on-site within 2 hours.

12.2 From the time that MODE 2 is entered, until first reactor feedwater pump discharge valve is open, the following additional Operator coverage is required:

12.2.1 One active Licensed SRO to observe all Panel 9-5 operations to ensure reactivity manipulations are in accordance with approved procedures.

12.2.2 One active Licensed Operator dedicated to Concurrent Verification of control rod movements to provide continuous availability for rod verifications. He shall remain independent from the duty Crew, and manipulate controls only if absolutely necessary and at the direction of the duty Crew. Ⓟ[10]

12.2.3 One Non-Licensed Nuclear Plant Operator to assist the duty Crew during times when the work load prevents the duty Crew from performing manipulations in a timely manner. When not needed to assist the duty Crew, he shall tour the plant, being observant to potential plant problems.

10.3 REFUELING OR REACTOR CORE ALTERATION STAFFING REQUIREMENTS

10.3.1 An active Licensed SRO with no other concurrent duties shall be directly in charge of any refueling operation or reactor core alteration.

10.3.2 An active Licensed SRO or RO with no other concurrent duties shall be directly in charge of operations involving the handling of irradiated fuel within an Item Control Area (ICA).

10.3.3 An active Licensed SRO with no other concurrent duties shall be directly in charge of operations involving the handling of irradiated fuel from one Item Control Area (ICA) to another.

10.4 Inactive Licensed RO or SRO may only perform activities or stand watch duties allowed by Non-Licensed Operators unless under direction and presence of an active Licensed Operator.

10.4.1 Inactive Licensed Operators may perform Concurrent and Independent Verification of controls and equipment, except for verifying control rod movements as described in Step 10.2.2.

11. WATCH-STANDER QUALIFICATION REQUIREMENTS

11.1 Operations personnel shall be qualified to the following TQDs for the associated watch position.

11.1.1 Shift Manager - TQD 216.

11.1.2 Control Room Supervisor - TQD 207.

11.1.3 Control Room Operator - TQD 203.

11.1.4 Shift Technical Engineer - TQD 528.

11.1.5 NLO - Turbine Building - TQD 201TURB.

11.1.6 NLO - Reactor Building - TQD 201RX.

11.1.7 NLO - Radwaste - TQD 201RW.

11.1.8 Fire Brigade Leader - TQD 511.

11.1.9 Fire Brigade Member - TQD 511.

11.1.10 Shift Communicator - TQD 631.

11.2 If an Operator becomes temporarily disqualified to a watch position, the AOM-Shift or Shift Manager shall notify the individual of the disqualification and watch position(s) affected, and perform one of the following:

11.2.1 Ensure the Licensed Operator Restriction database is updated if condition is medical in nature.

12.3 REFUELING OR REACTOR CORE ALTERATION STAFFING REQUIREMENTS

12.3.1 An active Licensed SRO (Refuel Floor SRO) with no other concurrent duties shall be directly in charge of core alterations.

12.3.2 An active Licensed SRO or RO with no other concurrent duties shall monitor plant conditions (e.g., SRMs) which could impact refueling operations.

12.4 IRRADIATED FUEL MOVEMENT STAFFING REQUIREMENTS

12.4.1 An active Licensed RO with no other concurrent duties shall be directly in charge of operations involving the handling of irradiated fuel other than core alterations.

12.5 Inactive Licensed RO or SRO may only perform activities or stand watch duties allowed by Non-Licensed Operators unless under direction and presence of an active Licensed Operator.

12.5.1 Inactive Licensed Operators may perform Concurrent and Independent Verification of controls and equipment, except for verifying control rod movements as described in Step 12.2.2.

13. WATCH-STANDER QUALIFICATION REQUIREMENTS

13.1 Operations personnel shall be qualified to the following TQDs for the associated watch position.

- Shift Manager - TQD 216.
- Control Room Supervisor - TQD 207.
- Control Room Operator - TQD 203.
- Shift Technical Engineer - TQD 528.
- NLO - Turbine Building - TQD 201TURB.
- NLO - Reactor Building - TQD 201RX.
- NLO - Radwaste - TQD 201RW.
- Fire Brigade Leader - TQD 511.
- Fire Brigade Member - TQD 511.
- Shift Communicator - TQD 631.

13.2 If an Operator becomes temporarily disqualified to a watch position, the AOM-Shift or Shift Manager shall notify the individual of the disqualification and watch position(s) affected, and perform one of the following:

13.2.1 Ensure Licensed Operator Restriction database is updated if condition is medical in nature.

13.2.2 Ensure Training Qualification Matrix is updated if condition is dictated by qualification issues.

Examination Outline Cross-Reference	Level	RO
2.4.49 Ability to perform without reference to procedures those actions that require immediate operation of system components and controls.	Tier#	3
	Group#	
	K/A #	G2.4.49
	Rating	4.6
	Revision	0
Revision Statement:		

Question 68

There are operational circumstances when operators must perform Immediate Operator Actions, as defined per Procedure 2.0.1.2 [Operations Procedure Policy], without reference to procedures or directions from the CRS.

Which statement represents one of those circumstances?

A. When an EOP directs performing the action.

B. When Technical Specifications direct a scram.

C. When an Alarm procedure directs performing the action.

D. When an Abnormal procedure directs performing the action.

Answer: D

Explanation:
Abnormal and Emergency (Non-EOP) procedures contain Immediate Operator Actions which the control room operator has committed to memory. Should a condition exist that requires Immediate Operator Actions, Procedure 2.0.1.2 directs performing the action without use of procedures. Procedure 2.0.1.2 Attachment 1 lists all of the approved Immediate Operator Actions, and they are only contained in Abnormal/Emergency Procedures.

Distracters:
Answer A is plausible because actions are directed to be taken without use of the procedure but they are not immediately performed from memory. The examinee who recalls immediately performing actions directed from EOPs would select this answer. This answer is incorrect because EOPs do not contain immediate operator actions. Actions are taken per the EOPs without the control room operator having the procedure in hand, but the actions are directed by the CRS.

Answer B is plausible because Technical Specifications have completion times to be taken immediately, but per TS immediate means to pursue without delay and in a controlled manner. This answer is incorrect because no actions are taken immediately from Technical Specifications.

Answer C is plausible because actions can be performed immediately after entering the procedure. The examinee who recalls scram actions contained in alarm procedures may believe the action can be taken prior to entering the alarm procedure would select this answer. This answer is incorrect because alarm procedures do not contain immediate operator actions.

Technical References: Procedure 2.0.1.2 [Operations Procedure Policy](Rev 47)

References to be provided to applicants during exam: none

Learning Objective: INT032-01-03 EO- G1f, Discuss the following as described in Procedure 2.0.1.2, Operations Procedure Policy: Attachment 1, Immediate Operator Actions

Question Source:	Bank #	4/2015 ILT NRC Q#75
(note changes; attach parent)	Modified Bank #	
	New	
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(10)	
Level of Difficulty:	2	
SRO Only Justification:	N/A	

PSA Applicability:
N/A

4/2015 ILT NRC Q#75

Question: 75

There are operational circumstances when operators must perform immediate operator actions without reference to procedures.

Which statement represents one of those circumstances?

A. When an EOP directs performing the action.

B. When Technical Specifications direct a scram.

C. When an Alarm procedure directs performing the action.

D. When an Abnormal procedure directs performing the action.

Answer:
D. When an Abnormal procedure directs performing the action.

6. ABNORMAL AND EMERGENCY PROCEDURES® [5]

6.1 ABNORMAL AND EMERGENCY PROCEDURE USAGE - GENERAL

6.1.1 APs and EPs shall be classified as Continuous Use. The exception to Continuous Use is when performing Immediate Operator Actions from memory as prescribed in Step 6.5.1.

6.1.2 In general, APs address less severe conditions than EPs. An exception to this is electrical casualty procedures that are grouped together as 5.3 series for improved human factoring.

6.1.3 APs and EPs use a numeric-alpha numbering scheme. The alpha is a casualty or system descriptor. All APs are 2.4 series. EPs numeric series is defined below.

6.1.3.1 5.1 series typically address whole plant or large area emergencies.

6.1.3.2 5.2 series typically address individual piping system emergencies.

PROCEDURE 2.0.1.2 REVISION 47 PAGE 3 OF 15

6.5 IMMEDIATE OPERATOR ACTIONS

6.5.1 Immediate Operator Actions (IOAs) shall be performed from memory and subsequently verified with the applicable procedure.Ⓟ[3]

6.5.2 IOAs are developed using following criteria:

6.5.2.1 IOAs are activities that stop the degradation of abnormal or emergency conditions and mitigate their consequences by:

a. Ensuring reactor is in a safe condition with adequate core cooling.

b. Ensuring Reactor Coolant System pressure boundary is intact.

c. Ensuring adequate power sources are available.

d. Ensuring containment and exhaust systems (e.g., associated ventilation, SBGT, ERP) are operating properly to prevent uncontrolled release of radioactivity.

6.5.2.2 IOAs must be capable of performance within a reasonable time in order to stop event degradation and mitigate event consequences. The <u>development</u> of IOAs is based on a "reasonable time" being ~ 1 minute. The value of 1 minute is only for the purpose of developing IOAs and shall not be used as an Operator performance standard.

ATTACHMENT 1 IMMEDIATE OPERATOR ACTIONS

ATTACHMENT 1 IMMEDIATE OPERATOR ACTIONS

1. PROCEDURE 2.4CSCS

1.1 IF HPCI initiated, THEN perform following:

1.1.1 Ensure AUXILIARY OIL PUMP control switch in START.

1.1.2 Press and hold TURBINE TRIP button.

1.1.3 AFTER turbine stops, THEN place AUXILIARY OIL PUMP in PULL-TO-LOCK.

1.1.4 Release TURBINE TRIP button.

2. PROCEDURE 2.4MC-RF

2.1 IF RPV level cannot be maintained above +12" on Narrow Range Instruments, THEN SCRAM and concurrently enter Procedure 2.1.5.

3. PROCEDURE 2.4RR

3.1 IF both RR pumps are tripped and reactor power > 1% rated thermal, THEN perform following:

3.1.1 **SCRAM**.

3.1.2 Enter Procedure 2.1.5.

3.2 IF abnormal neutron flux oscillations are observed while operating in the Stability Exclusion Region, THEN perform following:

3.2.1 **SCRAM**.

3.2.2 Enter Procedure 2.1.5.

3.3 IF recirculation flow is not stable, THEN perform following:

3.3.1 IF recirculation flow is rising, THEN perform following:

3.3.1.1 Press SCOOPTUBE LOCKOUT button.

3.3.1.2 IF flow still has not stabilized, THEN trip affected RR pump and enter Attachment 1.

3.3.2 IF recirculation flow is lowering, THEN press SCOOPTUBE LOCKOUT button.

ATTACHMENT 1 IMMEDIATE OPERATOR ACTIONS

4. PROCEDURE 2.4RXLVL

4.1 **If either of following occur at any time, SCRAM and concurrently enter Procedure 2.1.5:**

4.1.1 **RPV level cannot be maintained above +12" on narrow range instruments.**

4.1.2 **RPV level cannot be maintained below +50" on narrow range instruments.**

5. PROCEDURE 2.4RXPWR

5.1 IF reactor power rising, THEN reduce power per Procedure 2.1.10.

5.2 IF power rise not terminated, THEN **SCRAM** and concurrently enter Procedure 2.1.5.

5.3 **IF reactor power is undergoing significant uncontrolled oscillations, THEN SCRAM and concurrently enter Procedure 2.1.5.**

6. PROCEDURE 2.4VAC

6.1 For lowering condenser vacuum:

6.1.1 Reduce power per Procedure 2.1.10 to maintain vacuum ≥ 23" Hg.

6.1.2 **IF vacuum cannot be maintained ≥ 23" Hg, THEN:**

6.1.2.1 **IF Annunciator 9-5-2/C-4 clear, THEN SCRAM and enter Procedure 2.1.5.**

6.1.2.2 Trip Main Turbine.

6.1.2.3 IF reactor not scrammed, THEN enter Procedure 2.2.77.

7. PROCEDURE 2.4EX-STM

7.1 IF reactor power rises to > 100% RTP, THEN reduce power to maintain ≤ 100% RTP per Procedure 2.1.10.

8. PROCEDURE 2.4TOX

8.1 Essential Control Room personnel don self-contained breathing apparatus.

ATTACHMENT 1 IMMEDIATE OPERATOR ACTIONS

9. PROCEDURE 5.2REC

9.1 IF REC HEADER PRESSURE ≤ 62 psig, THEN start available REC pumps.

9.2 IF REC HEADER PRESSURE not restored, THEN close following valves:

9.2.1 REC-AO-710, RWCU NON-REGEN HX INLET.

9.2.2 REC-MO-1329, AUGMENTED RADWASTE SUPPLY.

10. PROCEDURE 5.3AC120

10.1 IF CDP-1B de-energized, THEN fully open:

10.1.1 MS-BV-1A, SJAE A STM SUPP BYP VLV.

10.1.2 MS-BV-1B, SJAE B STM SUPP BYP VLV.

11. PROCEDURE 5.3AC480

11.1 IF 480V Bus 1G de-energized, THEN fully open:

11.1.1 MS-BV-1A, SJAE A STM SUPP BYP VLV.

11.1.2 MS-BV-1B, SJAE B STM SUPP BYP VLV.

12. PROCEDURE 5.5SECURITY

12.1 If in MODE 1, 2, or 3 and CNS Security enters Code Red or Black:

12.1.1 Immediately dispatch designated Operator to R-903-NE and commence actions of Attachment 12.

12.1.2 **SCRAM** and enter Procedure 2.1.5.

12.1.3 At Panel 9-4, open RCIC-MO-21, PUMP DISCH TO RX VLV.

12.1.4 Ensure following has been performed by Security:

12.1.4.1 Place Breaker 8, PANEL 9-33 (SRV emergency power), on 125 VDC Panel BB2 (C-903-B BATT RM), to OFF.

12.1.4.2 Place Breaker 15, PANEL 9-45 (SRV normal power), on 125 VDC Panel AA2 (C-903-A BATT RM), to OFF.

Examination Outline Cross-Reference	Level	RO
2.3.4 Knowledge of radiation exposure limits under normal or emergency conditions.	Tier#	3
	Group#	
	K/A #	G2.3.4
	Rating	3.2
	Revision	0
Revision Statement:		

Question 69

IAW Procedure 9.ALARA.1 [Personnel Dosimetry and Occupational Radiation Exposure Program]…

What is the highest dose that can be received **on-site** under normal plant conditions by an individual in a calendar-year **without** having to acquire written authorization for a dose extension?

A. 1000 mrem

B. 2000 mrem

C. 3000 mrem

D. 4000 mrem

Answer: B
Explanation: This is a modified version of 3/2017 ILT NRC Q#72 that has a different correct answer due to a procedure change. The annual limit that requires written authorization to exceed has since been changed from 1000 mrem to 2000 mrem. IAW procedure 9.ALARA.1 section 5, written approval to exceed 2000 mrem in a calendar year must be obtained from an individual's supervisor and the RP Technical Supervisor. Therefore, 2000 mrem is the highest dose that can be received annually without written authorization.
Distracters: Answer A is plausible because it was the previous limit listed in procedure 9.ALARA.1 that required a level of written authorization to exceed. It is wrong because written

authorization from the individual's supervisor and the RP Technical Supervisor is only required to exceed 2000 mrem.

Answer C is plausible because it is a value listed in procedure 9.ALARA.1 step 5.5 that requires a level of written authorization to exceed. It is wrong because one level of written authorization would have already been required to reach 3000 mrem, since it is greater than 2000 mrem.

Answer D is plausible because it is the overall administrative annual dose limit listed in procedure 9.ALARA.1 section 5. It is wrong because two levels of written authorization would have already been required to reach 4000 mrem, and 4000 mrem is not to be exceeded.

Technical References: procedure 9.ALARA.1 section 5 (Rev 48)

References to be provided to applicants during exam: none

Learning Objective: INT032-01-15 EO-D1h

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	3/2017 ILT NRC Q#72
	New	
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(12)	
Level of Difficulty:	2	
SRO Only Justification:	N/A	

PSA applicability:

N/A

3/2017 ILT NRC Q#72

Question 72

IAW Procedure 9.ALARA.1 [Personnel Dosimetry and Occupational Radiation Exposure Program]…

What is the highest dose that can be received **on-site** under normal plant conditions by an individual in a calendar-year **without** having to acquire written authorization for a dose extension?

A. 1000 mrem

B. 2000 mrem

C. 3000 mrem

D. 4000 mrem

Answer: A. 1000 mrem

5.2 Prior to dose extension, requesting supervisor perform following:

5.2.1 Evaluate dose equalization in the department.

5.2.2 Evaluate other personnel qualifications to perform task.

5.2.3 Evaluate other means to reduce dose.

5.3 Prior to allowing worker to exceed 2000 mrem TEDE annually, obtain verification of worker's current year exposure prior to allowing a worker to exceed 2000 mrem TEDE for the year.

5.4 Any of following may be used for verification:

- NRC Form 5 or equivalent provided by either worker or licensee(s) providing monitoring for each monitoring period.
- NRC Form 4 or equivalent signed by the person.
- Electronic, telephone, or facsimile transfer of exposure data provided by the licensee(s) providing the monitoring.

5.5 Extend a Radiation Workers' administrative TEDE Administrative Dose Guideline (ADG) to the guidelines described in the following table, after obtaining the indicated approvals.

EXPOSURE GUIDELINE	REQUIREMENTS	REQUIRED APPROVALS
> 2000 mrem and ≤ 3000 mrem per year	No undocumented dose for the current year	• Individual's Supervisor • RP Technical Supervisor/Designee
> 3000 mrem and ≤ 4000 mrem per year	No undocumented dose for the current year	• Individual's Supervisor • RP Technical Supervisor/Designee • Radiation Protection Manager/Designee • GMPO/Designee

5.6 Document authorization of increasing administrative dose for worker on CNS RP-9, Authorization to Exceed Administrative Radiation Dose limits.

Examination Outline Cross-Reference	Level	RO
2.4.3 Ability to identify post-accident instrumentation.	Tier#	3
	Group#	
	K/A #	G2.4.3
	Rating	3.7
	Revision	0
Revision Statement:		

Question 70 **From previous 2 NRC Exams** 9/2018 ILT NRC Q#74

Which symbol is used on control room panels to identify Post-Accident Monitoring instrumentation required by Reg. Guide 1.97 and governed by TS 3.3.3.1 [PAM Instrumentation]?

A. ◆

B. ▲

C. ■

D. ●

Answer: A

Explanation:
Black diamonds on meter/recorder labels and near isolation valve indicating lights are used to identify the indication as Reg Guide 1.97/Post-Accident Monitoring instrumentation.

Distracters:
Answer B is plausible because it reflects a simple symbol, like the correct answer. It is wrong because it is a triangle, not a diamond.

Answer C is plausible because it reflects a simple symbol, like the correct answer. It is wrong because it is a square, not a diamond.

Answer D is plausible because it reflects a simple symbol, like the correct answer. It is wrong because it is a circle, not a diamond.		
Technical References: Procedure 3.18 [Regulatory Guide 1.97 Instrumentation](Rev 11), procedure 2.0.1 [Plant Operations Policy](Rev 65)		
References to be provided to applicants during exam: none		
Learning Objective: INT0320103 EO-3, State how Reg. Guide 1.97 instrumentation is identified in the Control Room.		
Question Source:	Bank # **From previous 2 NRC Exams**	9/2018 ILT NRC Q#74
(note changes; attach parent)	Modified Bank #	
	New	
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(7),(10)	
Level of Difficulty:	2	
SRO Only Justification:	N/A	
PSA Applicability		
N/A		

From 9/2018 NRC Exam

Examination Outline Cross-Reference	Level	RO
G 2.4.3 Ability to identify post-accident instrumentation. (CFR: 41.6 / 45.4)	Tier #	3
	Group #	
	K/A #	G2.4.3
	Rating	3.7
	Revision	0
Revision Statement:		

Question 74

Which symbol is used on control room panels to identify Post-Accident Monitoring instrumentation required by Reg. Guide 1.97 and governed by TS 3.3.3.1 [PAM Instrumentation]?

A. ◆

B. ▲

C. ■

D. ●

Answer: A

2.8 RegGuide 1.97 equipment is designated in the "SPECIFICATION" field in the Master Data. Those items that have more than one RegGuide 1.97 function shall be listed with the most limiting Category (i.e., a variable having a C-3 and an E-1 function will be listed as "RG 1.97 E-1").

2.9 Control Room indicators for Categories 1 and 2, Types A, B, and C variables, are marked with black diamonds on the panels to identify them as RegGuide 1.97 instruments.

2.10 RegGuide 1.97 instruments are classified per Procedure 3.4. In general, the following rules apply:

2.10.1 Category 1 variables are classified ESSENTIAL throughout the instrumentation channel. Instruments located in harsh environments as defined in Procedure 3.12.7 are classified EQ.

2.10.2 Category 2 variables are classified NON-ESSENTIAL. However, instruments located in harsh environments as defined in Procedure 3.12.7 are classified EQ.

2.10.2.1 Category 2 variables may have non-RegGuide 1.97 functions that require an ESSENTIAL or EQ classification.

2.10.3 Category 3 variables are classified NON-ESSENTIAL.

2.10.3.1 Category 3 variables may have non-RegGuide 1.97 functions that require an ESSENTIAL or EQ classification.

2.11 RegGuide 1.97 instruments shall be included in the CNS Calibration Program per the guidelines of Procedure 0.38.

2.12 DEFINITIONS

2.12.1 Type A - Those variables to be monitored that provide the primary information required to permit the Control Room Operators to take the specified manually controlled actions for which no automatic control is provided and that are required for safety systems to accomplish their safety function for design basis accident events.

2.12.2 Type B - Those variables to be monitored that provide the Control Room Operator information to assess the process of accomplishing or maintaining critical safety functions (i.e., reactor control, core cooling, Reactor Coolant System OPERABILITY, primary reactor containment OPERABILITY, and radioactive effluent control).

2.12.3 Type C - Those variables to be monitored that provide the Control Room Operator information to monitor (1) the extent to which parameters, which have the potential for causing a breach of the primary reactor containment, have exceeded the design basis values, or (2) that the in-core fuel clad, Reactor Coolant System pressure boundary, or primary reactor containment may have been breached.

2.2 Operations personnel performing Independent Verification for other than Tagging Orders shall be qualified as follows:

2.2.1 For equipment located in the Main Control Room, Independent Verifier shall be certified as a Licensed Operator (Active or Inactive) or STE.

2.2.2 For equipment located outside the Main Control Room, Independent Verifier shall be certified as a Licensed Operator (Active or Inactive), STE, Station Operator or Non-OPS Independent Verifier.

2.3 Operations personnel performing Concurrent Verification shall be qualified as follows:

2.3.1 For equipment located in the Main Control Room, Concurrent Verifier shall be certified as a Licensed Operator (Active or Inactive) or STE.

2.3.2 For equipment located outside the Main Control Room, Concurrent Verifier shall be certified as a Licensed Operator (Active or Inactive), STE, or Station Operator.

2.4 CNS personnel should route all draining operations to equipment drains, except CW/SW Systems or when otherwise deemed necessary, to minimize FDN in-leakage.

3. REGULATORY GUIDE 1.97 INSTRUMENTS

3.1 NRC requires certain Regulatory Guide 1.97 instruments used in Control Room be identified to Control Room Operators.

3.1.1 These instruments are identified by a small black diamond in lower left-hand corner of nameplate for instrument.

3.2 These instruments are to be considered more reliable and accurate during accident conditions because they meet certain criteria for EQ requirements, seismic requirements, redundancy requirements, power requirements, channel availability, range, and display requirements.

4. ADMINISTRATIVE CONTROL OF PC ISOLATION VALVES PER NOTE 1 TO LCO 3.6.1.3

4.1 Isolation valves closed to satisfy LCO 3.6.1.3 may be re-opened on an intermittent basis under following administrative controls:

NOTE – "Valve controls" is location at which valve closure can be assured.

4.1.1 A person shall be stationed at valve controls while valve is open.

4.1.2 If valve is being controlled outside of Control Room, person at valve controls shall be in continuous communication with Control Room.

Lesson Title: OPS CNS Administrative Procedures Conduct of Operations and General Alarm Procedures (Formal Classroom/Pre-OJT Training)	
Lesson No.: INT032-01-03	Revision Number: 10

I. PURPOSE

The purpose of this lesson is to make operators aware of requirements, standards, cautions, responsibilities, etc. as required by their job position and program objectives.

II. BRIEF DESCRIPTION

1. This lesson may be taught as a whole or by individual procedure (as applicable) as required by the program utilizing this lesson.
2. The text for this lesson is the procedure itself.
3. Procedures copied for training purposes must be stamped with a "For Information Only" stamp.
4. Portions of this lesson may cover only select areas of the associated procedure(s) that are related to the enabling objectives.
5. The remainder of the material contained within the procedures is to be self-studied by the student.

III. LESSON

A. Procedure 2.0.1, Plant Operations Policy

1. Discuss the purpose of this procedure.

EO A.1.a. — 2. Discuss the PRECAUTIONS AND LIMITATIONS section of this procedure.

EO A.1.c — 3. Discuss the REGULATORY GUIDE 1.97 INSTRUMENTS section of this procedure.

EO A.3 — a. More reliable during accidents.

b. Meet EQ, seismic, redundancy, power, availability, range, and display requirements.

Reqd. for plant shutdown, post - accident monitors — c. Small, black diamonds in lower left-hand corner used for identification.

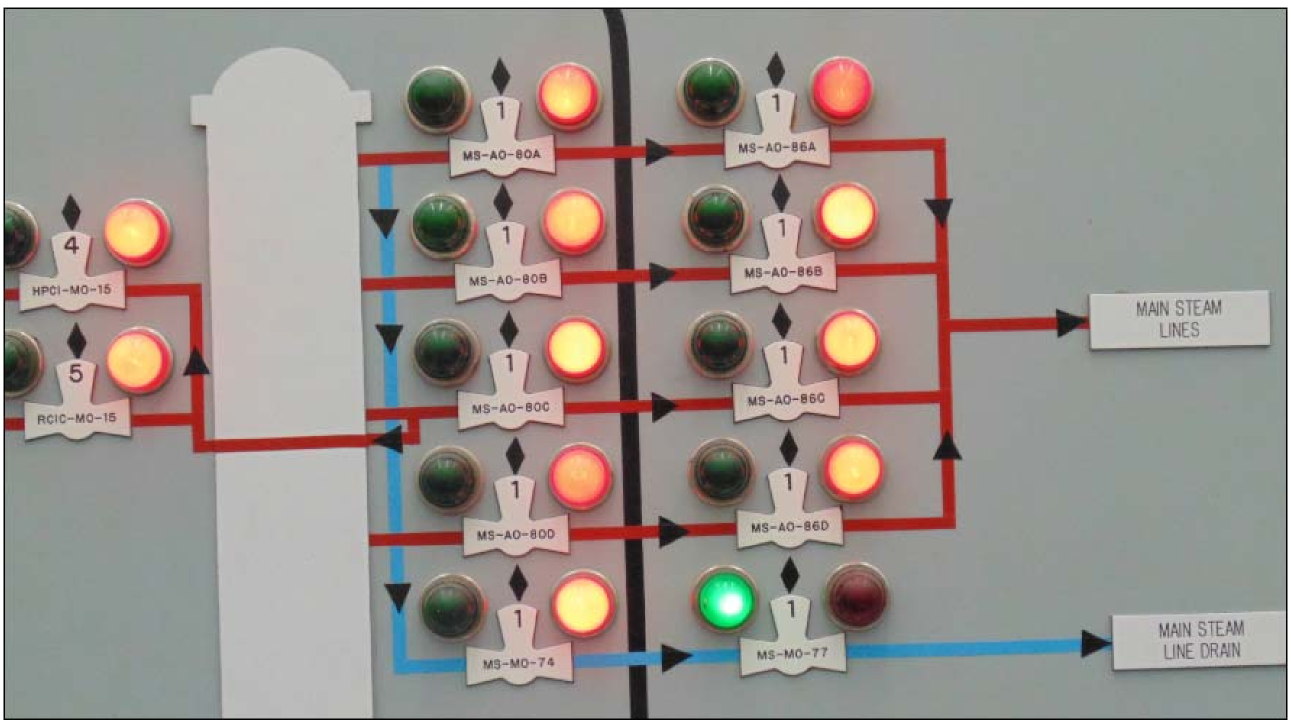
OF1 Closely monitoring instruments depends on knowing which instruments are available in the condition faced.

EO A.5 TS 3.6.1.3 deals with isolating PC penetrations with inoperable valves. — 4. Discuss the ADMINISTRATIVE CONTROL OF PRIMARY CONTAINMENT ISOLATION VALVES PER NOTE 1 TO LCO 3.6.1.3. section of this procedure.

a. Isol valves closed to satisfy TS 3.6.1.3 may be reopened intermittently if:

1. operator stationed at valve–s controls while it is open


OUTBD STM SUPP
ISOL VLV MO 16
AA3
OPEN


MS-AO-80A
MS-AO-86A
HPCI-MO-15
MS-AO-80B
MS-AO-86B
MAIN STEAM
LINES
RCIC-MO-15
MS-AO-80C
MS-AO-86C
MS-AO-80D
MS-AO-86D
MS-MO-74
MS-MO-77
MAIN STEAM
LINE DRAIN


Honeywell
Minitrend V5
BOTTOM OF MS LINES
112" IZ
INCHES
REACTOR FUEL ZONE & WIDE RANGE LEVEL RECORDER
NBI-LR-1A
CCP-1A
STEAM NOZZLE LVL
75
26
MAINMENU
SCREEN
MESSAGES
HELP
ENTER

PAM Instrumentation
3.3.3.1

Table 3.3.3.1-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

FUNCTION	REQUIRED CHANNELS	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1
1. Reactor Pressure	2	E
2. Reactor Vessel Water Level		
a. Fuel Zone	2	E
b. Wide Range	2	E
c. Steam Nozzle	1	F
3. Suppression Pool Level (Wide Range)	2	E
4. Primary Containment Gross Radiation Monitors	2	F
5. PCIV Position	2 per penetration flow path(a)(b)	E
6. Primary Containment H_2 & O_2 Analyzer	2	E
7. Primary Containment Pressure		
a. Drywell Narrow Range	2	E
b. Drywell Wide Range	2	E
c. Suppression Chamber Wide Range	2	E
8. Suppression Pool Water Temperature	2(c)	E

(a) Not required for isolation valves whose associated penetration flow path is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.

(b) Only one position indication channel is required for penetration flow paths with only one installed control room indication channel.

(c) A channel requires a minimum of four resistance temperature detectors (RTDs) to be OPERABLE with no two adjacent RTDs inoperable.

Examination Outline Cross-Reference	Level	RO
2.3.5 Ability to use radiation monitoring systems, such as fixed radiation monitors and alarms, portable survey instruments, personnel monitoring equipment, etc.	Tier#	3
	Group#	
	K/A #	G2.3.5
	Rating	2.9
	Revision	0
Revision Statement:		

Question 71

What is/are the **MINIMUM** personnel monitoring requirement(s) for exiting a contaminated area in the Reactor Building and dressing in street clothing IAW 9.EN-RP-100 (Radiation Worker Expectations)?

A. Perform a whole body frisk with a frisker ONLY.

B. Perform a hand and foot frisk with a frisker ONLY.

C. Perform a whole body frisk with a frisker **then** a whole body contamination monitor scan using a PCM.

D. Perform a hand and foot frisk with a frisker **then** a whole body contamination monitor scan using a PCM.

Answer: D

Explanation:
When exiting a contaminated area within the Reactor Building, personnel are required as a minimum to perform a hand and foot frisk (with a frisker) as soon as practical upon exiting the CA (RB airlock has friskers to support as soon as practical) and then proceed to a PCM for whole body contamination monitoring. Clothing can then be changed within the RCA. If Exiting the RCA personnel are required monitor themselves for contamination with a whole body contamination monitor and a gamma portal monitor. The examinee should recognize that contamination control requires a minimum of a hand and foot frisk to reduce the potential for spread of contamination. The requirement to exit the RCA via a whole body monitor is always a requirement.

Distracters:
Answer A is incorrect because it does not include hand and foot frisk or PCM. An examinee could choose this distractor if they do not equate Minimum as hand and foot frisk with contamination control. This answer is plausible because performing a whole body frisk would meet the hand and foot requirement.

Answer B is incorrect because it does not include the whole body monitor. An examinee could choose this distractor if they do not equate the whole body monitor with contamination control. This answer is plausible because performing hand and foot frisk is required.

Answer C is incorrect because it does not properly show the allowance for a hand and foot frisk. An examinee could choose this distractor if they did not remember the minimum requirement of the procedure. This answer is plausible because using the whole body monitor is required.

Technical References: Procedure 9.EN-RP-100 [Radiation Worker Expectations](Rev 15)

References to be provided to applicants during exam: none

Learning Objective: N/A

Question Source:	Bank #	4/2015 ILT NRC Q#72
(note changes; attach parent)	Modified Bank #	
	New	
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(11)	
Level of Difficulty:	2	
SRO Only Justification:	N/A	

PSA Applicability:
N/A

7.9 Remove all protective clothing prior to exiting a contaminated area.

<u>NOTE</u> – If multiple entries into contamination/high contamination areas are required, personnel should perform a frisk as soon as possible upon exiting each CA/HCA and once work/task complete, then proceed to a PCM for whole body contamination monitoring.

7.9.1 Personnel exiting a contamination area shall perform, as a minimum, a hand and foot frisk as soon as practical upon exiting, then proceed to a PCM for whole body contamination monitoring.

7.9.2 When exiting a highly contaminated area or a discrete radioactive particle area, a whole body frisk is done as soon as possible upon exiting, then proceed to a PCM for whole body contamination monitoring.

7.10 Perform a whole body frisk using a whole body contamination monitor (PCM) or a frisker before personnel don any clothing not worn in a contaminated area.

8. RADIOLOGICAL WORK PERMIT (RWP)

8.1 Compliance with a RWP is a legal requirement. Failure to comply could result in a NRC violation.

8.1.1 Obey verbal instructions which RP personnel provide during RWP briefing and during work.

8.1.2 Perform all work in a manner which causes your exposure to radiation and radioactive material to be As Low As Reasonably Achievable (ALARA).

8.2 Each Supervisor of work performed under a RWP is responsible for following:

8.2.1 Ensure work performed per RWP.

8.2.2 Coordinate with RP to ensure work area properly set up (e.g., with trash and clothing containers, and step-off pads) before work begins and that required radiological conditions are established by decontamination, shielding, contamination containment devices, etc.

8.2.3 Ensure work area kept orderly during work to prevent spread of contamination and is cleaned up after work.

8.2.4 Ensure work is done so workers' exposure to radiation and radioactive material is minimized.

8.2.5 Balance exposure among workers who perform similar jobs.

8.2.6 Periodically review dose distribution for individuals they supervise.

8.2.7 Ensure workers are aware of radiological conditions in work area and understand and comply with RWP requirements.

Examination Outline Cross-Reference	Level	RO
2.2.14 Knowledge of the process for controlling equipment configuration or status.	Tier#	3
	Group#	
	K/A #	G2.2.14
	Rating	3.9
	Revision	0
Revision Statement:		

Question 72 From previous 2 NRC Exams 3/2017 ILT NRC Q#70

A pipe cap painted yellow is installed directly downstream of a manual valve that has a single strand of wire with a lead seal attached.

What does this configuration represent?

A. Contaminated system

B. ECCS system high point vent

C. Operations test gauge connection

D. Primary Containment isolation boundary

Answer: D
Explanation: Procedure 2.0.1 section 14 contains the requirements for PC manual isolation valve and cap administrative control. It states numerous primary containment manual isolation valves and associated caps throughout plant are administratively controlled for strict control over their manipulation. Valves are identified by a tag labeled PRIMARY CONTAINMENT BOUNDARY and caps are identified by being painted yellow. A single strand of wire with a single lead seal is used for certain sealed closed primary containment manual isolation valves. These are installed in such a manner as to prevent valve operation without destroying seal.
Distracters: Answer A is plausible because yellow material is used to identify catch containments for radioactively contaminated water from system leaks. It is wrong because the configuration described in the stem is unique to control of PC manual isolation valves and pipe caps.

Answer B is plausible because some PC manual isolation valves are ECCS system vent valves. It is wrong because not all ECCS system manual valves are PC manual isolation valves, and the configuration described in the stem is specifically established to control of PC manual isolation valves and pipe caps.

Answer C is plausible because some PC manual isolation valves are system test gauge connection points. It is wrong because not all system test connection points are PC manual isolation valves, and the configuration described in the stem is specifically established to control of PC manual isolation valves and pipe caps.

Technical References: Procedure 2.0.1 [Plant Operations Policy] section 14 (Rev. 66), Procedure 2.0.2 [Operations Logs and Reports] (Rev. 118), Procedure 9.EN-RP-108 [Radiation Protection Posting] (Rev. 16)

References to be provided to applicants during exam: none

Learning Objective: INT032-01-03 EO-A1p, Discuss the following as described in Conduct of Operations Procedure 2.0.1, Plant Operations Policy: PC manual isolation valve and cap administrative control

Question Source:	Bank # **From previous 2 NRC Exams**	3/2017 ILT NRC Q#70
(note changes; attach parent)	Modified Bank #	
	New	
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(10)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	
PSA applicability:		
Top 10 Risk Significant Systems – Primary Containment (Isolation)		

3/2017 ILT NRC exam Q#70

Question 70

A pipe cap painted yellow is installed directly downstream of a manual valve that has a single strand of wire with a lead seal attached.

What does this configuration represent?

A. Contaminated system

B. ECCS system high point vent

C. Operations test gauge connection

D. Primary Containment isolation boundary

Answer: D. Primary Containment isolation boundary

14. PC MANUAL ISOLATION VALVE AND CAP ADMINISTRATIVE CONTROL Ⓟ[1]

14.1 Numerous primary containment manual isolation valves and associated caps throughout plant are administratively controlled for strict control over their manipulation.

14.1.1 Valves are identified by a tag labeled PRIMARY CONTAINMENT BOUNDARY and caps are identified by being painted yellow.

14.1.2 A single strand of wire with a single lead seal is used for certain sealed closed primary containment manual isolation valves. These are installed in such a manner as to prevent valve operation without destroying seal.

14.1.3 These valves are listed, controlled, and documented in Procedure 2.0.2.

15. ACCESS TO PLANT CABINETS/CONTROL OF SENSITIVE EQUIPMENT DOORS AND COVERS Ⓟ[2,5]

NOTE 1 – Plant cabinets is a generic term that encompasses many different types of components. Included in this definition, but not limited to, are the following: relay enclosures, MCC buckets, DC starters, lighting panels, control panels, electrical enclosures, etc.

NOTE 2 – With respect to this procedure, term "sensitive" relates to any active component that could cause a reactor protection trip, ESF actuation, or significant plant transient.

15.1 Permission to enter into plant cabinets to access components required by a procedure is considered given with following conditions:

15.1.1 If there are seismic sensitive relay(s) mounted on the door or cover, or if you are unsure, then contact Control Room to have operability of those relay(s) assessed prior to opening the door or cover.

ATTACHMENT 5 PC MANUAL ISOLATION VALVES AND CAP VERIFICATION

ATTACHMENT 5 PC MANUAL ISOLATION VALVES AND CAP VERIFICATION

Date/Time Started: ______________

Date/Time Completed: ______________

VALVE NUMBER	DESCRIPTION	LOCATION	CAP/PLUG INSTALLED (INITIALS)
PC-333	PC-PT-30A TEST CONN	R-903-NE ON AIRLOCK WALL NEAR MCC-K	
PC-113	PT-20 CALIBRATION	R-903-NE	
PC-115	PI-20 SHUTOFF	R-903-NE	
CS-54	CS PUMP A TEST LINE VENT	R-881-NE QUAD	
PC-243	DPT-3A-1 LOW SIDE DRAIN	R-859-NE QUAD	
PC-371	DPT-3A1 CALIBRATION VALVE	R-859-NE QUAD (25-1)	
PC-244	DPT-3A-1 LOW SIDE REMOTE DIAPHRAGM TEST CONNECTION	R-859-NE QUAD	
PC-260	DPT-3A1 EQUALIZER LINE DRAIN	R-859-NE QUAD	
PC-241	DPT-3A1 HIGH TEST CONN	R-859-NE QUAD	
PC-375	PT-2A1 CALIBRATION VALVE	R-859-NE QUAD (25-1)	
PC-247	DRAIN FOR PC-PT-2A1 AND LINE	R-859-NE QUAD	
RCIC-38	RCIC TURBINE EXHAUST TEST CONN ROOT	R-859-NE QUAD	N/A
RCIC-39	RCIC TURBINE EXHAUST TEST CONN SHUTOFF	R-859-NE QUAD	N/A
PC-221	DPT-20 LOW SIDE DRAIN	R-903-NW (25-51) ON WALL BEHIND RACK	
PC-595	PC-DPT-20 LOW SIDE CALIBRATION	R-903-NW (25-51)	
PC-596	PC-DPT-20 HIGH SIDE CALIBRATION	R-903-NW (25-51)	
PC-222	DPT-20 HIGH SIDE DRAIN	R-903-NW (25-51) ON WALL BEHIND RACK	
PC-223	PI-513 & PT-513 INSTRUMENT LINE DRAIN	R-903-NW (LR 104)	

4.7 Use yellow material for catch containments to identify the contained leakage as contaminated.

4.7.1 Ensure catch containment and drain tubing is conspicuously labeled for containing contamination if containment is located in a non-contaminated area.

4.8 Use labels stating "Possible Internal Contamination - Contact RP Prior to Opening" on equipment access locations (e.g., ventilation components) that are opened only during maintenance and internal surfaces may contain small or unknown amounts of contamination.

4.9 Post hot spots at a localized source of radiation where contact dose rates are > 100 mrem/hr and > 5 times dose rate at 30 cm per Procedure 9.EN-RP-109.

Examination Outline Cross-Reference	Level	RO
2.2.43 Knowledge of the process used to track inoperable alarms.	Tier#	3
	Group#	
	K/A #	G2.2.43
	Rating	3.0
	Revision	0
Revision Statement:		

Question 73

A Disabled Annunciator Record has been approved for disabling a Control Room alarm point.

(1) Who is responsible for performing the physical actions necessary to disable the alarm point?

AND

(2) What color self-adhesive flag placed on the affected annunciator window is used by the RO to track that the affected annunciator is disabled?

A. (1) SRO
(2) Pink

B. (1) SRO
(2) Green

C. (1) RO
(2) Pink

D. (1) RO
(2) Green

Answer: B

Explanation:
Procedure 2.3.1 governs the tracking process for disabled alarms. With respect to the process for tracking disabled Control Room annunciators, SROs are responsible for physically disabling and restoring the annunciator alarm point from the CRS display VID IAW procedure 2.2.64. After the point is disabled, ROs are responsible for placing green tape on the affected annunciator window and for removing the tape when the annunciator is returned to service.

Distracters:
Answer A part 1 correct. Part 2 is plausible because pink (color used in practice) self-adhesive flags are placed on annunciator windows to track the alarm is expected to be received as part of a pre-planned evolution. It is wrong because green flags are reserved for use to track disabled alarms.

Answer C part 1 is plausible because ROs do have responsibilities with respect to disabling and restoring inoperable annunciators and operators disable annunciators on local panels. It is wrong because the CRS performs the steps to disable the alarm points in RTP. Part 2 is plausible for the same reason stated for distractor A.

Answer C part 1 is plausible for the same reason stated for distractor A. Part 2 is correct.

Technical References: Procedure 2.3.1 [General Alarm Procedure](Rev 69), Procedure 2.2.64 [Annunciator System](Rev 20), Operator Desk Guide #3 [LCO Action Tracking System – NOMS](Rev 11)

References to be provided to applicants during exam: none

Learning Objective: INT032-01-03 EO-E1d, Discuss the following as described in Alarm Procedure 2.3.1, General Alarm Procedure: Annunciator disabling

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(10)	
Level of Difficulty:	2	
SRO Only Justification:	N/A	

PSA Applicability:
N/A

7.4.1 ENABLING/DISABLING POINTS

7.4.1.1 **DISABLE** a point as follows:

a. **SELECT** COMMAND.

b. **SELECT** POINT ENABLE.

c. **TYPE** POINT ID to be disabled or **SELECT** from drop down list box.

d. **SELECT** desired disabled status (DISABLE - NORMAL or DISABLE - ALARM) for both Train A and Train B.

e. **SELECT** APPLY.

f. At applicable VID, **VERIFY** point disabled.

7.4.1.2 **ENABLE** a point as follows:

a. **SELECT** COMMAND.

b. **SELECT** POINT ENABLE.

c. **TYPE** POINT ID to be enabled or **SELECT** it from drop down list box.

d. **SELECT** ENABLE for both Train A and Train B.

e. **SELECT** APPLY.

f. At applicable VID, **VERIFY** point enabled.

7. ANNUNCIATOR DISABLING OR PLACING IN POINT MAINTENANCE MODE©[1]

NOTE – Use of Master Silence feature does not require performance of this section or Attachment 1.

7.1 Disabling annunciators using this section applies only to the following:

7.1.1 Pulling alarm cards for non-Control Room alarms and Control Room Fire Panel alarms.

7.1.2 Disabling Control Room main panel alarms per Procedure 2.2.64.

7.1.3 Placing Control Room main panels alarm in Point Maintenance mode using Procedure 2.2.64.

7.2 Disabling annunciators by methods other than pulling alarm cards or disabling Control Room main panels alarms shall be evaluated and controlled per appropriate Engineering or Work Control processes.

7.3 Annunciators may be intentionally disabled or placed in Point Maintenance mode only for following:

7.3.1 Malfunctioning/failed, preventing "dark board".

7.3.2 Alarming due to related component malfunctioning/failed.

7.3.3 Alarming due to related component out of service.

7.3.4 Alarming due to maintenance activity.

7.11 After alarm evaluation has been approved and any compensatory measures established, or when directed by procedure or work document, perform following:

7.11.1 Ensure green self-adhesive flag is placed on affected annunciator window.

7.11.2 If desired, remove annunciator by:

7.11.2.1 Place in Point Maintenance mode or disable Control Room main panel per Procedure 2.2.64.

PROCEDURE 2.3.1 REVISION 69 PAGE 12 OF 30

7.11.2.2 Pull applicable annunciator card for non-Control Room alarms or Control Room Fire Panel alarms.

7.12 When annunciator/related component is repaired, conditions change to stop nuisance cycling or continuous annunciation, or when directed by procedure or work document, perform following:

7.12.1 Ensure green self-adhesive flag removed from affected annunciator window.

7.12.2 If required, restore alarm to service by:

7.12.2.1 Enable annunciator point per Procedure 2.2.64.

7.12.2.2 Insert applicable annunciator card for non-Control Room alarms or Control Room Fire Panel alarms.

7.12.3 Close Disabled Point Tracking record in NOMS per Operations Desk Guide 3, if used.

7.12.4 Discard APE if alarm point is restored prior to NOMS becoming available.

7.12.5 Close narrative log entry if used.

4.11 Expected alarms, such as those associated with a Surveillance Procedure or other maintenance activities, or as determined by the CRS, may be identified with a "flag" to signify an expected alarm. This will be communicated to the CRS prior to receiving the alarm. Once "flagged" as an expected alarm for a SP or maintenance activity, the communication of each time the alarm comes in and resets is not required as long as the alarm is received at the appropriate time or is caused by identified maintenance activity. If the "flagged" annunciator were to come in at a time not specified in the procedure or alarm was not caused by identified maintenance activity, it is to be treated as an unexpected annunciator.

4.12 During a plant transient, multiple annunciators may be coming in rapidly. The panel Operator will acknowledge the annunciators as soon as reasonably possible, commensurate with the importance of the activities that are on-going. It is not necessary to announce all annunciators that come in during a transient, but operationally significant events that are indicated by annunciators should be announced. Announcements that are made shall be prioritized according to their relative merit to other communications that are on-going.

4.13 Annunciator steps should be performed in sequence unless mitigating circumstances warrant altering the sequence. To support priorities during event mitigation, its acceptable to perform steps out-of-sequence. The procedures may not address all possible plant conditions and therefore, some steps may not apply. If steps are performed out-of-sequence or not performed, the user and CRS or SM shall ensure all applicable steps are performed and procedure intent is not altered. If steps are not performed, justification for non-performance shall be documented/logged. If necessary, an IDOCS request should be entered to evaluate the adequacy of the procedure guidance.

4.14 When an alarm is energized, audio will activate and appropriate window will flash. After determining which annunciator is alarming, press ACKNOWLEDGE button to silence alarm.

4.15 Announce alarm in a timely manner. Back panel alarms may be announced as read from the VID or the Master Alarm Log prior to responding around back or once the Operator has returned from the back panels. Unexpected alarms should be announced by reading or paraphrasing the annunciator descriptor. Expected alarms may be announced as such.

Examination Outline Cross-Reference	Level	RO
2.1.20 Ability to interpret and execute procedure steps.	Tier#	3
	Group#	
	K/A #	G2.1.20
	Rating	4.6
	Revision	1
Revision Statement: Rev 1 – Ops Rep review identified per 2.0.1.2 note before step 2.1 states 0-EN-HU-106 is NOT applicable to AOPs. Revised stem to remove reference to 0-EN-HU-106 and revised answer B to now be the correct answer. Based on validators' comments, condensed stem by removing reference to manual scram and added "unconditional" step to make more generic.		

Question 74

IAW Procedure 2.0.1.2 [Operations Procedure Policy],

Which one of the following listed actions meets the MINIMUM requirements for marking an unconditional step as N/A in an abnormal or emergency procedure?

Mark the step N/A AND…

A. annotate a reason for not performing the step AND initial and date the step, ONLY.

B. obtain concurrence from the CRS that procedure intent is NOT altered by skipping the step, ONLY.

C. obtain concurrence from the SM that procedure intent is NOT altered by skipping the step, AND document the reason for not performing the step, AND both initial and date the step.

D. obtain concurrence from the AOM Shift that procedure intent is NOT altered by skipping the step, AND document the reason for not performing the step, AND both initial and date the step.

Answer: B
Explanation: This questions tests knowledge of the note before step 2.1 of procedure 2.0.1.2 that exempts Abnormal Procedures from the requirements of procedure 0-EN-HU-106 and tests ability to interpret Procedure 2.0.1.2 step 6.1.7, exceptions to continuous use procedures. For procedures other than AOPs, EPs, EOPs, and Alarm Cards, procedure 0-EN-HU-106 requirements would apply. 0-EN-HU-106 step 5.2.3[1] states what constitutes a

conditional step when executing abnormal procedure actions. Per Procedure 2.0.1.2, AP and EP steps should be performed in sequence unless mitigating circumstances warrant altering the sequence. To support priorities during event mitigation, it's acceptable to perform steps out of sequence. The procedures are typically written given the plant is at 100% power. Therefore, some actions in the procedure that are performed at power may not be applicable in other modes of operation (e.g., tripping the main turbine and scramming the reactor). The procedures may not address all possible plant conditions and therefore, some steps may not apply. If steps are performed out of sequence or not performed, the user and CRS or SM shall ensure all applicable steps are performed and procedure intent is not altered. If steps are not performed, justification for non-performance shall be documented/logged.

Procedure 0-EN-HU-106 states:

> **IF** conditions are discovered where Procedure or Work Instruction steps cannot or should not be performed, **THEN** the step may be marked "N/A" if ALL of the following criteria are satisfied:
>
> - The step is not needed or cannot be performed due to the current mode, condition, or configuration of the plant.
> - Marking the step N/A Does Not violate the Limits or Precautions or initial conditions described in the Procedure or Work Instruction.
> - Marking the step N/A Does Not create an unsafe condition in the Procedure or Work Instruction.
> - Marking the step N/A Does Not change the intent (method of operation or the results) of the steps or sections.
>
> **IF** all conditions listed in step [4] are met, **THEN** a justification for marking the step or section "N/A" shall be approved and annotated on the document as follows:
>
> - Two knowledgeable individuals shall agree with the steps or sections to be marked "N/A" of which one shall be a supervisor or above. Both individuals who agreed shall initial the steps marked N/A before the document is considered complete.

As described in the stem, the subject step to insert a manual scram is not a conditional step, and per the note at procedure 2.0.1.2, the requirements of procedure 0-EN-HU-106 do not apply. Therefore, the only action necessary to N/A the subject step is to obtain concurrence from the CRS or SM that procedure intent is not altered.

Distracters:

Answer A is plausible because 0-EN-HU-106 step 5.2.3[1] allows steps that contain conditional statements to be marked N/A without supervisory approval. The examinee who confuses the requirements for conditional steps with steps that are not conditional may choose this answer. It is wrong because IAW procedure 2.0.1.2, although most APs are written from the perspective of the plant being at 100% power, step 6.1.7 still requires concurrence from the CRS or SM in order to not perform a step. Also, since 0-EN-HU-106 is not applicable to AOPs, initialing and dating is not specifically required.

Answer C is plausible because it contains the requirement to have the CRS or SM concur intent is not altered, which is correct, and because this answer would be correct if 0-EN-HU-106 requirements applied. An examinee who does not know AOPs are exempted from 0-EN-HU-106 requirements may choose this answer. It is wrong because it goes above the minimum requirements as requested in the stem.

Answer D is plausible because it contains the to have the CRS or SM concur intent is not altered, and the 0-EN-HU-106 requirement to document the reason for marking the step N/A. It is also plausible because the AOM-Shift is responsible for the final Operations review of all completed AOPs, including review of steps not performed. It is wrong because procedure 2.0.1.2 states either the on shift CRS or SM must provide concurrence to not perform a step and because it goes above the minimum requirements as requested in the stem.

Technical References: Procedure 2.0.1.2 [Operations Procedure Policy](Rev 47), Procedure 0-EN-HU-106 [Procedure and Work Instruction Use and Adherence](Rev 3C2)

References to be provided to applicants during exam: none

Learning Objective: INT032-01-01 EO-R1a, Discuss the following as described in 2.0.1.2, Operations Procedure Policy: Operations Procedure Use; R1e, Abnormal and Emergency Procedures

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(10)	
Level of Difficulty:	3	
SRO Only Justification:	N/A	

PSA Applicability:

N/A

1. PURPOSE®[1]

1.1 Provide Operations procedure usage requirements and Operations Management's expectations.

1.2 These requirements are in addition to the requirements of Procedure 0-EN-HU-106.

2. OPERATIONS PROCEDURE USE - GENERAL®[6]

NOTE – Procedure 0-EN-HU-106 is not applicable to EOP, Emergency, Abnormal, and Alarm Procedures.

2.1 Refer to Procedure 0-EN-HU-106 for use and adherence requirements for procedures other than EOP, Emergency, Abnormal, and Alarm Procedures.

PROCEDURE 2.0.1.2 REVISION 47 PAGE 1 OF 15

6. ABNORMAL AND EMERGENCY PROCEDURES®[6]

6.1 ABNORMAL AND EMERGENCY PROCEDURE USAGE - GENERAL

6.1.1 APs and EPs shall be classified as Continuous Use. The exception to Continuous Use is when performing Immediate Operator Actions from memory as prescribed in Step 6.5.1.

6.1.2 In general, APs address less severe conditions than EPs. An exception to this is electrical casualty procedures that are grouped together as 5.3 series for improved human factoring.

6.1.3 APs and EPs use a numeric-alpha numbering scheme. The alpha is a casualty or system descriptor. All APs are 2.4 series. EPs numeric series is defined below.

6.1.3.1 5.1 series typically address whole plant or large area emergencies.

6.1.3.2 5.2 series typically address individual piping system emergencies.

PROCEDURE 2.0.1.2 REVISION 47 PAGE 3 OF 15

6.1.7 AP and EP steps should be performed in sequence unless mitigating circumstances warrant altering the sequence. To support priorities during event mitigation, it's acceptable to perform steps out of sequence. The procedures are typically written given the plant is at 100% power. Therefore, some actions in the procedure that are performed at power may not be applicable in other modes of operation (e.g., tripping the main turbine and scramming the reactor). The procedures may not address all possible plant conditions and therefore, some steps may not apply. If steps are performed out of sequence or not performed, the user and CRS or SM shall ensure all applicable steps are performed and procedure intent is not altered. If steps are not performed, justification for non-performance shall be documented/logged. If necessary, an IDOCS request should be entered to evaluate the adequacy of the procedure guidance.Ⓟ[5]

PROCEDURE 2.0.1.2 REVISION 47 PAGE 4 OF 15

	NUCLEAR MANAGEMENT MANUAL	QUALITY RELATED	0-EN-HU-106	REV. 3C2
		INFORMATION USE	PAGE 9 OF 23	
	Procedure and Work Instruction Use and Adherence			

5.2.3 Cont.

[3] Marking any portion of a document "N/A" shall be carefully considered. Steps in a document shall not be marked "N/A" simply because the steps are wrong or out of an individual's preferred sequence.

[4] **IF** conditions are discovered where Procedure or Work Instruction steps cannot or should not be performed, **THEN** the step may be marked "N/A" if ALL of the following criteria are satisfied:

(a) The step is not needed or cannot be performed due to the current mode, condition, or configuration of the plant.

(b) Marking the step N/A Does Not violate the Limits or Precautions or initial conditions described in the Procedure or Work Instruction.

(c) Marking the step N/A Does Not create an unsafe condition in the Procedure or Work Instruction.

(d) Marking the step N/A Does Not change the intent (method of operation or the results) of the steps or sections.

[5] **IF** all conditions listed in step [4] are met, **THEN** a justification for marking the step or section "N/A" shall be approved and annotated on the document as follows:

(a) Two knowledgeable individuals shall agree with the steps or sections to be marked "N/A" of which one shall be a supervisor or above. Both individuals who agreed shall initial the steps marked N/A before the document is considered complete.

(b) Supervisory permission to use "N/A" may be obtained during the pre-job briefing or via verbal concurrence at other times during the job evolution. The step or action shall be "N/A'd" prior to proceeding to the next step or action.

5.2.4 Annotate the reason for the "N/A" in the document. Place the annotation close to the step or in the comment section of the document.

5.2.5 Actions to Take When Editorial/Pen-and-Ink Changes are Identified While Procedure or Work Instruction is in Progress.

[1] If editorial/pen-and-ink changes (see Procedure 0.4 for procedures and 0-CNS-WM-105 for work instructions) are identified while using a Procedure or Work Instruction, work may continue provided the following actions are taken with concurrence of the supervisor:

(a) Line through the error and enter the correct information.

	NUCLEAR MANAGEMENT MANUAL	QUALITY RELATED	0-EN-HU-106	REV. 3C2
		INFORMATION USE	PAGE 8 OF 23	
Procedure and Work Instruction Use and Adherence				

5.2.2 Cont.

[3] Continuous Use and Reference Use procedure users shall perform the Procedure or Work Instruction steps in the sequence written unless specific allowance to skip sections/steps is permitted in the Procedure or Work Instruction. Steps identified as bulleted steps rather than numbered or lettered steps can be performed in any sequence or in parallel.

[4] In the event of an emergency situation not covered by a Procedure or Work Instruction, the personnel involved shall take action to minimize personnel injury and damage to the facility.

[5] Before performing a procedural step, the Procedure or Work Instruction user should ensure that:

(a) Action to be performed is on the correct component.

(b) Expected response has been anticipated.

(c) The appropriate monitoring method for the response has been identified.

[6] When indicating a step is complete:

(a) Perform placekeeping in accordance with this procedure (Sec 5.6.3).

(b) When work conditions prevent the performer from physically signing or initialing a step as it is performed (e.g., in a contaminated area), the step shall be signed off as soon as work conditions make signing possible. In no case shall this be later than the end of the shift in which the step was completed.

(c) If an incorrect entry is made to a Procedure or Work Instruction (i.e., data entry, initial, etc.), draw a single line through the entry and initial and date the line through. Locate the initial and date to minimize the likelihood that they are misconstrued as the intended data entry. Do not use White-Out, correction tape, or Liquid Paper type products to make corrections.

[7] If a Procedure or Work Instruction is stopped and cannot be resumed during the same shift (other than shift turnover), prior to restarting, ensure that all Prerequisites and any Initial Conditions necessary for performance are satisfied.

5.2.3 Use of Not Applicable (***N/A***) During Procedure or Work Instruction use:

[1] Procedure or Work Instruction steps that contain conditional statements or provide specific conditions for being marked as not applicable may be marked N/A without additional written justification or supervisory approval.

[2] If no steps of a Procedure section or Work Instruction section are performed, documentation of N/A of each step is not required.

6.1.8 When an AP or EP is entered, the marked-up procedure should be retained for routing purposes. First, the CRS and SM should review the marked up procedure prior to exiting. Second, the marked-up completed procedure should be forwarded to AOM-Shift for final review. Third, the reviewed and marked-up procedure is sent to OSG Supervisor for event report, if needed, and for identifying potential improvements. After review by OSG Supervisor, the procedure can be disposed of, if not needed for records. The first benefit of this is for accurate record of steps performed in carrying out the Abnormal/Emergency Procedure, especially if an event report is needed. Second benefit is for Shift Crew Management, AOM-Shift, and OSG Supervisor the opportunity to identify any potential improvements in the procedure. Lastly, it would provide the Shift Crew Management the chance to ensure restoration steps that may be in the Abnormal/Emergency Procedure are not missed.

6.1.9 Emergency Procedure 5.3ALT-STRATEGY contains guidance to operate the Williams fire pump. While this guidance is intended for emergency operations, it can also be used for Williams fire pump routine testing, maintenance runs, and training evolutions. The rules of usage for Emergency Procedures do not apply when Procedure 5.3ALT-STRATEGY is used for Williams fire pump routine testing, maintenance runs, and training evolutions; however, Procedure 0-EN-HU-106 shall be followed. Use of the Williams pump hard card is permitted during these evolutions; this is an exception to Section 4 requirements.

6.2 SCRAM ACTION

6.2.1 If scram actions are contained in an AP, EP, or Alarm Card, the first page of the procedure or alarm card will contain a "Scram Action" watermark along the right hand margin of the page. In addition, the word scram in the action step(s) will be capitalized and scram actions bolded. Ⓟ[4]

6.3 ENTRY AND EXIT CONDITIONS

6.3.1 This section is used to list plant conditions or indications that are indicative of expected abnormal operational conditions or transients.

6.3.2 APs and EPs shall be entered from any of following:

6.3.2.1 When directed by another plant procedure.

6.3.2.2 When abnormal or emergency plant conditions are consistent with Procedure Entry Conditions:

a. Entry conditions are formatted as a list. Generically, if any entry condition is met, the procedure should be entered unless the entry condition specifies entry based on a logic term (e.g., "and", "or", "if", "if not", and "when").

6.3.3 APs and EPs may be entered without a specific entry condition if guidance is useful in mitigating a degraded plant condition.

Examination Outline Cross-Reference	Level	RO
2.2.40 Ability to apply technical specifications for a system.	Tier#	3
	Group#	
	K/A #	G2.2.40
	Rating	3.4
	Revision	0
Revision Statement:		

Question 75

With the plant at power, a manual valve is closed in order to maintain Primary Containment OPERABLE IAW TS LCO 3.6.1.3 (PCIVs).

The valve is required to be opened per **CRS direction** with a NLO stationed at the valve.

Which of the following completes the statements below regarding the actions required to maintain Administrative Control of this PCIV while open IAW Procedure 2.0.1 [Plant Operations Policy]?

Direct the NLO to establish ____(1)____ communication with the Control Room and to close the valve in event of an accident condition.

The instructions provided to the NLO ____(2)____ required to be documented in the Control Room log.

A. (1) continuous
(2) are

B. (1) continuous
(2) are NOT

C. (1) intermittent
(2) are

D. (1) intermittent
(2) are NOT

Answer: A
Explanation: This question requires the Reactor Operator to coordinate personnel activities outside the control room (Plant Operator local valve operations under TS Administrative Controls).

Procedure 2.0.1 (Plant Operations Policy) provides the following guidance:
Isolation valves closed to satisfy LCO 3.6.1.3 may be re-opened on an intermittent basis following administrative controls:

- A person shall be stationed at valve controls while valve is open.
- If valve is being controlled outside of Control Room, person at valve controls shall be in continuous communication with Control Room.

Person at valve controls shall be instructed to close valve in event of an accident condition. These instructions shall be documented (the Control Room log satisfies this requirement).

This question is generic (Tier 3) in nature because administrative controls for PCIVs applies to components in a broad range of plant systems.

Distracters:
Answer B is incorrect due to NLO instructions being required to be logged. This choice is plausible due to logging the NLO instructions not being required if performed by a controlling document vs. CRS direction. The examinee that correctly identifies continuous communication and does not identify the CRS direction vs. controlling document would chose this answer.

Answer C is incorrect due to continuous communications being required. This choice is plausible because the word “intermittent” has familiar association with the subject requirement (i.e. valve may be opened on an intermittent basis) and because most communications between NLOs in the field and the Control Room being intermittent (head tank level, system parameters) during system operations and monitoring. The examinee that incorrectly identifies intermittent communication and correctly identifies the logging requirement would chose this answer.

Answer D is incorrect due to continuous communications being required and the NLO instructions being required to be logged. This choice is plausible due to most communications between NLOs in the field and the Control Room being intermittent during system operations and monitoring and logging the NLO instructions not being required if performed by a controlling document vs. CRS direction. The examinee that incorrectly identifies intermittent communication and does not identify the CRS direction vs. controlling document would chose this answer.

Technical References: TS Procedure 2.0.1 [Plant Operations Policy](Rev. 66)

References to be provided to applicants during exam: none

Learning Objective: SKL008-01-02 EO-4, Describe the administrative controls for primary or secondary containment manual valve opening or associated cap removal when primary or secondary containment is required.

Question Source:	Bank #	4/2015 ILT NRC Q#66
(note changes; attach parent)	Modified Bank #	

	New	
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.41(b)(10)	
Level of Difficulty:	2	
SRO Only Justification:	N/A	
PSA Applicability:		
Top 10 Risk Significant System – Primary Containment		

Question: 66

With the plant at power, a manual valve is closed in order to maintain Primary Containment OPERABLE IAW TS LCO 3.6.1.3 (PCIVs).

The valve is required to be opened per CRS direction with a NLO stationed at the valve.

Which of the following completes the statements below regarding the actions required to maintain Administrative Control of this PCIV while open IAW Procedure 2.0.1 (Plant Operations Policy)?

Direct the NLO to establish ____(1)_____ communication with the Control Room and to close the valve in event of an accident condition.
The instructions provided to the NLO ____(2)____ required to be documented in the Control Room log.

A. (1) continuous
(2) are

B. (1) continuous
(2) are NOT

C. (1) intermittent
(2) are

D. (1) intermittent
(2) are NOT

Answer:
A. (1) continuous
(2) are

PCIVs
3.6.1.3

3.6 CONTAINMENT SYSTEMS

3.6.1.3 Primary Containment Isolation Valves (PCIVs)

LCO 3.6.1.3 Each PCIV, except reactor building-to-suppression chamber vacuum breakers, shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
When associated instrumentation is required to be OPERABLE per LCO 3.3.6.1, "Primary Containment Isolation Instrumentation."

ACTIONS

------------------------------------NOTES------------------------------------

1. Penetration flow paths may be unisolated intermittently under administrative controls.

2. Separate Condition entry is allowed for each penetration flow path.

3. Enter applicable Conditions and Required Actions for systems made inoperable by PCIVs.

4. Enter applicable Conditions and Required Actions of LCO 3.6.1.1, "Primary Containment," when PCIV leakage results in exceeding overall containment leakage rate acceptance criteria.

----

4. ADMINISTRATIVE CONTROL OF PC ISOLATION VALVES PER NOTE 1 TO LCO 3.6.1.3

4.1 Isolation valves closed to satisfy LCO 3.6.1.3 may be re-opened on an intermittent basis under following administrative controls:

NOTE – "Valve controls" is location at which valve closure can be assured.

4.1.1 A person shall be stationed at valve controls while valve is open.

4.1.2 If valve is being controlled outside of Control Room, person at valve controls shall be in continuous communication with Control Room.

PROCEDURE 2.0.1 REVISION 66 PAGE 2 OF 13

NOTE – If document that controls opening valve has a step (usually in limitation section) which directs closing valve when required by Control Room Operator, documentation requirements of Step 4.1.3 are satisfied.

4.1.3 Person at valve controls shall be instructed to close valve in event of an accident condition. These instructions shall be documented (e.g., in a procedure, special instructions, SM Log, etc.). An example of a log entry, when document controlling opening valve does not contain any guidance, would be as follows:

1044 - INSTRUCTED PERSON AT PC-AO-237 CONTROLS TO CLOSE VALVE IN THE EVENT OF AN ACCIDENT.

4.1.4 Whenever valve is opened by a document without verification points, following logging criteria and Independent Verifications are required:

4.1.4.1 When valve is opened, opening of valve shall be logged in Control Room Log.

Example - 1045 OPENED PC-AO-237.

Examination Outline Cross-Reference	Level	SRO
259002 (SF2 RWLCS) Reactor Water Level Control 2.4.30 Knowledge of events related to system operation/status that must be reported to internal organizations or external agencies, such as the State, the NRC, or the transmission system operator.	Tier#	2
	Group#	1
	K/A #	295002 G2.4.30
	Rating	4.1
	Revision	0
Revision Statement:		

Question 76

The plant is at 100%.

The following events have occurred:

Time	Event
1800	NOUE **declared** due to loss of annunciators per EAL SU4.1
1810	Reactor scram due to Master Level Controller failure (EAL SA4.1 met)
1815	**FIRST** communication made to NRC for above events
1820	ALERT **declaration** made for EAL SA4.1 by the On-Shift Emergency Director
1925	**SECOND** communication made to NRC for above events

(1) Which procedure(s) related to NRC reporting requirements is/are required to be entered for this event?

AND

(2) Was the NRC informed for ALL events within the time requirements of plant procedures?

A. (1) 5.7.6 [Notification] AND 2.0.5 [Reports to the NRC Operations Center]
(2) Yes

B. (1) 5.7.6 [Notification] AND 2.0.5 [Reports to the NRC Operations Center]
(2) No

C. (1) 5.7.6 [Notification], ONLY
(2) Yes

D. (1) 5.7.6 [Notification], ONLY
(2) No

Answer: B		
Explanation: The event describes involves a significant plant transient due to failure of the reactor water level control system that requires upgrade to the emergency classification. Reports associated with E-Plan entry are categorized as emergency events. Procedure 5.7.6 governs reporting to outside agencies (state, local, NRC) for emergency events. Procedure 2.0.5 governs non-emergency reports to the NRC. Failure of the Master Level Controller resulted in a scram. Combined with loss of annunciators, this required a new emergency classification, upgrade to Alert. The NRC is required to be informed using the ENS as soon as possible after notification of state and local agencies but in all cases within 1 hour of event declaration. Notification of the upgrade to Alert was due within 1 hour of 1820, by 1920. Notification to the NRC was at 1925, so it did not meet procedural requirements.		
Distracters: Answer A part 1 is correct. Part 2 is plausible because the first report to the NRC for the NOUE was within the time limit of 1 hour.. The examinee who does not know the NRC must be informed of the upgrade to Alert may choose this answer. It is wrong because notification to the NRC for the Alert was due no later than 1920. Answer C part 1 is plausible because is plausible because the specific directions for emergency reports are contained in procedure 5.7.6. It is wrong because procedure 2.0.5 states plant conditions which require declaration of an emergency classification and notification per Procedure 5.7.6 also require performance of this procedure to ensure non-emergency reports continue to be made as required. Part 2 is plausible and wrong for the same reason as given for distractor A. Answer D part 1 is plausible and wrong for the same reasons stated for distractor C. Part 2 is correct.		
Technical References: Procedure 2.0.5 [Reports to the NRC Operations Center](Rev 50), Procedure 5.7.6 [Notification](Rev 75), Procedure 5.7.1 [Emergency Classification] Att. 4 [EPIPEALHOT](Rev 18)		
References to be provided to applicants during exam: none		
Learning Objective: INT032-01-03 EO-F1a, Procedure 2.0.5, Reports to NRC Operations Center: Discuss the following as described in Procedure 2.0.5, Reports to NRC Operations Center: Purpose of procedure along with the differences between Immediate Emergency and Non-Emergency notifications		
Question Source:	Bank #	

(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.43(b)(5)	
Level of Difficulty:	3	
SRO Only Justification:		
This question requires assessment of plant conditions, selection of the appropriate administrative procedure governing reporting requirements, and knowledge of information contained within attachments in the applicable administrative procedure.		
PSA Applicability:		
N/A		

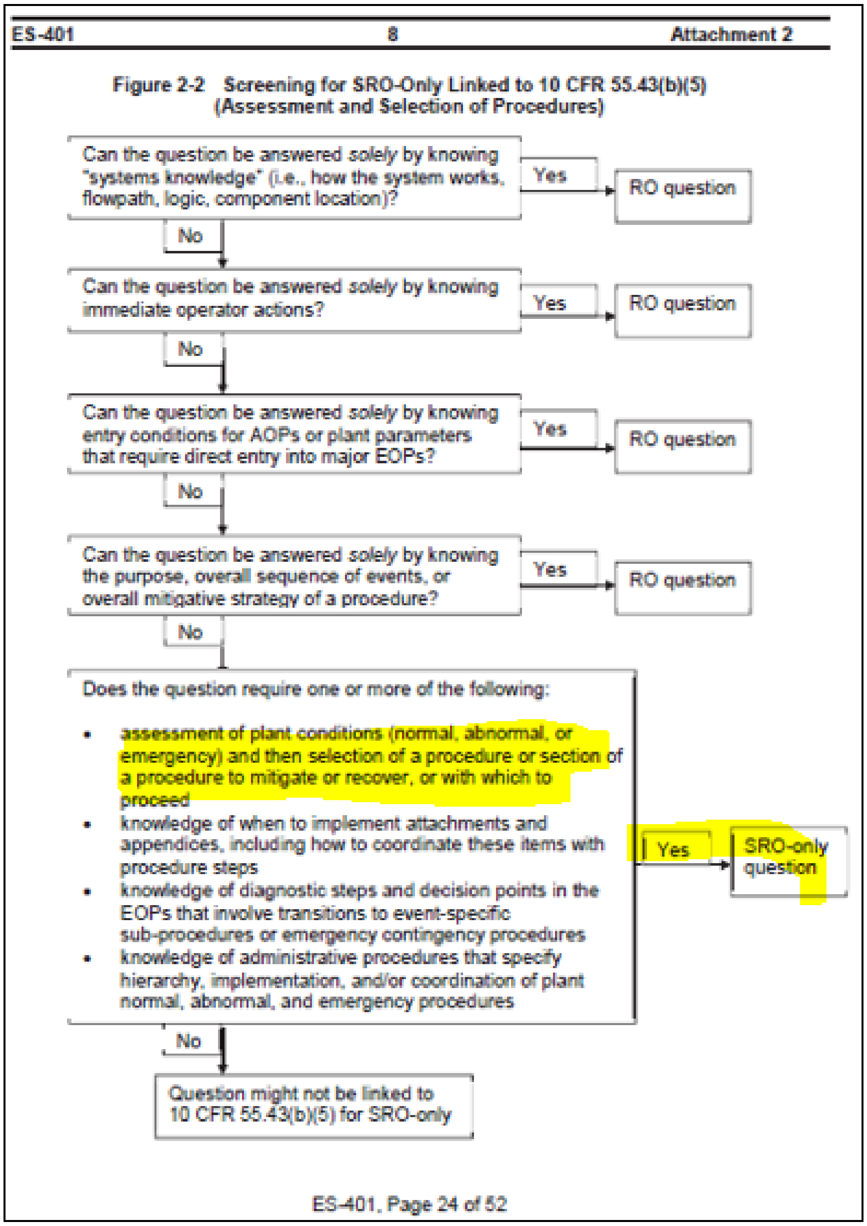


Figure 2-2 Screening for SRO-Only Linked to 10 CFR 55.43(b)(5) (Assessment and Selection of Procedures)

Can the question be answered *solely* by knowing "systems knowledge" (i.e., how the system works, flowpath, logic, component location)? — Yes → RO question

No

Can the question be answered *solely* by knowing immediate operator actions? — Yes → RO question

No

Can the question be answered *solely* by knowing entry conditions for AOPs or plant parameters that require direct entry into major EOPs? — Yes → RO question

No

Can the question be answered *solely* by knowing the purpose, overall sequence of events, or overall mitigative strategy of a procedure? — Yes → RO question

No

Does the question require one or more of the following:

- assessment of plant conditions (normal, abnormal, or emergency) and then selection of a procedure or section of a procedure to mitigate or recover, or with which to proceed
- knowledge of when to implement attachments and appendices, including how to coordinate these items with procedure steps
- knowledge of diagnostic steps and decision points in the EOPs that involve transitions to event-specific sub-procedures or emergency contingency procedures
- knowledge of administrative procedures that specify hierarchy, implementation, and/or coordination of plant normal, abnormal, and emergency procedures

Yes → SRO-only question

No

Question might not be linked to 10 CFR 55.43(b)(5) for SRO-only

C. Facility Licensee Procedures Required To Obtain Authority for Design and Operating Changes in the Facility [10 CFR 55.43(b)(3)]

Some examples of SRO exam items for this topic include the following:

- screening and evaluation processes under 10 CFR 50.59, "Changes, Tests and Experiments"
- administrative processes for temporary modifications
- administrative processes for disabling annunciators
- administrative processes for the installation of temporary instrumentation
- processes for changing the plant or plant procedures

Section IV provides an example of a satisfactory SRO-only question related to this topic.

D. Radiation Hazards That May Arise during Normal and Abnormal Situations, including Maintenance Activities and Various Contamination Conditions [10 CFR 55.43(b)(4)]

Some examples of SRO exam items for this topic include the following:

- process for gaseous/liquid release approvals (i.e., release permits)
- analysis and interpretation of radiation and activity readings as they pertain to the selection of administrative, normal, abnormal, and emergency procedures
- analysis and interpretation of coolant activity, including comparison to emergency plan criteria and/or regulatory limits

SRO-only knowledge should not be claimed for questions that can be answered *solely* based on RO knowledge of radiological safety principles (e.g., radiation work permit requirements, stay time, and DAC hours).

E. Assessment of Facility Conditions and Selection of Appropriate Procedures during Normal, Abnormal, and Emergency Situations [10 CFR 55.43(b)(5)]

This 10 CFR 55.43 topic involves both (1) assessing plant conditions (normal, abnormal, or emergency) and then (2) selecting a procedure or section of a procedure to mitigate or recover, or with which to proceed. One area of SRO-level knowledge (with respect to selecting a procedure) is knowledge of the content of the procedure versus knowledge of the procedure's overall mitigative strategy or purpose.

SA4.1 1 2 3	SU4.1 1 2 3
Unplanned loss of > approximately 75% of annunciators or indicators associated with safety systems on Control Room Panels 9-3, 9-4, 9-5, and C for ≥ 15 min. (Note 3) **AND EITHER:** Any significant transient is in progress, Table S-1 **OR** Compensatory indications are unavailable	Unplanned loss of > approximately 75% of annunciators or indicators associated with safety systems on Control Room Panels 9-3, 9-4, 9-5, and C for ≥ 15 min. (Note 3)

Table S-1 Significant Transients
Reactor scram
Runback > 25% thermal power
Electrical load rejection > 25% full electrical load
ECCS injection
Thermal power oscillations > 10%

1. PURPOSE

1.1 The purpose of this procedure is to establish immediate notification requirements and 60 day telephone reporting requirements for reports to the NRC Operations Center for non-emergencies. Immediate notification requirements for emergencies are included in Procedure 5.7.6. Immediate notifications for non-emergencies are categorized into immediate, 1 hour, 4 hour, 8 hour, or 24 hour and 30 day reports. Guidance is provided in this procedure on determining the appropriate reporting category, confirming the accuracy of reported information, performing the required notification, and providing subsequent updates or retracting the report based on evaluations of additional data. Additional guidance for determining reportability can be found in NUREG 1022, Revision 3, Generic Letter 91-03, or references contained in Section 6. This procedure covers immediate notifications performed by Operations or Security, and 30 and 60 day telephone reports performed by Licensing.

2. DISCUSSION

2.1 Plant conditions which require declaration of an emergency classification and notification per Procedure 5.7.6 also require performance of this procedure to ensure non-emergency reports continue to be made as required. Control Room Staff continue to identify non-emergency reportable events, but may direct the Emergency Notification System (ENS) Communicator in the Technical Support Center (TSC) to make the actual phone call and log the notification. During declared emergencies, completion of Attachments 8 and 9 are not required.

2.2 Most conditions reported to the NRC per this procedure will require a 30 day written report or 60 day follow-up LER per Procedure 0-CNS-LI-108. Preparation of the report or LER is the responsibility of the Licensing Department. The determination of 30 or 60 day reportability will be made as part of processing the Condition Report (CR) in the Corrective Action Program.

NOTE 1 – In deciding if immediate notification is required, the SM or CRS should utilize the STE, Licensing, Engineering, and/or other personnel, as needed, to assist in reviewing and gathering pertinent information. Every attempt should be made to ensure information gathered is accurate and complete.

NOTE 2 – Radiological incidents meeting the criteria of 10CFR20.2201 and 20.2202 for reportability have been included in Attachment 4 as part of the 4 hour reporting category. Such events should be considered immediate reports (i.e., investigated and reported to the NRC as soon as practical, but not later than 4 hours).

NOTE 3 – Actual or attempted theft, sabotage, or diversion of radioactive material meeting the criteria of 10CFR37 have been included in Attachment 3 as part of the 4 hour reporting category. Such events should be considered immediate reports (i.e., investigated and reported to the applicable LLEAs and NRC as soon as practical, but not later than 4 hours).

4.1.7 The SM shall determine the appropriate reporting category (i.e., immediate, 1 hour, 4 hour, 8 hour, or 24 hour). Guidance is provided in Attachments 1 through 4 for determining the category for immediate notifications.

4.1.7.1 NUREG 1022 shall be referenced for all 10CFR50.72 reporting decisions.

4.1.7.2 The Certrec database may be accessed to review previous industry event notifications and to provide additional clarification on potentially reportable conditions.

4.1.8 In some cases, it may be necessary to undertake an evaluation in order to determine if an event or condition is reportable. Guidance provided in Procedure 0.5.OPS can be used to support operability and reportability determinations.

4.1.9 SM should contact Licensing to provide assistance in the reportability discussions, as needed, and to assist in the preparation of NRC Form 361 (Attachment 8, available at R:\cnsprocs\FORMS\NRC Form 361.doc).

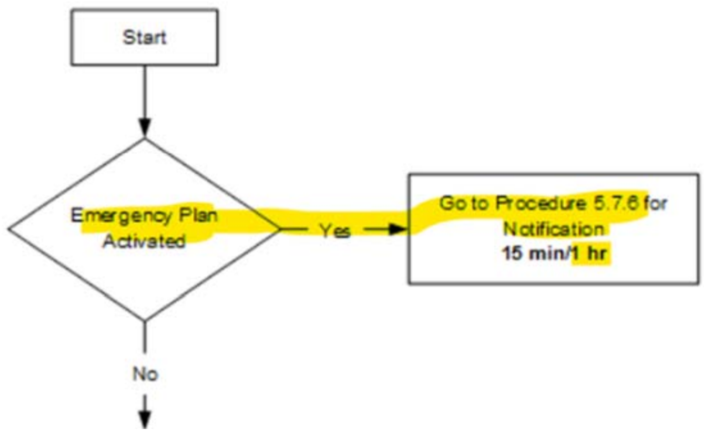
4.1.10 Proceed to Step 4.4 for events deemed to be reportable when not in a declared emergency.

4.1.11 If an emergency is declared and the TSC is activated, continue to monitor for non-emergency reportable events. The SM may direct the ENS Communicator to notify the NRC Operations Center within the time limits of 10CFR50.72 and log the notification of each reportable event. Attachments 8 and 9 are not required for these events.

From procedure 2.0.5

ATTACHMENT 1 REPORTABILITY FLOWCHART ⓟ[5]

ATTACHMENT 1 REPORTABILITY FLOWCHART ⓟ[1]



	EVENT or CONDITION	TIME	CLARIFYING INFORMATION	NUREG 1022 SECTION
0	50.72(a)(1)(i) The declaration of any Emergency Class specified in the Emergency Plan.	1 Hour	Reporting of these conditions is covered under Procedure 5.7.6. Additionally, an event or condition that meets an emergency class may meet one or more specific reporting requirements. Plant conditions which require declaration of an emergency classification and notification per Procedure 5.7.6 also require review under this procedure to ensure non-emergency reports continue to be made as required. Occasionally, a condition may be discovered that met the Emergency Plan criteria but no emergency was declared and the basis for the emergency class no longer exists. An actual declaration of the emergency class is not necessary in this case. However, an ENS notification should still be made within 1 hour of discovery.	3.1.1

PROCEDURE 2.0.5 REVISION 52 PAGE 22 OF 91

1. ENTRY CONDITIONS [REFERENCE USE]

   1.1 EAL declared and notification required per EPIP 5.7.2.

2. INSTRUCTIONS [REFERENCE USE]

   2.1 Emergency Director (ED) **DIRECTS** Notification Report be prepared.©[9]

      2.1.1 IF completing INITIAL Notification Report with CNS-DOSE available,
      THEN **PERFORM** Attachment 1.

      2.1.2 IF completing FOLLOW-UP Notification Report with CNS-DOSE available,
      THEN **PERFORM** Attachment 2.

26. Shift Communicator in Control Room, or TSC ENS Communicator if NRC communications turned over, immediately **CONTACT** NRC HQ via ENS, but no later than 60 minutes after declaration of event.

   26.1 **PROVIDE** additional information to NRC in addition to that provided on Notification Report; examples may include following:

   - Reactor power and mode before/after emergency declaration.
   - Reason for declaring emergency.
   - Additional 10CFR50.72 categories that may be applicable.
   - Status of notification to NRC Resident Inspector.
   - Any off-site assistance that has been requested.
   - News release being planned.

Examination Outline Cross-Reference	**Level**	SRO
295025 (EPE 2) High Reactor Pressure / 3 Ability to determine and/or interpret the following as they apply to HIGH REACTOR PRESSURE: EA2.06 Reactor water level	**Tier#**	1
	Group#	1
	K/A #	295025 EA2.06
	Rating	3.8
	Revision	0
Revision Statement:		

Question 77

An Extended Loss of AC Power (ELAP) has just been declared.

EOP-1A is in use with the following conditions:

- Reactor Level -100 inches CFZ, lowering 1 inch/minute
- Reactor Pressure 1060 psig, slowly lowering
- Drywell Pressure 4 psig, slowly rising
- **Only** RCIC is available for injection and is injecting at maximum flow rate

Which one of the following mitigation strategies is appropriate for these conditions?

A. Immediately transition to EOP-1B and reduce RPV pressure to 200 psig.

B. Immediately transition to EOP-1B and reduce RPV pressure to 400 psig.

C. Stabilize RPV pressure when it falls below 1050 psig AND remain in EOP-1A to align FLEX injection systems.

D. Stabilize RPV pressure when it falls below 1050 psig, remain in EOP-1A until level goes below TAF, then transition to EOP-2A and Emergency Depressurize.

Answer: A
Explanation: Reactor pressure is above the EOP-1A entry condition, 1050 psig. This question requires interpreting a lowering reactor water level with respect to a high reactor pressure condition in order to determine the appropriate EOP action.

RPV water level is below the normal EOP-1A control band, +3” to +54”, and lowering with the only available injection system at maximum flow rate. EOP-1A step RC/L-2 2nd override states if anticipated that available injection cannot assure adequate core cooling, transition to EOP-1B. With level above -158”, EOP-1B step RC/P-3 requires reducing pressure per note 31, which requires a pressure control band of 150-300 psig for RCIC injection.

Distracters:

Answer B is plausible because transition to EOP-1B is required per EOP-2A step RC/L-2 2nd override, and if HPCI was being used, the appropriate pressure band would be 150-450 psig. It is wrong because for RCIC, EOP-1B requires reducing pressure to 150-300 psig. 400 psig given in this distractor is above the pressure band for RCIC, which is the only injection system available.

Answer C is plausible because EOP-1A step RC/P-5 requires stabilizing pressure below 1050 psig and ELAP conditions warrant alignment of FLEX systems for required safety functions. It is wrong because level is lowering with the only injection source injecting at maximum rate, and EOP-1A step RC/L-2 2nd override states if anticipated that available injection cannot assure adequate core cooling, transition to EOP-1B.

Answer D is plausible because EOP-1A step RC/P-5 requires stabilizing pressure below 1050 psig and ED is required when level goes below -158” per EOP-1A step RC/L-10. It is wrong because EOP-1A step RC/L-2 2nd override states if anticipated that available injection cannot assure adequate core cooling, transition to EOP-1B.

Technical References: EOP-1A [RPV Control](Rev 22), EOP-1B [Alternate Level/Pressure Control](Rev 2)

References to be provided to applicants during exam: none

Learning Objective: INT008-06-93 EO-14, Given plant conditions and EOP flowchart 1B, Alternate Level/Pressure Control, determine required actions.

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X

10CFR Part 55 Content:	55.41(b)(5)
Level of Difficulty:	3

SRO Only Justification:	
Requires assessment of plant conditions and selection of a procedure with which to proceed.	
PSA Applicability:	
N/A	

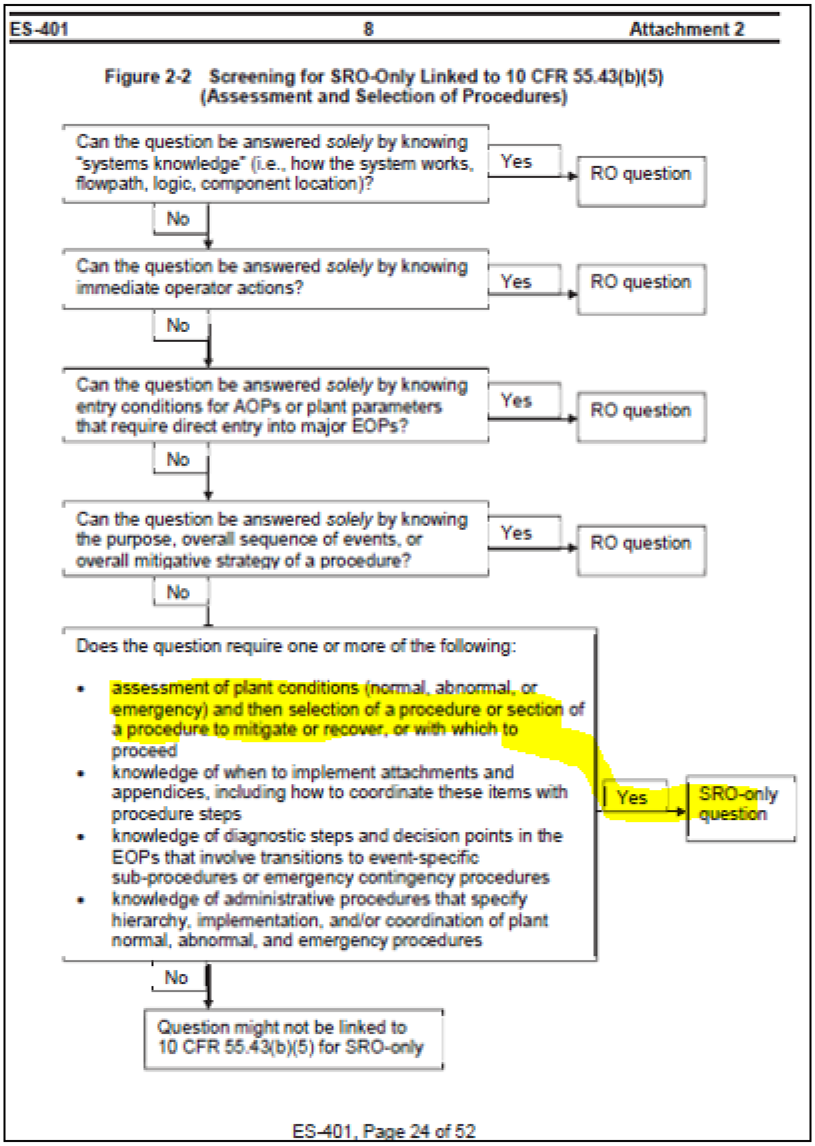

ES-401 8 Attachment 2

Figure 2-2 Screening for SRO-Only Linked to 10 CFR 55.43(b)(5) (Assessment and Selection of Procedures)

Can the question be answered *solely* by knowing "systems knowledge" (i.e., how the system works, flowpath, logic, component location)?

Yes

RO question

No

Can the question be answered *solely* by knowing immediate operator actions?

Yes

RO question

No

Can the question be answered *solely* by knowing entry conditions for AOPs or plant parameters that require direct entry into major EOPs?

Yes

RO question

No

Can the question be answered *solely* by knowing the purpose, overall sequence of events, or overall mitigative strategy of a procedure?

Yes

RO question

No

Does the question require one or more of the following:

- assessment of plant conditions (normal, abnormal, or emergency) and then selection of a procedure or section of a procedure to mitigate or recover, or with which to proceed
- knowledge of when to implement attachments and appendices, including how to coordinate these items with procedure steps
- knowledge of diagnostic steps and decision points in the EOPs that involve transitions to event-specific sub-procedures or emergency contingency procedures
- knowledge of administrative procedures that specify hierarchy, implementation, and/or coordination of plant normal, abnormal, and emergency procedures

Yes

SRO-only question

No

Question might not be linked to 10 CFR 55.43(b)(5) for SRO-only

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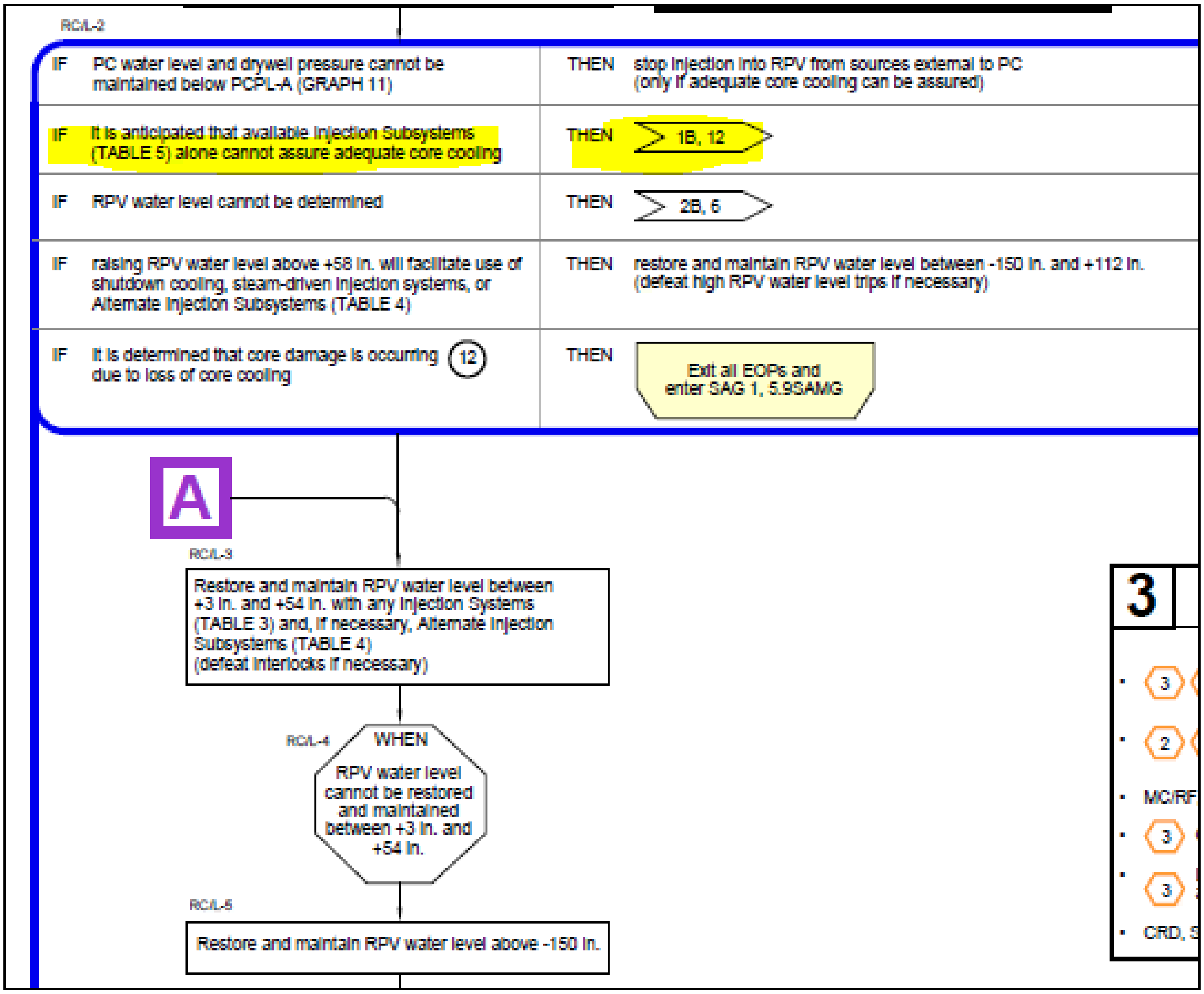
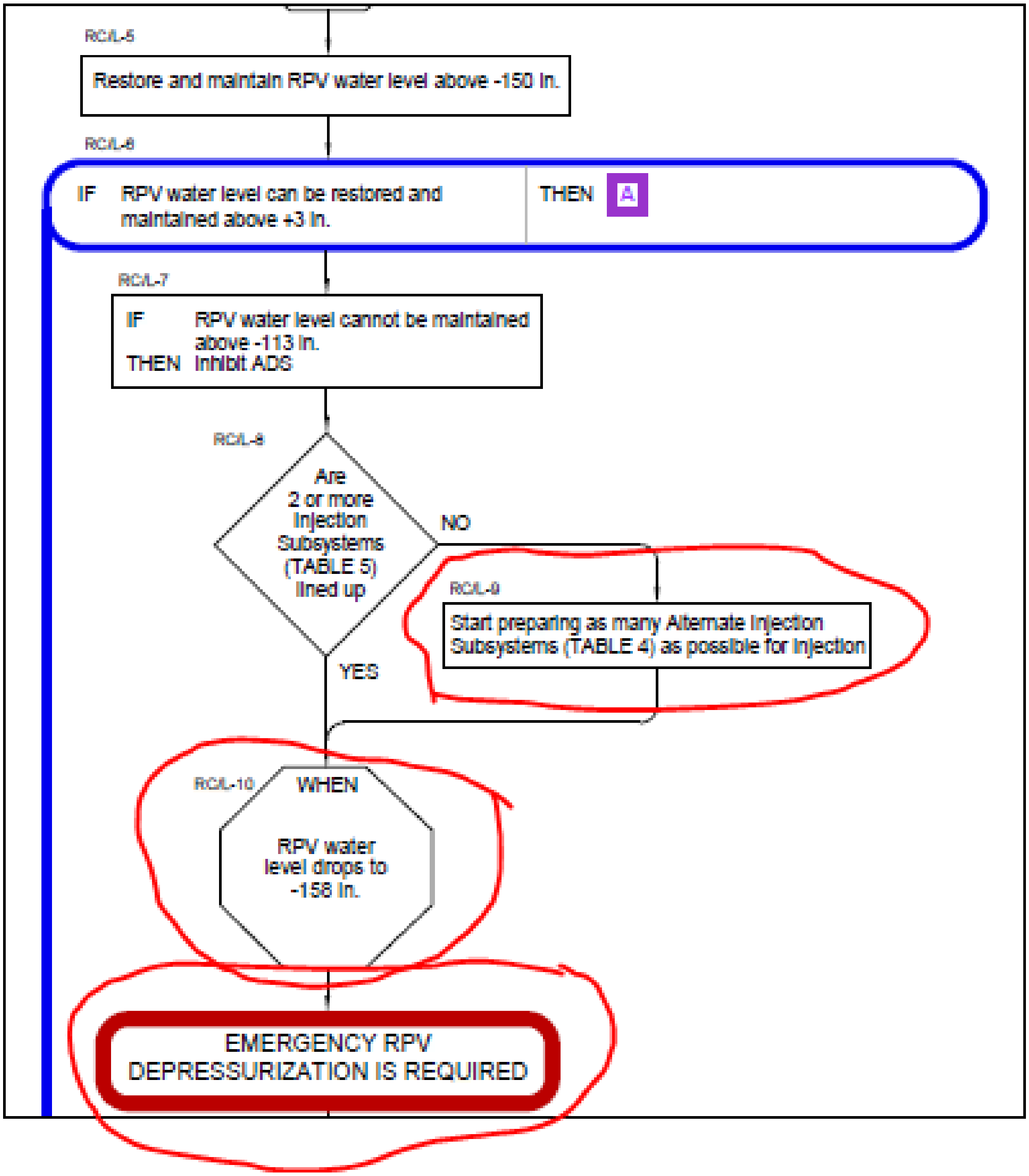
From EOP-1A


RC/L-2
IF PC water level and drywell pressure cannot be maintained below PCPL-A (GRAPH 11)
THEN stop injection into RPV from sources external to PC (only if adequate core cooling can be assured)
IF it is anticipated that available injection Subsystems (TABLE 5) alone cannot assure adequate core cooling
THEN 1B, 12
IF RPV water level cannot be determined
THEN 2B, 6
IF raising RPV water level above +58 in. will facilitate use of shutdown cooling, steam-driven injection systems, or Alternate Injection Subsystems (TABLE 4)
THEN restore and maintain RPV water level between -150 in. and +112 in. (defeat high RPV water level trips if necessary)
IF it is determined that core damage is occurring due to loss of core cooling
12
THEN
Exit all EOPs and enter SAG 1, 5.9SAMG
A
RC/L-3
Restore and maintain RPV water level between +3 in. and +54 in. with any Injection Systems (TABLE 3) and, if necessary, Alternate Injection Subsystems (TABLE 4) (defeat interlocks if necessary)
RC/L-4
WHEN
RPV water level cannot be restored and maintained between +3 in. and +54 in.
RC/L-5
Restore and maintain RPV water level above -150 in.
3
3
2
MC/RF
3
3
CRD, S

From EOP-1A



RC/L-5
Restore and maintain RPV water level above -150 in.
RC/L-6
IF RPV water level can be restored and maintained above +3 in.
THEN
A
RC/L-7
IF RPV water level cannot be maintained above -113 in.
THEN Inhibit ADS
RC/L-8
Are 2 or more Injection Subsystems (TABLE 5) lined up
NO
YES
RC/L-9
Start preparing as many Alternate Injection Subsystems (TABLE 4) as possible for injection
RC/L-10
WHEN
RPV water level drops to -158 in.
EMERGENCY RPV DEPRESSURIZATION IS REQUIRED

From EOP-1B

RC/P-3

Reduce RPV pressure and control pressure in the preferred RCIC/HPCI Control Band (TABLE 31) using any RPV Depressurization Systems (TABLE 2)

(exceed 100°F/hr cooldown rate if necessary)
(defeat interlocks and exceed radioactivity release rate limits if necessary)

IF continuous IA/N2 supply to SRV accumulators becomes unavailable

THEN perform following:
- Pressure stabilization:
  1. Place each SRV control switch in AUTO
  2. Prevent Low-Low Set actuation
- Depressurization: depressurize with sustained SRV opening

31	RCIC / HPCI Control Band
RCIC 150 to 300 psig	HPCI (in batch feed mode) 150 to 450 psig

Examination Outline Cross-Reference	Level	SRO
215005 (SF7 PRMS) Average Power Range Monitor/Local Power Range Monitor 2.2.38 Knowledge of conditions and limitations in the facility license.	Tier#	2
	Group#	1
	K/A #	215005 G2.2.38
	Rating	4.5
	Revision	0
Revision Statement:		

Question 78

The plant is at 100% power.

It is discovered that due to an administrative error, quarterly (92 days) surveillance 6.1APRM.303 [APRM Channel Functional Test Mode Switch in RUN (DIV 1)] has exceeded its drop dead date.

With respect to TS 3.3.1.1 [RPS Instrumentation], ONLY…

Which of the following statements identifies the MINIMUM TS requirements regarding RPS operability pending satisfactory performance of the surveillance?

A. Immediately enter appropriate Condition(s) of TS 3.3.1.1 for channel(s) inoperable with trip capability maintained.

B. Immediately enter appropriate Condition(s) of TS 3.3.1.1 for channel(s) inoperable with trip capability NOT maintained.

C. APRMs may be considered operable for up to 92 days from discovery only if an acceptable risk evaluation is performed within 24 hours and the risk managed.

D. APRMs may be considered operable for up to 115 days from discovery only if an acceptable risk evaluation is performed within 24 hours and the risk managed.

Answer: C

Explanation:
This question requires a determination of operability given a missed RPS surveillance. An exception to SR 3.0.1, SR 3.0.3 states when failure to comply with a surveillance frequency is discovered, declaring the LCO not met may be delayed for 24 hours or up to the surveillance frequency, whichever is greater, to allow time to perform the surveillance. If delayed greater than 24 hours, a risk evaluation must be performed

and the risk managed. The surveillance in question has a 92 day frequency. Therefore, the minimum requirement is to perform a risk evaluation within 24 hours to allow delaying entry into TS 3.3.1.1 action for up to 92 days, and answer C is correct.

Drop dead date, as reflected in the stem, is used in procedure 2.0.4 and refers to the date a surveillance exceeds its required test frequency, including any allowable frequency extension.

Distracters:
Answer A is plausible since an examinee may assume failure to comply with the specified surveillance frequency is the same as failing a surveillance requirement and requires immediately declaring the equipment inoperable per SR 3.0.1. Answer A reflects TS 3.3.1.1 Condition A. Only Division 1 APRMs are tested by the subject surveillance, so this answer will be plausible to the examinee who does not know the provisions of SR 3.0.3 and does not understand the TS Bases definition of trip capability. Answer A is wrong because the stem asks for the minimum requirement, which would be to delay entry into TS 3.3.1.1 actions as allowed by SR 3.0.3 and SR 3.0.1.

Answer B is plausible to the examinee who assumes failure to comply with the specified surveillance frequency is the same as failing a surveillance requirement and requires immediately declaring the equipment inoperable per SR 3.0.1. Answer B is also plausible because trip capability would be lost if all Division 1 APRMs were inoperable and untripped, which would require entry into both Conditions A and C of TS 3.3.1.1. Answer B is wrong for the same reason given for distractor A

Answer D is plausible because the examinee may attempt to apply surveillance frequency extension per SR 3.0.2, 1.25 times the specified frequency, which is inappropriate in this situation. The 115 days in answer D is derived by multiplying 92 times 1.25. The surveillance frequency extension of SR 3.0.2 does not apply to SR 3.0.3 requirements.

Technical References: TS 3.3.1.1 [RPS Instrumentation, SR 3.0.1, SR 3.0.3, SR 3.3.1.1.9; TRM Appendix B [Surveillance Frequency Control Program]
Procedure 6.1APRM.303 [APRM Channel Functional Test Mode Switch in RUN (DIV 1)](Rev 20)

References to be provided to applicants during exam: none

Learning Objective:
INT00705010010200 Given plant conditions and a Specification, apply the rules of Section 3.0 to determine appropriate actions.
COR002-21-02 Obj. LO-2, Given conditions and/or parameters associated with the RPS, determine if related Technical Specification and Technical Requirements Manual Limiting Condition for Operations are met.

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	12/2015 NRC Q#77
	New	

Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.43(b)(2)	
Level of Difficulty:	3	
SRO Only Justification:		
This requires application of Tech Spec generic LCO SR 3.0.3.		
PSA Applicability:		
Top 10 Risk Significant System - RPS		

12/2015 NRC ILT Q#77

Question 77

The plant is at rated power.

It is discovered that **quarterly** surveillance (92 days) 6.2RPS.301 {Manual Scram Functional Test (DIV 2)} has exceeded its Tech Spec late date due to an administrative error.

Which of the following statements identifies the MINIMUM Tech Spec requirements regarding RPS operability pending performance of the surveillance?

TS 3.3.1.1:

- *Condition A – One or more required channels inoperable.*
- *Condition C – One or more Functions with RPS trip capability not maintained.*

A. ONLY TS 3.3.1.1 Condition A must be immediately entered.

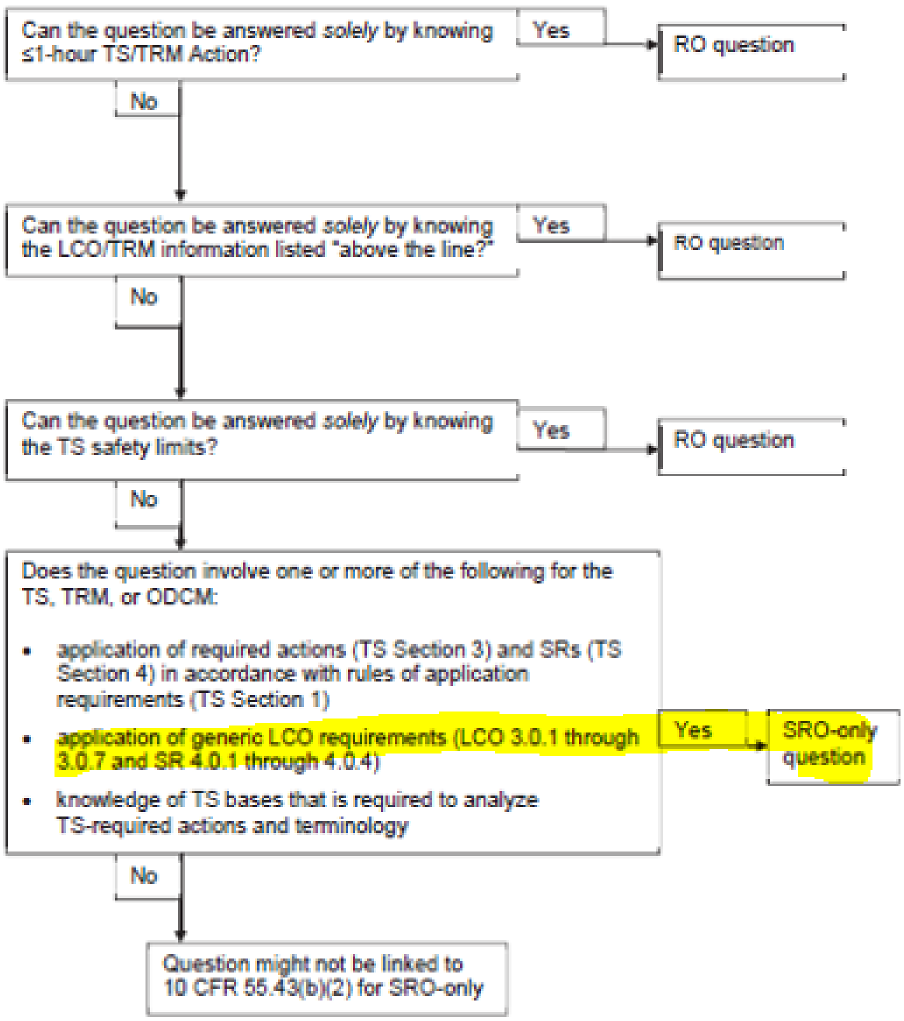
B. BOTH TS 3.3.1.1 Condition A and Condition C must be entered immediately.

C. RPS may be considered operable for up to 92 days from discovery only if an acceptable risk evaluation is performed within 24 hours and the risk managed.

D. RPS may be considered operable for up to 115 days from discovery only if an acceptable risk evaluation is performed within 24 hours and the risk managed.

Answer:
C. RPS may be considered operable for up to 92 days from discovery only if an acceptable risk evaluation is performed within 24 hours and the risk managed.

Figure 2-1 Screening for SRO-Only Linked to 10 CFR 55.43(b)(2) (Technical Specifications)



PROCEDURE 6.1APRM.303 REVISION 20 PAGE 24 OF 27

ATTACHMENT 2 INFORMATION SHEET

ATTACHMENT 2 INFORMATION SHEET

1. SURVEILLANCE REQUIREMENTS - TECHNICAL SPECIFICATIONS

1.1 This procedure satisfies the following for APRMs A/C/E:

1.1.1 SR 3.3.1.1.9 for Table 3.3.1.1-1, Function 2b.

1.1.2 SR 3.3.1.1.9 for Table 3.3.1.1-1, Function 2c.

1.1.3 SR 3.3.1.1.9 for Table 3.3.1.1-1, Function 2d.

1.1.4 SR 3.3.1.1.9 for Table 3.3.1.1-1, Function 2e.

2. SURVEILLANCE REQUIREMENTS - TECHNICAL REQUIREMENTS MANUAL

2.1 This procedure satisfies the following for APRMs A/C/E:

2.1.1 Part of TSR 3.3.1.5 for Table T3.3.1-1, Function 3a.

2.1.2 Part of TSR 3.3.1.5 for Table T3.3.1-1, Function 3c.

2.1.3 Part of TSR 3.3.1.5 for Table T3.3.1-1, Function 3d.

3. DISCUSSION

INFORMATION ONLY

Surveillance Frequency Control Program

List of Surveillance Frequencies and Bases

Surv. Req.	Description	Freq.	Frequency Bases	STIC Eval. #
3.3.1.1.4	Perform a functional test of each RPS channel test switch.	7 days	The Frequency is based on the reliability analysis of MDE-94-0485 (Technical Specification Improvement Analysis for the Reactor Protection System for Cooper Nuclear Station, April 1985). The RPS channel test switches are not specifically credited in the accident analysis. However, because the Manual Scram Functions at CNS were not configured the same as the generic model in NEDC-30851-P-A (Technical Specification Improvement Analysis for BWR Reactor Protection System, March 1988), the RPS channel test switches were included in the analysis in MDE-94-0485 (Technical Specification Improvement Analysis for the Reactor Protection System for Cooper Nuclear Station, April 1985). MDE-94-0485 concluded that the Surveillance Frequency extensions for RPS Functions, described in NEDC-30851-P-A, were not affected by the difference in configuration, since each automatic RPS channel has a test switch which is functionally the same as the manual scram switches in the generic model.	None.
3.3.1.1.6	Verify the IRM and APRM channels overlap.	7 days	A Frequency of 7 days is reasonable based on engineering judgment and the reliability of the IRMs and APRMs.	None.
3.3.1.1.7	Adjust the channel to conform to a calibrated flow signal.	31 days	The Frequency is based on engineering judgment, operating experience, and the reliability of this instrumentation.	None.
3.3.1.1.8	Calibrate the local power range monitors.	1000 MWD/T average core exposure	The Frequency is based on operating experience with LPRM sensitivity changes.	None.
3.3.1.1.9	Perform CHANNEL FUNCTIONAL TEST.	92 days	The Frequency is based on the reliability analysis of NEDC-30851-P-A (Technical Specification Improvement Analysis for BWR Reactor Protection System, March 1988).	None.
3.3.1.1.10	Perform CHANNEL	184 days	The Frequency is based upon the assumption of a 184 day calibration interval in the	None.

3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

SR 3.0.1

SRs shall be met during the MODES or other specified conditions in the Applicability for individual LCOs, unless otherwise stated in the SR. Failure to meet a Surveillance, whether such failure is experienced during the performance of the Surveillance or between performances of the Surveillance, shall be failure to meet the LCO. Failure to perform a Surveillance within the specified Frequency shall be failure to meet the LCO except as provided in SR 3.0.3. Surveillances do not have to be performed on inoperable equipment or variables outside specified limits.

SR 3.0.2

The specified Frequency for each SR is met if the Surveillance is performed within 1.25 times the interval specified in the Frequency, as measured from the previous performance or as measured from the time a specified condition of the Frequency is met.

For Frequencies specified as "once," the above interval extension does not apply.

If a Completion Time requires periodic performance on a "once per . . ." basis, the above Frequency extension applies to each performance after the initial performance.

Exceptions to this Specification are stated in the individual Specifications.

SR 3.0.3

If it is discovered that a Surveillance was not performed within its specified Frequency, then compliance with the requirement to declare the LCO not met may be delayed, from the time of discovery, up to 24 hours or up to the limit of the specified Frequency, whichever is greater. This delay period is permitted to allow performance of the Surveillance. A risk evaluation shall be performed for any Surveillance delayed greater than 24 hours and the risk impact shall be managed.

(continued)

6.6 List Surveillance Procedures not performed as scheduled, including those from previous shifts not yet completed along with drop dead date.

6.7 Prior to end of shift, crew supervision shall verify on-coming personnel are qualified to stand watch.

6.8 Each performer shall initial for the portion of the attachment performed signifying lineup is correct for current plant status. Crew supervision shall review the checklist, resolve any discrepancies, and sign for off-going shift. Attachment 2 or 3 will be given to the on-coming SM to complete.

6.9 Performer shall record time system status check is completed for all systems.

6.10 Use of the System Status Checklist during shift turnover and attendant briefings will ensure status of vital safety systems and critical plant parameters are observed or communicated to both the on-coming and off-going watch-standers.

6.11 On-coming shift shall review System Status Checklist, Attachment 2 or 3, within 2 hours of relieving watch, noting any discrepancies. At least one on-coming Control Room Operator and crew supervision shall sign the completed checklist.

6.12 Completed checklists shall be controlled and retained per Procedure 1.9.

Examination Outline Cross-Reference	**Level**	SRO
215002 (SF7 RBMS) Rod Block Monitor 2.2.22 Knowledge of limiting conditions for operations and safety limits.	**Tier#**	2
	Group#	2
	K/A #	215002 G2.2.22
	Rating	4.7
	Revision	0
Revision Statement:		

Question 79

Reference Provided

The plant is at 60% power with Rod 26-27 selected.

MCPR is 1.69 with NO peripheral control rod selected.

A Condition Report identifies actual upscale trip setpoints installed for the Rod Block Monitor are:

	Low	Intermediate	High
Channel A	118/125	113/125	109/125
Channel B	122/125	116/125	108/125

(1) What is the MAXIMUM time allowed by TS 3.3.2.1 [Control Rod Block Instrumentation] to place one RBM channel in trip?

AND

(2) Assume LCO 3.0.3 is entered because completion times are NOT met for TS 3.3.2.1 required action for RBM. Which one of the following is the FIRST point reached during the power reduction required by LCO 3.0.3 that allows exiting TS 3.0.3?

A. (1) 1 hour
(2) ONLY when Mode 2 is entered

B. (1) 1 hour
(2) When power is reduced below 27.5%

C. (1) 25 hours
(2) ONLY when Mode 2 is entered

D. (1) 25 hours
(2) When power is reduced below 27.5%

Answer: D
Explanation: TS 3.3.2.1 requires two RBM channels operable when ≥27.5% power. TS Allowable values for RBM upscale trip setpoints are stated in the COLR and are: • ≤ 120/125 between Low Power Setpoint (≥ 27.5%) and Intermediate Power Setpoint (< 62.5%). • ≤ 115/125 between IPSP (≥ 62.5%) and High Power Setpoint (< 82.5%). • ≤ 110.5/125 above HPSP (≥ 82.5%). For the setpoints given in the stem, RBM channel B low range and intermediate range setpoints are above the allowable values. Therefore, channel B is inoperable. With one RBM channel inoperable, TS 3.3.2.1 Action A.1 applies, which requires restoring the channel operable within 24 hours. Then, Action B.1 applies, which requires placing one RBM channel in trip within 1 hour. 24 hrs + 1 hr = 25 hrs. There are no conditions specified in TS 3.3.2.1 if the completion time of TS 3.3.2.1 required actions A.1 and B.1 cannot be met, so LCO 3.0.3 would apply. LCO 3.0.3 states: When an LCO is not met and the associated ACTIONS are not met, an associated ACTION is not provided, or if directed by the associated ACTIONS, the unit shall be placed in a MODE or <u>other specified condition in which the LCO is not applicable</u>. Action shall be initiated within 1 hour to place the unit, as applicable, in: a. MODE 2 within 7 hours; b. MODE 3 within 13 hours; and c. MODE 4 within 37 hours. RBM is only required to be operable when power is ≥27.5%. Reducing power to <27.5% would place the unit in a specified condition in which LCO 3.3.2.1 is not applicable for RBM. At that point, TS 3.0.3 is exited. Entering Mode 2 is not required.
Distracters: Answer A part 1 is plausible because a variety of setpoints for the various ranges for RBM A and B are presented in the stem. The examinee who does not know the setpoints may choose this answer. This answer reflects TS 3.3.2.1 Action B.1 (both channels inoperable) to place one channel in trip within 1 hr. It is wrong because only channel B is inoperable. Therefore, the maximum time to place one RBM channel in trip is 25 hrs. Part 2 is plausible because LCO 3.0.3 states action shall be taken to place the unit in MODE 2 within 7 hours. It is wrong because LCO 3.0.3 is exited when power is lowered below the specified condition related to the applicability of TS 3.3.2.1 for RBM, ≥27.5%. Since RBM is not required operable below 27.5% power, further power reduction is not required.

Answer B part 1 is plausible and wrong for the reason stated for distractor A. Part 2 is correct. Answer C part 1 is correct Part 2 is plausible and wrong for the reason stated for distractor A.		
Technical References: TS 3.3.2.1 [Control Rod Block Instrumentation], TS 3.0.3, lesson plan COR002-24-02 [Ops Rod Block Monitor](Rev 22)		
References to be provided to applicants during exam: TS 3.3.2.1 LCO and Actions (pages 3.3-14 thru 3.3-16), only		
Learning Objective: COR002-24-02 Obj LO-4a, Describe the RBM design features and/or interlocks that provide for the following: Prevent control rod withdrawal; INT007-05-04 EO-3, Given a set of plant conditions that constitutes non-compliance with a Section 3.3 LCO, discuss the ACTIONS that are required; INT007-05-01 EO-2, Given plant conditions and a Specification, apply the rules of Section 3.0 to determine appropriate actions.		
Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.43(b)(2)	
Level of Difficulty:	3	
SRO Only Justification:		
This requires application of TS 3.3.2.1 required actions and TS 3.0.4.		
PSA Applicability:		
N/A		

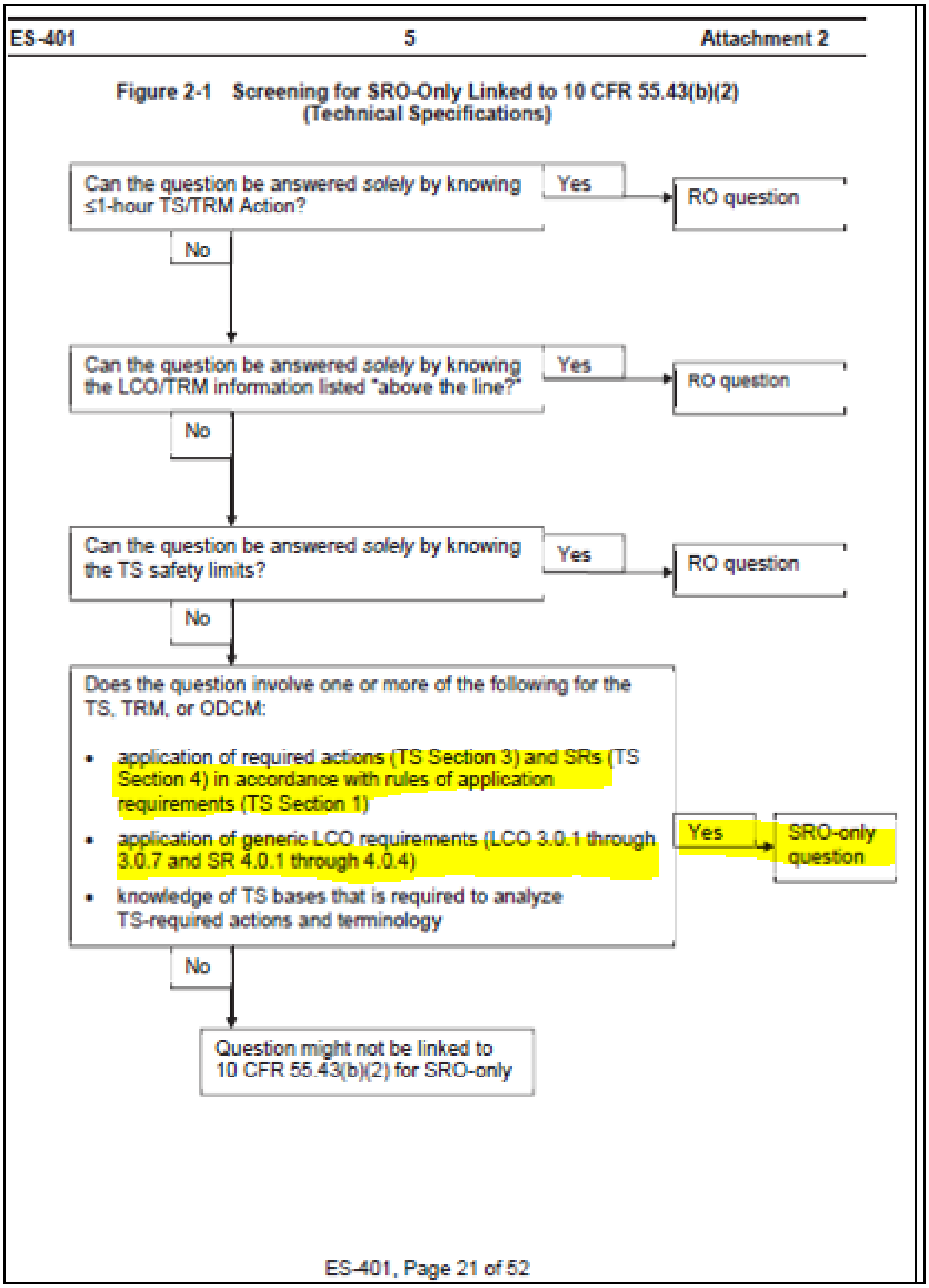


Figure 2-1 Screening for SRO-Only Linked to 10 CFR 55.43(b)(2)
(Technical Specifications)

3.3 INSTRUMENTATION

3.3.2.1 Control Rod Block Instrumentation

LCO 3.3.2.1 The control rod block instrumentation for each Function in Table 3.3.2.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.2.1-1.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One rod block monitor (RBM) channel inoperable.	A.1 Restore RBM channel to OPERABLE status.	24 hours
B. Required Action and associated Completion Time of Condition A not met. OR Two RBM channels inoperable.	B.1 Place one RBM channel in trip.	1 hour
C. Rod worth minimizer (RWM) inoperable during reactor startup.	C.1 Suspend control rod movement except by scram. OR	Immediately (continued)

[redacted]

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. One or more Reactor Mode Switch - Shutdown Position channels inoperable.	E.1 Suspend control rod withdrawal.	Immediately
	AND	
	E.2 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

-NOTES-

1. Refer to Table 3.3.2.1-1 to determine which SRs apply for each Control Rod Block Function.

2. When an RBM channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains control rod block capability.

SURVEILLANCE		FREQUENCY
SR 3.3.2.1.1	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

(continued)

Table 3.3.2.1-1 (page 1 of 1)
Control Rod Block Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Rod Block Monitor				
a. Low Power Range — Upscale	(a)	2	SR 3.3.2.1.1 SR 3.3.2.1.4 SR 3.3.2.1.5(b)(c)	(j)
b. Intermediate Power Range — Upscale	(d)	2	SR 3.3.2.1.1 SR 3.3.2.1.4 SR 3.3.2.1.5(b)(c)	(j)
c. High Power Range — Upscale	(e),(f)	2	SR 3.3.2.1.1 SR 3.3.2.1.4 SR 3.3.2.1.5(b)(c)	(j)
d. Inop	(f),(g)	2	SR 3.3.2.1.1	NA
e. Downscale	(f),(g)	2	SR 3.3.2.1.1 SR 3.3.2.1.5	≥ 92/125 divisions of full scale
2. Rod Worth Minimizer	1(h),2(h)	1	SR 3.3.2.1.2	NA

(a) THERMAL POWER ≥ 27.5% and < 62.5% RTP and MCPR < 1.70 and no peripheral control rod selected.

(b) If the as-found channel setpoint is outside its predefined as-found tolerance, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

(c) The instrument channel setpoint shall be reset to a value that is within the as-left tolerance around the Limiting Trip Setpoint (LTSP) at the completion of the surveillance; otherwise, the channel shall be declared inoperable. Setpoints more conservative than the LTSP are acceptable provided that the as-found and as-left tolerances apply to the actual setpoint implemented in the Surveillance procedures (Nominal Trip Setpoint) to confirm channel performance. The Limiting Trip Setpoint and the methodologies used to determine the as-found and the as-left tolerances are specified in the Technical Requirements Manual.

(d) THERMAL POWER ≥ 62.5% and < 82.5% RTP and MCPR < 1.70 and no peripheral control rod selected.

(e) THERMAL POWER ≥ 82.5% and < 90% RTP and MCPR < 1.70 and no peripheral control rod selected.

(f) THERMAL POWER ≥ 90% RTP and MCPR < 1.40 and no peripheral control rod selected.

(g) THERMAL POWER ≥ 27.5% and < 90% RTP and MCPR < 1.70 and no peripheral control rod selected.

(h) With THERMAL POWER ≤ 9.85 RTP.

(i) Reactor mode switch in the shutdown position.

(j) Less than or equal to the Allowable Value specified in the COLR.

Lesson Number: COR002-24-02	Revision: 22

(5) The unit automatically bypasses the RBM channel when reactor power is below 27.5%, since the RBM is not needed below that point (RWE cannot result in exceeding Safety Limit MCPR).

LO-04a
LO-06f

g. Rod Block Trip Units

(1) The inop trip unit trips upon:

(a) No balance

(b) Too few inputs (less than 50% of assigned input LPRMs operable)

(c) Card pulled

(d) More than one rod selected

(e) RBM Mode Switch not in "OPERATE".

(2) The downscale trip setpoint is set at 92/125.

(3) The upscale trip setpoints are:

(a) $\leq$ 120/125 between Low Power Setpoint ($\geq$ 27.5%) and Intermediate Power Setpoint (< 62.5%).

(b) $\leq$ 115/125 between IPSP ($\geq$ 62.5%) and High Power Setpoint (< 82.5%).

(c) $\leq$ 110.5/125 above HPSP ($\geq$ 82.5%).

(4) Each of the three trip units has the capability to cause a rod withdrawal block in the RMCS.

(5) Under certain conditions following a trip signal being initiated, the trip units can be reset automatically. (Refer to section II. H., Trip Units.)

3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

LCO 3.0.1 LCOs shall be met during the MODES or other specified conditions in the Applicability, except as provided in LCO 3.0.2 and LCO 3.0.7.

LCO 3.0.2 Upon discovery of a failure to meet an LCO, the Required Actions of the associated Conditions shall be met, except as provided in LCO 3.0.5 and LCO 3.0.6.

If the LCO is met or is no longer applicable prior to expiration of the specified Completion Time(s), completion of the Required Action(s) is not required, unless otherwise stated.

LCO 3.0.3 When an LCO is not met and the associated ACTIONS are not met, an associated ACTION is not provided, or if directed by the associated ACTIONS, the unit shall be placed in a MODE or other specified condition in which the LCO is not applicable. Action shall be initiated within 1 hour to place the unit, as applicable, in:

a. MODE 2 within 7 hours;

b. MODE 3 within 13 hours; and

c. MODE 4 within 37 hours.

Exceptions to this Specification are stated in the individual Specifications.

Where corrective measures are completed that permit operation in accordance with the LCO or ACTIONS, completion of the actions required by LCO 3.0.3 is not required.

LCO 3.0.3 is only applicable in MODES 1, 2, and 3.

Examination Outline Cross-Reference	**Level**	SRO
215001 (SF7 TIP) Traversing In-Core Probe 2.4.4 Ability to recognize abnormal indications for system operating parameters that are entry-level conditions for emergency and abnormal operating procedures.	**Tier#**	2
	Group#	2
	K/A #	215001 G2.4.4
	Rating	4.7
	Revision	1
Revision Statement: Modified question to ensure it cannot be answered solely using fundamental knowledge, knowledge of AOP entry conditions, or knowledge of overall mitigative strategy of a procedure to elevate to SRO-level IAW NRC CE comments during “free review”.		

Question 80

The plant was operating at 100% power with a TIP run (OD-1) in progress when a TIP isolation signal was received.

TIP C ball valve did not close.

(1) Which procedure contains steps to fire the TIP SQUIB VALVE for TIP C?

AND

(2) Under which condition is firing the TIP SQUIB VALVE for TIP C required?

A. (1) 4.1.4 [Traversing In-Core Probe System]
(2) Drywell pressure 2 psig due to a steam leak

B. (1) 4.1.4 [Traversing In-Core Probe System]
(2) Reactor water level -100 inches due to loss of high pressure systems

C. (1) 2.1.22 [Recovering from a Group Isolation], Att. 1 [Group Isolation Hard Card]
(2) Drywell pressure 2 psig due to a steam leak

D. (1) 2.1.22 [Recovering from a Group Isolation], Att. 1 [Group Isolation Hard Card]
(2) Reactor water level -100 inches due to loss of high pressure systems

Answer: A
Explanation: Procedure 4.1.4 contains actions necessary to effect TIP isolation in the abnormal event automatic isolation on a Group 2 isolation signal fails. The operator is instructed to first attempt to retract the TIP and close the isolation ball valve. If that is not successful, step 6.3 directs actuating the affected TIP squib (shear) valve as a contingency. This contingency, operating the TIP squib valve, is conditional and is

directed only if an attempt to isolate the TIP ball valve fails AND if there are indications of a reactor coolant leak in the drywell. Drywell pressure 2 psig due to a steam leak represents a reactor coolant leak in the Drywell, so actuating the TIP squib valve is required.

Distracters:
Answer B part 1 is correct. Part 2 is plausible because reactor water level below +3" is a Group 2 isolation signal. TIP isolation is included in Group 2. A Group 2 isolation signal could be indicative of a reactor coolant leak in the DW, since the setpoints for Group 2 are DW pressure ≥1.84 psig and reactor water level ≤+3". An examinee who confuses the relationship between Group 2 isolation signals an the cause of the isolation signal may choose this answer. It is wrong because Procedure 4.1.4 states there must be indications of a reactor coolant leak in the DW to actuate the TIP squib valve, but level is low only due to loss of high pressure feed in this answer.

Answer C part 1 is plausible because Procedure 2.1.22 Att. 1 Group Isolation Hard Card is the tool operators are required to use to verify required isolations have occurred and gone to completion. Section 5.2 is performed to verify a Group 2 isolation and instructs the operator to ensure all associated automatic actions have occurred. The word "Ensure" at CNS instructs the operator to verify automatic action has occurred, or if not, to manually effect the isolation. This answer is wrong because procedure 2.1.22 only instructs the operator to ensure TIP ball valves have closed. It does not inform the operator how to attempt to close TIP ball valves if a TIP is inserted, and it does not provide any instructions related to the TIP squib valve. It also does not refer the operator to procedure 4.1.4 if TIP isolation has not occurred. Part 2 is correct.

Answer D part 1 is plausible and wrong for the reason given for distractor C. Part 2 is plausible and wrong for the reason given for distractor B.

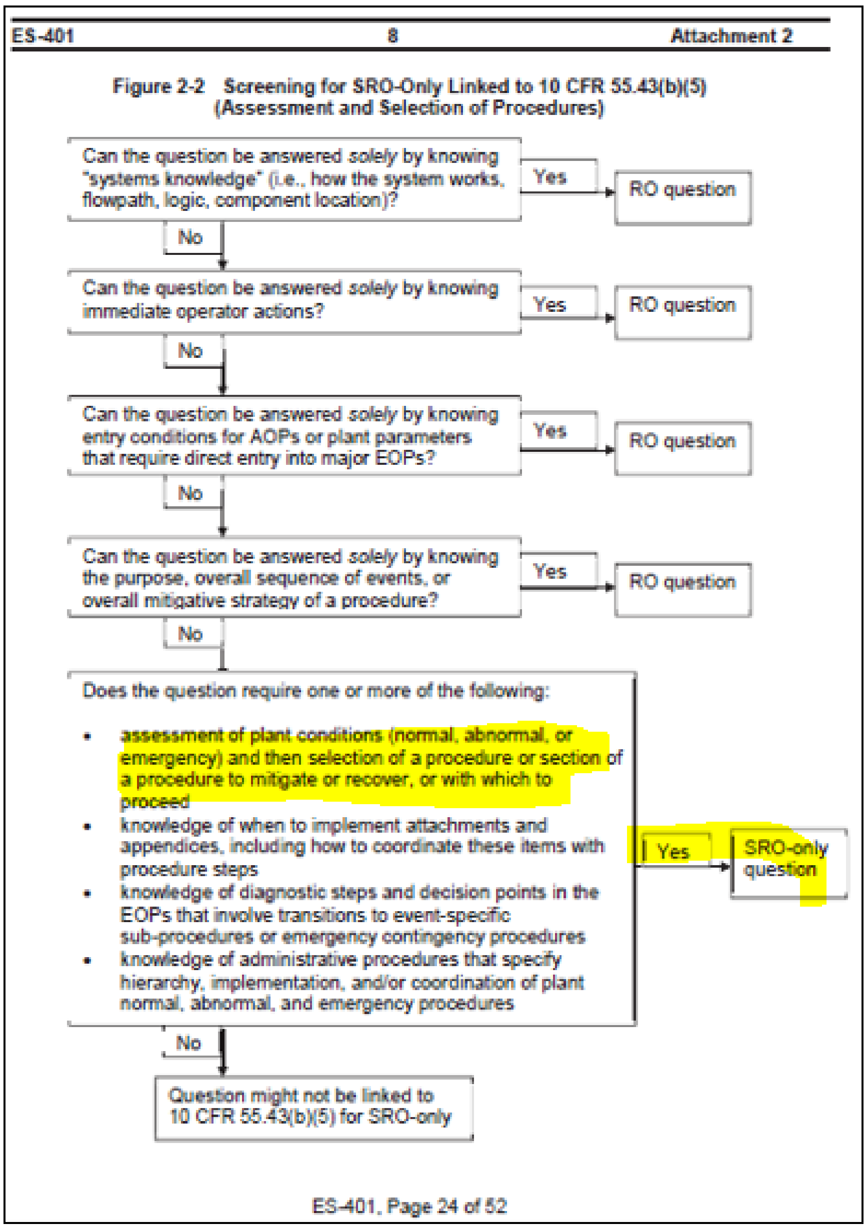
Technical References: Procedure 2.1.22 [Recovering from a Group Isolation](Rev 62), 4.1.4 [Traversing In-Core Probe System](Rev 37),

References to be provided to applicants during exam: none

Learning Objective: COR002-31-02 EO-11, Describe the TIP system design features and/or interlocks that provide for the following: Primary containment isolation

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.43(b)(5)	

Level of Difficulty:	3
SRO Only Justification:	
Part 1 requires evaluation of plant conditions and selection of a procedure with which to proceed. Procedure selection involves SRO-level knowledge because it requires knowledge of procedure content versus knowledge of the procedure's overall mitigative strategy or purpose. Part 2 requires detailed knowledge of procedure content related to assessment of plant conditions.	
PSA Applicability	
Top 10 Risk Significant System - PCIS	



C. Facility Licensee Procedures Required To Obtain Authority for Design and Operating Changes in the Facility [10 CFR 55.43(b)(3)]

Some examples of SRO exam items for this topic include the following:

- screening and evaluation processes under 10 CFR 50.59, "Changes, Tests and Experiments"
- administrative processes for temporary modifications
- administrative processes for disabling annunciators
- administrative processes for the installation of temporary instrumentation
- processes for changing the plant or plant procedures

Section IV provides an example of a satisfactory SRO-only question related to this topic.

D. Radiation Hazards That May Arise during Normal and Abnormal Situations, including Maintenance Activities and Various Contamination Conditions [10 CFR 55.43(b)(4)]

Some examples of SRO exam items for this topic include the following:

- process for gaseous/liquid release approvals (i.e., release permits)
- analysis and interpretation of radiation and activity readings as they pertain to the selection of administrative, normal, abnormal, and emergency procedures
- analysis and interpretation of coolant activity, including comparison to emergency plan criteria and/or regulatory limits

SRO-only knowledge should not be claimed for questions that can be answered *solely* based on RO knowledge of radiological safety principles (e.g., radiation work permit requirements, stay time, and DAC hours).

E. Assessment of Facility Conditions and Selection of Appropriate Procedures during Normal, Abnormal, and Emergency Situations [10 CFR 55.43(b)(5)]

This 10 CFR 55.43 topic involves both (1) assessing plant conditions (normal, abnormal, or emergency) and then (2) selecting a procedure or section of a procedure to mitigate or recover, or with which to proceed. One area of SRO-level knowledge (with respect to selecting a procedure) is knowledge of the content of the procedure versus knowledge of the procedure's overall mitigative strategy or purpose.

6.2.2 **PLACE** MAN. VALVE CONTROL switch to CLOSED; N/A for TIP ball valves not performed.

TIP A [ ]; TIP B [ ]; TIP C [ ]; TIP D [ ]

Independent Verification

6.2.3 **ENSURE** green BALL VALVE CLOSED light on VALVE CONTROL MONITOR on.

Performed By:	TIP A	TIP B	TIP C	TIP D
Verified By:	TIP A	TIP B	TIP C	TIP D

6.2.4 **ENSURE** MANUAL switch to OFF.

TIP A [ ]; TIP B [ ]; TIP C [ ]; TIP D [ ]

6.2.5 **ENSURE** MODE switch to OFF.

TIP A [ ]; TIP B [ ]; TIP C [ ]; TIP D [ ]

NOTE – Control Room Key Numbers 78, 79, 80, and 81 are required to operate keylock switches that fire shear valves.

Critical Step

◆ 6.3 IF attempt to close affected ball valves failed and there are indications of reactor coolant leak in drywell,
THEN **PERFORM** following for affected TIP drives:

6.3.1 **PLACE** TIP SQUIB VALVE to fire.

TIP A [ ]; TIP B [ ]; TIP C [ ]; TIP D [ ]

6.3.2 **VERIFY** amber SQUIB MONITOR light on.

TIP A [ ]; TIP B [ ]; TIP C [ ]; TIP D [ ]

6.3.3 **VERIFY** amber SHEAR VLV MONITOR light on.

TIP A [ ]; TIP B [ ]; TIP C [ ]; TIP D [ ]

5.2 Upon full Group 2 Isolation, ensure following actions have occurred:

5.2.1 If RHR in Shutdown Cooling, running RHR pump has tripped.

5.2.2 Following valves have closed:

NOTE – All valve positions can be determined from containment mimic on Panel 9-3 unless otherwise specified.

5.2.2.1 RHR-SSV-95 (Div 1), RHR SAMPLE VALVE.

5.2.2.2 RHR-SSV-96 (Div 1), RHR SAMPLE VALVE.

5.2.2.3 RHR-SSV-60 (Div 2), RHR SAMPLE VALVE.

5.2.2.4 RHR-SSV-61 (Div 2), RHR SAMPLE VALVE.

5.2.2.5 RHR-MO-57 (Div 1), RHR DISCH TO RW OUTBD VLV.

5.2.2.6 RHR-MO-67 (Div 2), RHR DISCH TO RW INBD VLV.

5.2.2.7 RW-AO-83 (Div 2), DISCH VLV.

5.2.2.8 RW-AO-82 (Div 1), DISCH ROOT VLV.

5.2.2.9 RW-AO-95 (Div 2), DISCH VLV, if PASS sampling on sump not in-progress.

5.2.2.10 RW-AO-94 (Div 1), DISCH ROOT VLV, if PASS sampling on sump not in-progress.

5.2.2.11 Channel A TIP BALL VALVE.

5.2.2.12 Channel B TIP BALL VALVE.

5.2.2.13 Channel C TIP BALL VALVE.

5.2.2.14 Channel D TIP BALL VALVE.

5.2.2.15 RHR-MO-17 (Div 1), SHUTDOWN COOLING RHR SUPPLY OUTBD VLV, if RHR in Shutdown Cooling.

5.2.2.16 RHR-MO-18 (Div 2), SHUTDOWN COOLING RHR SUPPLY INBD VLV, if RHR in Shutdown Cooling.

5.2.2.17 RHR-MO-25A (Div 1), INBD INJECTION VLV (Panel 9-3 Benchboard), if RHR in Shutdown Cooling.

5.2.2.18 RHR-MO-25B (Div 2), INBD INJECTION VLV (Panel 9-3 Benchboard), if RHR in Shutdown Cooling.

5.2.2.36 PC-MO-1302 (Div 1), TORUS N_2 SUPPLY ISOLATION VLV (Panel P2), if not in OVERRIDE.

5.3 Determine isolation cause:

ISOLATION	ALLOWABLE VALUE	COMMENTS
Low Reactor Water Level	≥ 3"	
Drywell Pressure	≤ 1.84 psig	Ensure Group 6 Isolation.
RPS Power Supply Failure	Loss of power	

5.4 Refer to following procedures as necessary:

PROCEDURE	TITLE
2.1.5	Reactor Scram
2.4SDC	Shutdown Cooling Abnormal
2.4PC	Primary Containment Control
5.8	Emergency Operating Procedures (EOPs)

5.5 IF isolation signal cannot be reset within 1 hour, THEN remove drywell vent monitor from service per Procedure 2.2.61.

5.6 AFTER isolation cause has been determined and corrected, THEN reset Group 2 Isolation by turning Group ISOL RESET, CHANNEL A and CHANNEL B, switches (Panel 9-5) to right RESET position and then releasing to NOR.

5.7 Check Group 2, CHANNEL A Isolation lights turn on (Panel 9-5).

5.8 Check Group 2, CHANNEL B Isolation lights turn on (Panel 9-5).

5.9 Ensure drywell vent monitor in service per Procedure 2.2.61 and check drywell atmosphere activity on VBD-Q.

5.9.1 IF drywell atmosphere activity high, THEN notify Chemistry and Radiation Protection.

5.9.1.1 At Chemistry's or Radiation Protection's request, a small amount of drywell floor drain sump and drywell equipment drain sump water may be pumped to radwaste for sampling.

5.9.2 IF drywell atmosphere activity normal, THEN momentarily place following valve switches to OPEN (Panel 9-4):

5.9.2.1 RW-AO-82 and RW-AO-83.

5.9.2.2 RW-AO-94 and RW-AO-95.

Examination Outline Cross-Reference	Level	SRO
295024 High Drywell Pressure / 5 2.4.4 Ability to recognize abnormal indications for system operating parameters that are entry-level conditions for emergency and abnormal operating procedures.	Tier#	1
	Group#	1
	K/A #	295024 G2.4.4
	Rating	4.7
	Revision	
Revision Statement:		

Question 81

EOP-3A has been entered due to high Suppression Pool temperature from a failed open SRV.

- All legs of EOP-3A have been addressed by the CRS except for PC Pressure.

Drywell pressure is now 1.9 psig, rising slowly.

Which one of the following completes the statement below regarding the required CRS actions?

The CRS is required to ____(1)____ EOP-3A and address ____(2)____.

A. (1) re-enter
(2) the PC Pressure leg ONLY

B. (1) re-enter
(2) ALL legs

C. (1) continue in
(2) the PC Pressure leg ONLY

D. (1) continue in
(2) ALL legs

Answer: B
Explanation: Guidance for EOP execution given in the PSTG (ref. B-4-4) states anytime an EOP entry condition is exceeded, any associated EOP is required to be re-entered at the beginning, even if it had been entered previously due to another parameter. Another parameter exceeding its EOP entry condition may be indicative of degrading

conditions where specific EOP action may not have been required earlier but is now. Changes in one parameter may also be indicative that degradation is occurring in the another parameter/function that needs to be re-addressed. Therefore, Answer B is correct.

Distracters:

Answer A is incorrect due to all legs of EOP 3A being required to be addressed. This choice is plausible due to EOP entry condition being the primary focus for execution. The examinee that focuses on the re-entry condition or does not recognize the entry condition would select this answer.

Answer C is incorrect due to all legs of EOP 3A being required to be addressed following re-entry. This choice is plausible due to not recognizing the EOP entry condition making this a correct answer by only requiring continuing and addressing the leg that has not been addressed. The examinee that focuses on the re-entry condition OR does not recognize the EOP entry would select this answer.

Answer D is incorrect due to EOP 3A re-entry being required. This choice is plausible due to not recognizing the EOP entry condition making this a partially correct answer. The examinee that does not recognize EOP re-entry requirement and confuses whether all vs. the applicable leg is required to be addressed would select this answer.

Technical References: EOP-3A [Primary Containment Control](Rev 17), PSTG (AMP-TBD00 Technical Basis)(Rev 10)

References to be provided to applicants during exam: none

Learning Objective:

INT00806040010200 Discuss the method used to track progress in the flowcharts (place keeping).

INT00806130011100 Given plant conditions and EOP Flowchart 3A, PRIMARY CONTAINMENT CONTROL, determine required actions.

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	12/2015 ILT NRC Q#99
	New	
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.43(b)(5)	
Level of Difficulty:	2	
SRO Only Justification:		

This requires knowledge of administrative procedures that specify implementation of EOPs. It relates to proper EOP execution, which is an SRO function.
PSA Applicability:
N/A

12/2015 ILT NRC Q#99

Question 99

EOPs have been entered due to high Drywell Pressure from a small steam leak.

- All legs of EOP-1A have been addressed by the CRS.
- All legs of EOP-3A have been addressed by the CRS except for Torus Water Temperature.

Average Torus Water Temperature is now 96°F.

Which one of the following completes the statement below regarding the required CRS actions?

The CRS is required to ____(1)____ EOP-3A and address ____(2)____.

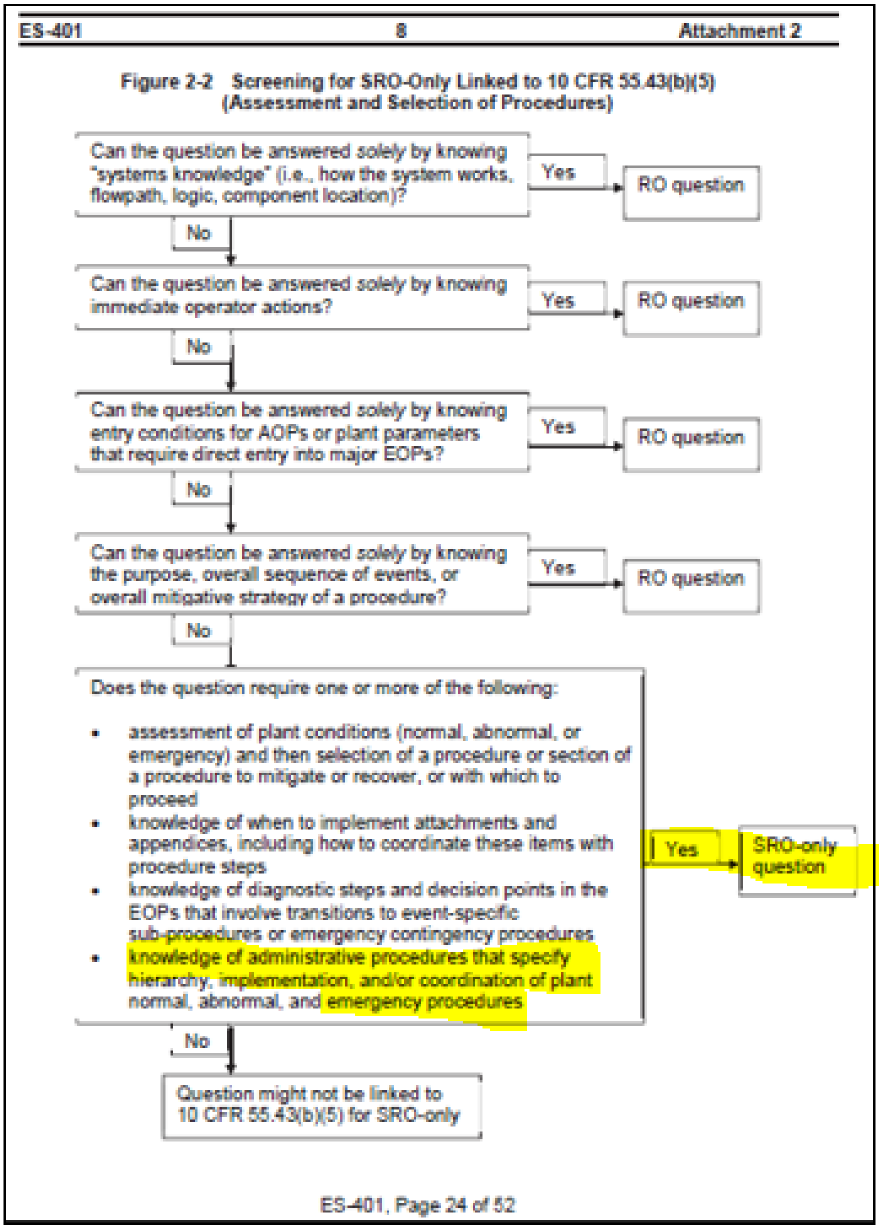
A. (1) re-enter
(2) the Torus Water Temperature leg ONLY

B. (1) re-enter
(2) ALL legs

C. (1) continue in
(2) the Torus Water Temperature leg ONLY

D. (1) continue in
(2) ALL legs

Answer:
B. (1) re-enter
(2) ALL legs



PRIMARY CONTAINMENT CONTROL

ANY OF FOLLOWING ENTRY CONDITIONS:

- drywell pressure above 1.84 psig
- PC H_2 concentration above 1%
- average drywell temperature above 150°F
- torus water level above +2 in.
- torus water level below -2 in.
- average torus water temperature above 95°F

PSTG/SATG Step

Each emergency operating procedure (EOP) developed from the PSTG should be entered whenever a defined entry condition occurs or an explicit direction to do so is encountered, even if the procedure has already been entered, unless instructions developed from the severe accident guidelines are being executed. EOPs may be exited when it has been determined that an emergency no longer exists.

Discussion

The PSTG entry conditions are based upon the values of key plant parameters rather than the existence of certain events. The conditions have been defined so as to be simple, operationally significant, unambiguous, readily identifiable, and familiar to control room operators. The specified setpoints also provide advance warning of potential emergency conditions, allowing action to be taken sufficiently early to prevent more severe consequences. The low RPV water level entry condition setpoint specified in the RPV Control guideline is an example: although RPV water level at the low level scram setpoint does not itself constitute an emergency condition, correct and prompt operator action may be required when this condition occurs to prevent core uncovery.

When an entry condition occurs, the corresponding procedure must be entered. If another entry condition for the same procedure occurs, the procedure must be reentered at the beginning, even if it is already being executed. If entry conditions for more than one procedure occur at the same time, the procedures must be executed concurrently.

Examination Outline Cross-Reference	Level	SRO
295001 (APE 1) Partial or Complete Loss of Forced Core Flow Circulation / 1 & 4 Ability to determine and/or interpret the following as they apply to PARTIAL OR COMPLETE LOSS OF FORCED CORE FLOW CIRCULATION: AA2.04 Individual jet pump flows: Not-BWR-1&2	Tier#	1
	Group#	1
	K/A #	295001 AA2.04
	Rating	3.1
	Revision	
Revision Statement:		

Question 82

Reference Provided

The plant was at 100% power on the 100% rod line when a transient resulted in the following indications:

• Reactor power	89%
• Total Core Flow [NBI-FRDPR-95]	76 Mlbm/hr
• Core Plate Pressure Drop [NBI-FRDPR-95]	13 psid
• Recirc Pump A Flow [RR-FR-163, Ch 1]	46 Kgpm
• Recirc Pump B Flow [RR-FR-163, Ch 2]	55 Kgpm
• JP #11 Flow [NBI-FI-87A]	4.3 Mlbm/hr
• JP #1 Flow [NBI-FI-87B]	2.9 Mlbm/hr
• JP #16 Flow [NBI-FI-87C]	4.3 Mlbm/hr
• JP #6 Flow [NBI-FI-87D]	3.7 Mlbm/hr

(1) Which one of the following failures caused these indications?

AND

(2) IAW Procedure 2.4RXPWR, if it is determined the plant cannot reach Mode 3 within the time required for this condition per Procedure 2.1.4 [Normal Shutdown], which procedure is required to be entered?

A. (1) RPV shroud cracking
(2) Shut down IAW Procedure 2.1.5 [Reactor Scram]

B. (1) RPV shroud cracking
(2) Shut down IAW Procedure 2.1.4.1 [Rapid Shutdown]

C. (1) Displaced Jet Pump mixer
(2) Shut down IAW Procedure 2.1.5 [Reactor Scram]

D. (1) Displaced Jet Pump mixer
(2) Shut down IAW Procedure 2.1.4.1 [Rapid Shutdown]

Answer: D

Explanation:
The case presented represents diffuser displacement for jet pumps 5/6 due to hold down beam failure. Operation at 100% power on the 100% rod line results in rated core flow, 73.5 Mlbm/hr. Following the transient, indicated core flow has risen, but power has lowered significantly. An unexplained drop in reactor power is an entry condition to 2.4RXPWR. Step 4.3 requires entering Attachment 2 for an unexplained drop in power. Att. 2 addresses two potential failures, shroud cracking/separation and jet pump diffuser displacement. Attachment 3 is used to diagnose shroud cracking and Attachment 4 is used to diagnose jet pump diffuser displacement. There are some common indications used for these attachments, such as reactor power, indicated core flow, and core plate DP. Each of these indications behave similarly for either shroud cracking or jet pump diffuser displacement. Reactor power lowers, indicated core flow rises, and core plate DP lowers. Individual jet pump flows are used to discern between shroud cracking and jet pump diffuser displacement. For shroud cracking/separation, individual jet pump flows would be expected to change uniformly. In the data given, RR loop A jet pump flows have risen and RR loop B jet pump flows have lowered, indicating the failure is not common to both loops as would be expected for shroud cracking. Attachment 4 states jet pump loop flow in the intact loop will rise and in the affected loop may rise or slightly lower. RR Pump B drive flow has risen significantly, while loop B jet pump flows have lowered.

If displacement of a jet pump diffuser is confirmed, Att. 2 step 1.2.1.4 requires entry into procedure 2.1.4.1 [Rapid Shutdown] or 2.1.4 [Normal Shutdown]. Since the stem states shut down per procedure 2.1.4 would take 24 hours, procedure 2.1.4.1 is required to be used for shut down. This is because TS 3.4.2 [Jet Pumps] requires entry into Mode 3 within 12 hours for an inoperable jet pump as noted in 2.4RXPWR Att. 2.

Distracters:
Answer A part 1 is plausible because 2.4RXPWR Att. 2 addresses shroud cracking/separation, and effect of shroud cracking/separation on reactor power, core flow, and core plate DP is similar to the effect of jet pump diffuser displacement. This answer is wrong because shroud cracking would affect individual jet pump flows and Recirc Pump drive flows uniformly, but in the case presented, jet pump flows in RR loop A rise, whereas flows in RR loop B lower, indicating a jet pump pair in loop B has failed. Part 2 is plausible because some conditions require entry into procedure 2.1.5 to rapidly shutdown the plant. It is wrong because procedure 2.4RXPWR Att. 2 step 1.2.1.4 states IF confirmed displaced jet pump/mixer, THEN shut down per Procedure 2.1.4 or 2.1.4.1, and the states purpose of procedure 2.1.4.1 is that it will be used to meet LCO Required Action Completion Times when shutdown completion

time cannot be met using Procedure 2.1.4. 2.4RXPWR does not require entry into procedure 2.1.5 for this situation.

Answer B part 1 is plausible and wrong for the reasons stated for distractor A. Part 2 is correct.

Answer C part 1 is correct. Part 2 is plausible and wrong for the reasons stated for distractor A.

Technical References: Procedure 2.4RXPWR [Reactor Power Anomalies](Rev 10), procedure 2.1.4 [Normal Shutdown](Rev 169), procedure 2.1.4.1 [Rapid Shutdown](Rev 42)

References to be provided to applicants during exam: Procedure 2.4RXPWR [Reactor Power Anomalies] pages 7 and 10, ONLY (first page of Att. 3 and first page of Att. 4)

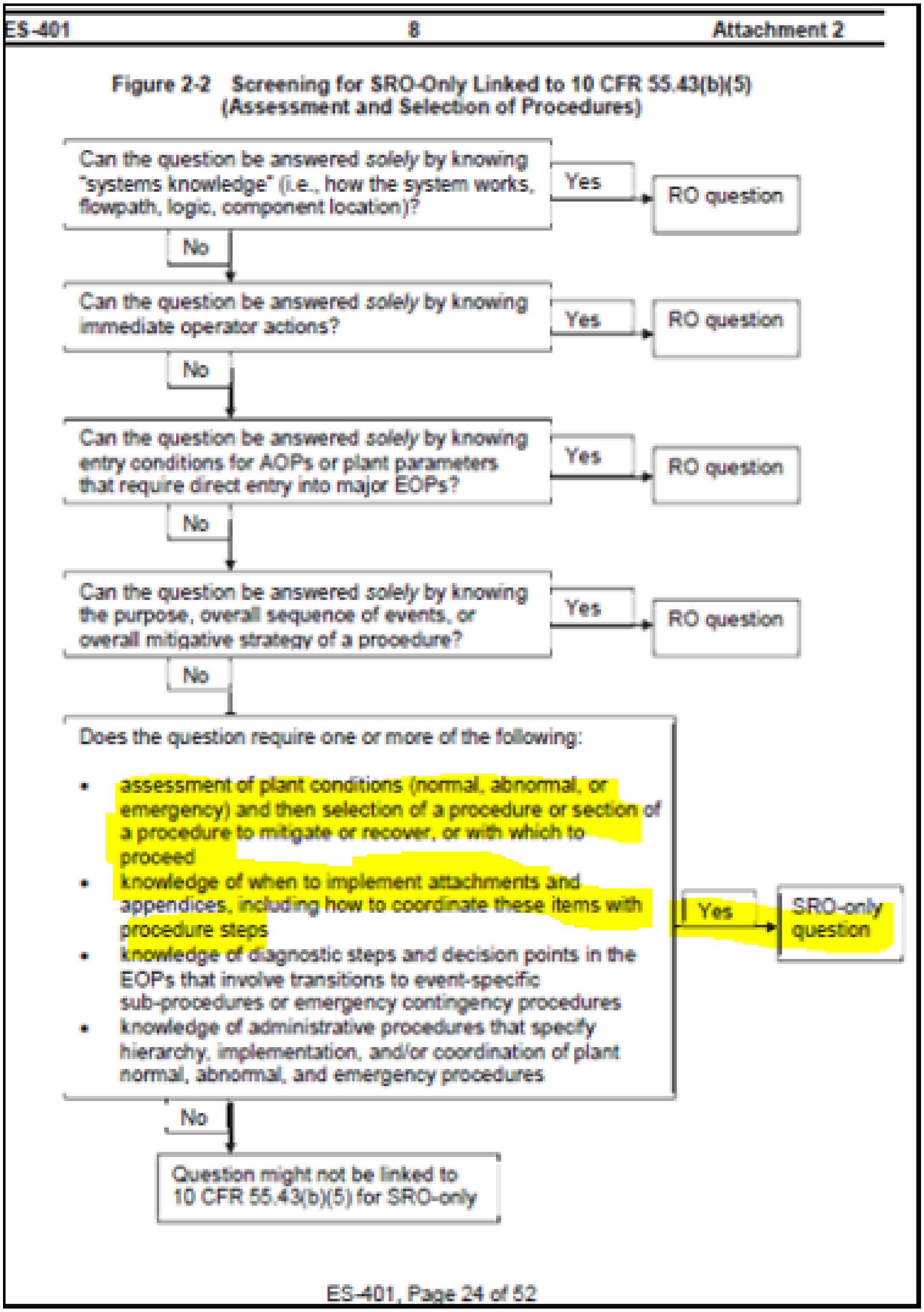
Learning Objective: INT032-01-23 EO-J, Given plant condition(s) and the applicable Abnormal/Emergency Procedure, discuss the correct subsequent actions required to mitigate the event(s)

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.43(b)(5)	
Level of Difficulty:	3	
SRO Only Justification:		

This requires evaluation of plant conditions and selection of a procedure/attachment with which to proceed. It also involves knowledge of the content of a procedure attachment versus knowledge of overall mitigative strategy or purpose.

PSA Applicability:

N/A



ES-401 8 Attachment 2
Figure 2-2 Screening for SRO-Only Linked to 10 CFR 55.43(b)(5)
(Assessment and Selection of Procedures)
Can the question be answered *solely* by knowing "systems knowledge" (i.e., how the system works, flowpath, logic, component location)?
Yes
RO question
No
Can the question be answered *solely* by knowing immediate operator actions?
Yes
RO question
No
Can the question be answered *solely* by knowing entry conditions for AOPs or plant parameters that require direct entry into major EOPs?
Yes
RO question
No
Can the question be answered *solely* by knowing the purpose, overall sequence of events, or overall mitigative strategy of a procedure?
Yes
RO question
No
Does the question require one or more of the following:
• assessment of plant conditions (normal, abnormal, or emergency) and then selection of a procedure or section of a procedure to mitigate or recover, or with which to proceed
• knowledge of when to implement attachments and appendices, including how to coordinate these items with procedure steps
• knowledge of diagnostic steps and decision points in the EOPs that involve transitions to event-specific sub-procedures or emergency contingency procedures
• knowledge of administrative procedures that specify hierarchy, implementation, and/or coordination of plant normal, abnormal, and emergency procedures
Yes
SRO-only question
No
Question might not be linked to 10 CFR 55.43(b)(5) for SRO-only
ES-401, Page 24 of 52

CNS OPERATIONS MANUAL ABNORMAL PROCEDURE 2.4RXPWR REACTOR POWER ANOMALIES	USE: CONTINUOUS QUALITY: QAPD RELATED EFFECTIVE: 8/21/19 APPROVAL: ITR-RDM OWNER: AOM-SUPPORT DEPARTMENT: OPS

1. ENTRY CONDITIONS

Scram Actions

1.1 Unexplained rise in reactor power as indicated by neutron monitoring, steam flow, and feed flow.

1.2 Uncontrolled reactor power oscillations while operating outside Stability Exclusion region of Power to Flow map.

1.3 Unexplained drop in reactor power as indicated by:

1.3.1 APRMs.

1.3.2 Reactor steam flow.

1.3.3 Reactor feed flow.

1.3.4 Main generator electrical output.

1.3.5 Reactor total core flow.

1.4 Reactor power fails to rise as expected with rise in total core flow.

2. AUTOMATIC ACTIONS

2.1 None.

3. IMMEDIATE OPERATOR ACTIONS

3.1 IF reactor power rising, THEN reduce power per Procedure 2.1.10.

3.2 IF power rise not terminated, THEN SCRAM and concurrently enter Procedure 2.1.5.

3.3 IF reactor power is undergoing significant, uncontrolled oscillations, THEN SCRAM and concurrently enter Procedure 2.1.5.

Scram Actions

4. SUBSEQUENT OPERATOR ACTIONS

4.1 Record current time and date. Time/Date: ________/__________

4.2 Contact Reactor Engineering if cause of power change is unexplained.

4.3 Perform applicable Attachment(s):

Unexplained Rise in Reactor Power	Attachment 1	Page 3
Unexplained Drop in Reactor Power	Attachment 2	Page 5
Engineering Guidance for Evaluating Core Shroud Cracking	Attachment 3	Page 7
Engineering Guidance for Evaluating Jet Pump Problems	Attachment 4	Page 10

4.4 Obtain following reviews:

- Control Room Supervisor Signature/Date: ____________ / ______
- Shift Manager Signature/Date: ____________ / ______
- AOM-Shift Signature/Date: ____________ / ______

4.5 Forward completed procedure to AOM-Support.

5. ATTACHMENTS

ATTACHMENT 2 UNEXPLAINED DROP IN REACTOR POWER

ATTACHMENT 2 UNEXPLAINED DROP IN REACTOR POWER

1. UNEXPLAINED DROP IN REACTOR POWER

1.1 IF RTP drops > 2% with no corresponding reduction in total core flow or total core flow rises, THEN perform following:®[1,2,3]

1.1.1 Obtain following data and determine if parameter changes occurred in conjunction with power drop:

1.1.1.1 Total core flow on NBI-FRDPR-95 has risen.

1.1.1.2 Core plate ΔP on NBI-FRDPR-95 lowered by 6 psid or more.

1.1.1.3 Rod line lowered by 2% or more with no control rod movement.

1.1.1.4 RR pump suction temperature on indicator or recorder (RR-TI-151A, RR-TI-151B, or RR-TR-165) has risen by 5°F or more.

1.1.1.5 RPV level initially rose and then returned to normal.

1.1.2 Compare data obtained in Step 1.1.1 to information presented in Attachment 3 (Page 7), and determine if conditions indicate shroud crack and separation, and crack location.

1.1.3 IF shroud cracking and separation is indicated or if results are unknown, THEN perform following:

1.1.3.1 Reduce power using recirculation flow per Procedure 2.1.10 until one of following met:

- Core pressure drop on NBI-FRDPR-95 ~ 6.8 psid.
- Rod line recovers to value before power drop.

1.1.3.2 Insert control rods per Procedure 10.13 to < 70% rod line.

1.2 Perform Jet Pump Operability determination per Procedure 6.LOG.601 to validate jet pump condition.

1.2.1 Compare data obtained in Step 1.2 to information presented in Attachment 4 (Page 10).

1.2.1.1 IF loose jet pump mixer, THEN determine if shutdown per Procedure 2.1.4 necessary.

ATTACHMENT 4 ENGINEERING GUIDANCE FOR EVALUATING JET PUMP PROBLEMS

ATTACHMENT 4 ENGINEERING GUIDANCE FOR EVALUATING JET PUMP PROBLEMS

PARAMETER	PROBLEM LOCATION			
	DISPLACED JET PUMP MIXER	LOOSE JET PUMP MIXER	PLUGGED JET PUMP/RISER	INSTRUMENT LINE FAILURE
REACTOR POWER	Drop due to loss in core flow.	No to small drop.	See Displaced/ Loose indication column.	No change.
INDICATED CORE FLOW	Rise due to addition of reverse JP flow.	No to small rise.	See Displaced/ Loose indication column.	Rise.
JET PUMP FLOW RELATIONSHIP D/P	Sound loop unchanged. Affected loop significant changes.	Sound loop unchanged. Affected loop skewed pattern changes.	See Displaced/ Loose indication column.	Sound loop no change. Affected loop changes effected JP.
JET PUMP LOOP FLOW	Sound loop ≥ 5%. Affected loop rise or slight lower. (Reverse flow added by flow measurement system.)	N/A	See Displaced indication column.	Affected loop rise. Sound loop no change.
RR PUMP FLOW	Affected loop flow rise by ≥ 10% or more.	N/A	See Displaced indication column.	No change.
CORE PLATE ΔP	Lower and correspond to core flow lowering.	No change.	See Displaced/ Loose indication column.	No change.
CORE FLOW - SQUARE ROOT CORE PLATE D/P	Deviate ≥ 5% from normal.	No change.	See Displaced/ Loose indication column.	N/A
RR PUMP FLOW/SPEED RATIO	> 10% of normal.	Affected loop 2% to 4% above normal.	Lower than normal.	No change.

ATTACHMENT 3 ENGINEERING GUIDANCE FOR EVALUATING CORE SHROUD CRACKING

ATTACHMENT 3 ENGINEERING GUIDANCE FOR EVALUATING CORE SHROUD CRACKING

PARAMETER	CRACK LOCATION		
	ABOVE TOP GUIDE	BETWEEN TOP GUIDE AND CORE PLATE	BELOW CORE PLATE
REACTOR POWER	Abrupt drop could exceed 20% rated power.	Abrupt drop up to 6% rated power.	Drop up to 10% rated power.
INDICATED CORE FLOW	May rise.	Rises or remains constant.	May not change significantly.
ROD LINE	Bigger drop with rising core flow.	Bigger drop with rising core flow.	Bigger drop with rising core flow.
CORE INLET SUBCOOLING	Lowers.	N/A	N/A
RR SUCTION TEMP.	*Rise above normal for existing power level.	No significant rise. Rises as expected for power drop.	N/A
CORE PLATE ΔP	N/A	N/A	Lowers by 1/3 of normal.
RR FLOW TO TOTAL CORE FLOW RATIO	N/A	N/A	Abnormal relationships of RR pump flow to core flow and core power to core flow.

* If crack on one side of shroud only, RR Suction Temp. in loop nearest crack separation will rise above other RR loop.

Additional Symptoms:

1. If crack separation develops abruptly at steady state conditions, downcomer water level rise will be noticeable on Control Room level instruments. Level rise could be significant enough to cause turbine trip.
2. If crack separation develops gradually within capacity of level control system, a water level change is noticeable until level control system returns level to normal.
3. If crack separation develops abruptly at rated conditions, LPRM tubes may become disengaged from top guide. LPRMs dropping lower in core will indicate higher flux.
4. Refer to rest of this attachment for further explanation of parameter changes.

1.2.1.2 IF plugged jet pump/riser, THEN perform following:

a. IF greater than or equal to one jet pump completely plugged, THEN shut down per Procedure 2.1.4.

b. IF partial plugging occurs, THEN determine if shutdown per Procedure 2.1.4 necessary.

1.2.1.3 IF instrument line failure, THEN use alternate flow indication of other jet pump on associated riser.

NOTE – LCO 3.4.2 requires to be in MODE 3 in 12 hours for an inoperable jet pump.

1.2.1.4 IF confirmed displaced jet pump/mixer, THEN shut down per Procedure 2.1.4 or 2.1.4.1.

1.3 IF core shroud cracking and separation confirmed or if reduction in reactor power cannot be explained, THEN perform normal shutdown per Procedure 2.1.4.

CNS OPERATIONS MANUAL GENERAL OPERATING PROCEDURE 2.1.4.1 RAPID SHUTDOWN	USE: CONTINUOUS℗[4] QUALITY: QAPD RELATED EFFECTIVE: 1/2/19 APPROVAL: ITR-RDM OWNER: OSG SUPV DEPARTMENT: OPS

CONDITIONALLY RISK SIGNIFICANT PROCEDURE ℗[1]

REVISION VERIFICATION: (initial use + every 7 days)

REV.	DATE	CHANGES
41	4/12/18	Edited references to Procedure 2.2.18. Procedure has been deleted and replaced by six different 2.2.18 series procedures.
42	1/2/19	EC 18-055.

1. PURPOSE

1.1 This procedure provides instructions for Operations personnel to perform a rapid shutdown from MODE 1. The procedure will be used to meet LCO Required Action Completion Times when shutdown completion time cannot be met using Procedure 2.1.4.

Examination Outline Cross-Reference	Level	SRO
295028 (EPE 5) High Drywell Temperature (Mark I and Mark II only) / 5 2.2.12 Knowledge of surveillance procedures.	Tier#	1
	Group#	1
	K/A #	295028 G2.2.12
	Rating	4.1
	Revision	0
Revision Statement:		

Question 83

The plant is at 100% power with the following conditions:

- Drywell temperature is 140°F, rising slowly due to leak
- Four DW FCUs are operating
- 2.4PC has been entered
- Drywell venting is in progress AND drywell pressure is 0.3 psig, steady

SR 3.6.1.5.1 to verify drywell average air temperature within limits has a specified frequency interval of 24 hours AND was last performed **20 hours ago**.

(1) IAW TS SR rules of application, what is the MAXIMUM time remaining until SR 3.6.1.5.1 must be completed again to maintain the surveillance current?

AND

(2) If drywell temperature rises above the EOP-3A entry condition, which is the preferred source for determining average drywell temperature?

A. (1) 4 hours
(2) PMIS Point SPDS0202 [AVE DW TEMP (DYNAMIC CALC)]

B. (1) 4 hours
(2) Procedure 5.8.10 [Average Drywell Temperature Calculation]

C. (1) 10 hours
(2) PMIS Point SPDS0202 [AVE DW TEMP (DYNAMIC CALC)]

D. (1) 10 hours
(2) Procedure 5.8.10 [Average Drywell Temperature Calculation]

Answer: C

Explanation:
In Mode 1, drywell average temperature is required to be verified ≤150°F IAW SR 3.6.1.5.1 IAW the Surveillance Frequency Control Program. The frequency interval specified by the SFCP for SR 3.6.1.5.1 is 24 hours. SR 3.0.2 establishes the requirements for meeting the specified Frequency for Surveillances. SR 3.0.2 permits a 25% extension of the interval specified in the Frequency. 25% of 24 hours is 6 hours. Therefore, one surveillance interval must not exceed 30 hours. Since it has been 20 hours since SR 3.6.1.5.1 was last completed, it must be completed again within 10 hours to maintain the surveillance current.

If a leak in the drywell is indicated and four DW FCUs are operating, Procedure 2.4PC step 4.10.8.1 requires using PMIS Point SPDS0202. If PMIS Point SPDS0202 is other than healthy or if less than four DW FCUs are operating, 2.4PC requires use of alternate methods to determine drywell average air temperature.

Distracters:
Answer A part 1 is plausible because the stated surveillance frequency interval is 24 hours, and in some cases, SR 2.0.2 does not allow an extension to a specified interval. For example, if the specified interval was “once per” basis the 25% extension does not apply to the initial portion of a periodic Completion Time that requires performance on a "once per ... " basis. The extension also does not apply for some requirements where an exclusion is explicitly stated, such as for the Containment Leakage Rate Testing Program. This answer is wrong because the 25% extension does apply in this case, so the maximum frequency interval is 30 hours. 10 hours remain until the current interval expires. Part 2 is correct.

Answer B part 1 is plausible for the same reasons stated for distractor A. Part 2 is plausible because various methods for determining drywell average air temperature exist based on plant conditions. Also, EOP-3A step DW/T-1 states Monitor average drywell temperature, EOP 5.8.10, and control below 150°F using available drywell cooling. The examinee that believes the reference to procedure 5.8.10 is an unqualified direction to use that method and who does not have knowledge of the prerequisite or methodology for that procedure may choose this answer. It is wrong because use of 5.8.10 is predicated on unavailability of SPDS. In this case, SPDS is available and use of PMIS Point SPDS0202 is much less cumbersome than manual calculation per 5.8.10 and yields a more accurate result; therefore, use of PMIS Point SPDS0202 is preferred and is specified by 2.4PC.

Answer D part 1 is correct. Part 2 is plausible and wrong for the reasons given for distractor B.

Technical References: Procedure 2.4PC [Primary Containment Control](Rev 20), Procedure 5.8.10 [Average Drywell Temperature Calculation](Rev 8), Procedure 6.PC.604 [Average Drywell Temperature Manual Determination](Rev 6), EOP-3A

[Primary Containment Control](Rev 17), TS 3.6.1.5 [Drywell Air Temperature], TS SR 3.0.2 [SR Applicability] Bases		
References to be provided to applicants during exam: none		
Learning Objective: INT007-05-01 EO-10, Apply the rules for Frequency to determine when a periodic action must be performed.		
Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.43(b)(2)(10)	
Level of Difficulty:	3	
SRO Only Justification:		
Part 1 requires application of generic LCO requirement SR 2.0.2. Part 2 requires evaluation of plant conditions and selection of a procedure with which to proceed.		
PSA Applicability:		
Top 10 Risk Significant Systems – Primary Containment		

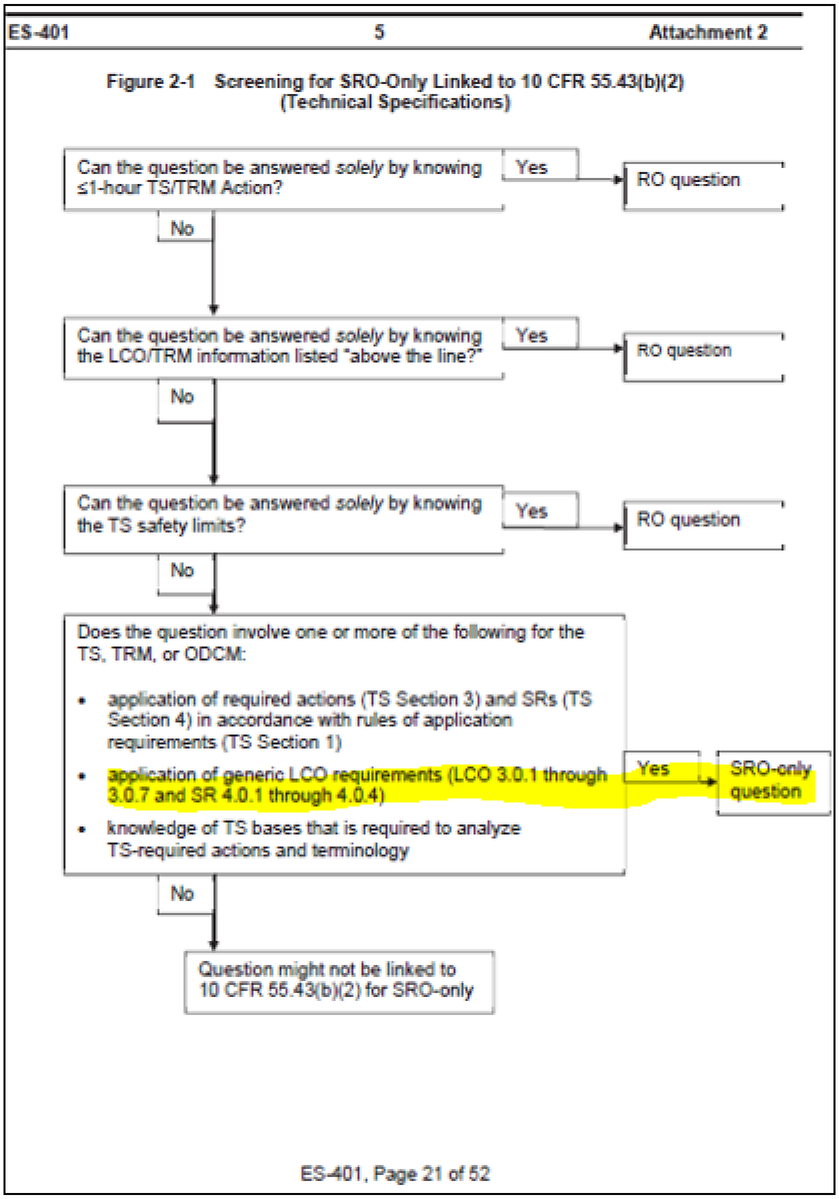
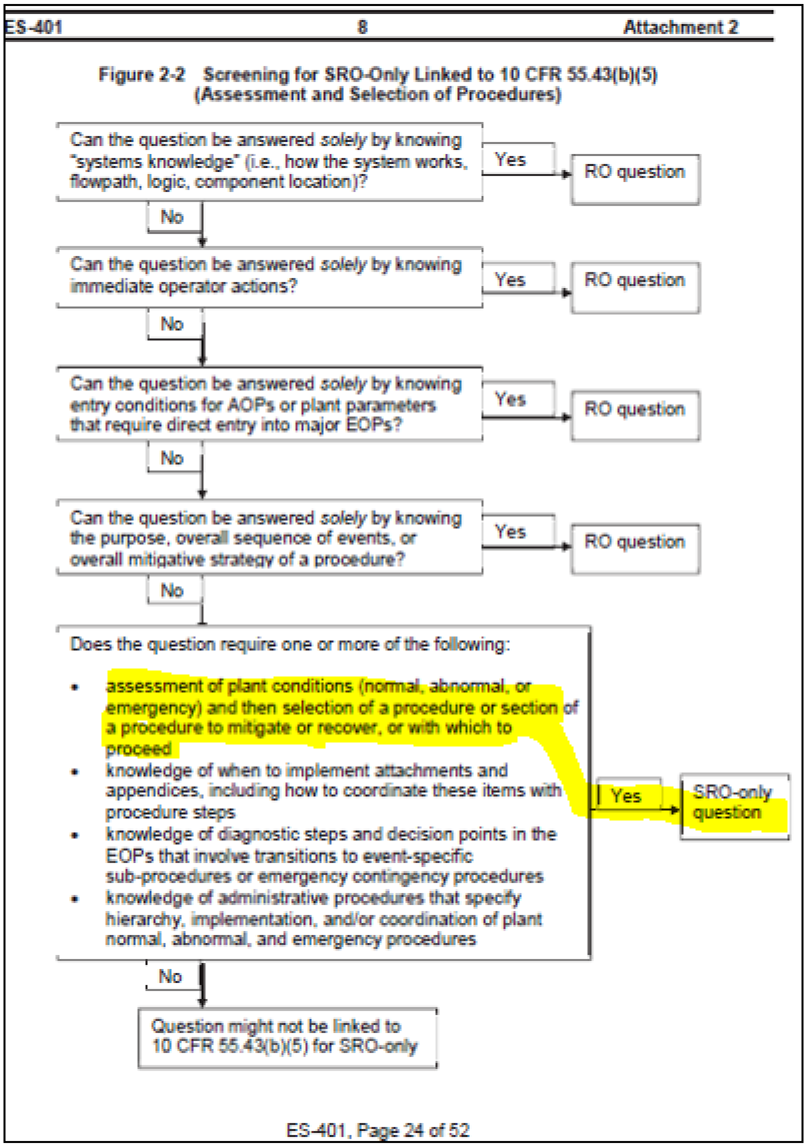


Figure 2-1 Screening for SRO-Only Linked to 10 CFR 55.43(b)(2)
(Technical Specifications)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Attachment 2
Figure 2-2 Screening for SRO-Only Linked to 10 CFR 55.43(b)(5) (Assessment and Selection of Procedures)
Can the question be answered solely by knowing "systems knowledge" (i.e., how the system works, flowpath, logic, component location)?
Yes
RO question
No
Can the question be answered solely by knowing immediate operator actions?
Yes
RO question
No
Can the question be answered solely by knowing entry conditions for AOPs or plant parameters that require direct entry into major EOPs?
Yes
RO question
No
Can the question be answered solely by knowing the purpose, overall sequence of events, or overall mitigative strategy of a procedure?
Yes
RO question
No
Does the question require one or more of the following:
• assessment of plant conditions (normal, abnormal, or emergency) and then selection of a procedure or section of a procedure to mitigate or recover, or with which to proceed
• knowledge of when to implement attachments and appendices, including how to coordinate these items with procedure steps
• knowledge of diagnostic steps and decision points in the EOPs that involve transitions to event-specific sub-procedures or emergency contingency procedures
• knowledge of administrative procedures that specify hierarchy, implementation, and/or coordination of plant normal, abnormal, and emergency procedures
Yes
SRO-only question
No
Question might not be linked to 10 CFR 55.43(b)(5) for SRO-only
ES-401, Page 24 of 52

Drywell Air Temperature
3.6.1.5

3.6 CONTAINMENT SYSTEMS

3.6.1.5 Drywell Air Temperature

LCO 3.6.1.5 Drywell average air temperature shall be ≤ 150°F.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Drywell average air temperature not within limit.	A.1	Restore drywell average air temperature to within limit.	8 hours
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	12 hours
	AND		
	B.2	Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.5.1	Verify drywell average air temperature is within limit.	In accordance with the Surveillance Frequency Control Program

Cooper 3.6-17 Amendment No. 258

INFORMATION ONLY

Surveillance Frequency Control Program
List of Surveillance Frequencies and Bases

Surv. Req.	Description	Freq.	Frequency Bases	STIC Eval. #
3.6.1.4	**Drywell Pressure**			
3.6.1.4.1	**Verify drywell pressure is within limit.**	12 hours	The Frequency of this SR was developed, based on operating experience related to trending of drywell pressure variations during the applicable MODES. Furthermore, the Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal drywell pressure condition.	None.
3.6.1.5	**Drywell Air Temperature**			
3.6.1.5.1	**Verify drywell average air temperature is within limit.**	24 hours	The Frequency of the SR was developed based on operating experience related to drywell average air temperature variations and temperature instrument drift during the applicable MODES and the low probability of a DBA occurring between surveillances. Furthermore, the Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal drywell air temperature condition.	None.

SR 3.0.2

SR 3.0.2 establishes the requirements for meeting the specified Frequency for Surveillances and any Required Action with a Completion Time that requires the periodic performance of the Required Action on a "once per..." interval.

SR 3.0.2 permits a 25% extension of the interval specified in the Frequency. This extension facilitates Surveillance scheduling and considers plant operating conditions that may not be suitable for conducting the Surveillance (e.g., transient conditions or other ongoing Surveillance or maintenance activities).

Cooper B 3.0-14 09/18/09

SR Applicability
B 3.0

BASES

SR 3.0.2 (continued)

When a Section 5.5, "Programs and Manuals," Specification states that the provisions of SR 3.0.2 are applicable, a 25% extension of the testing interval, whether stated in the Specification or incorporated by reference, is permitted.

The 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the SRs. The exceptions to SR 3.0.2 are those Surveillances for which the 25% extension of the interval specified in the Frequency does not apply. These exceptions are stated in the individual Specifications. The requirements of regulations take precedence over the TS. Examples of where SR 3.0.2 does not apply are the Containment Leakage Rate Testing Program required by 10 CFR 50, Appendix J, and the inservice testing of pumps and valves in accordance with applicable American Society of Mechanical Engineers Operation and Maintenance Code, as required by 10 CFR 50.55a. These programs establish testing requirements and Frequencies in accordance with the requirements of the regulations. The TS cannot in and of themselves extend a test interval specified in the regulations, directly or by reference.

As stated in SR 3.0.2, the 25% extension also does not apply to the initial portion of a periodic Completion Time that requires performance on a "once per..." basis. The 25% extension applies to each performance after the initial performance. The initial performance of the Required Action, whether it is a particular Surveillance or some other remedial action, is considered a single action with a single Completion Time. One reason for

4.10.8 Determine drywell temperature from one of following temperatures:

4.10.8.1 IF four Drywell Fan Coil Units in operation, THEN use PMIS Point SPDS0202.

a. IF PMIS Point SPDS0202 quality code is other than healthy, THEN perform following:

1. IF plant conditions allow completion of Procedure 6.PC 604, THEN determine average drywell temperature per Procedure 6.PC.604.

4.10.8.2 IF either of below conditions exist, THEN use PMIS Point SPDS0104.

- Three or less Drywell Fan Coil Units are in operation.
- Procedure 6.PC 604 cannot be performed.

a. IF PMIS Point SPDS0104 quality code is other than healthy, THEN use PMIS Point SPDS0110.

4.10.9 Lower drywell temperature, as necessary, by performing following:

4.10.9.1 Lower reactor power per Procedure 2.1.10 to maintain average drywell temperature < 148°F.

4.10.9.2 IF reactor has been shutdown, THEN initiate a reactor cooldown at maximum allowable rate.

4.10.9.3 As plant conditions dictate, de-inert containment or purge the drywell per Procedure 2.2.60.

4.10.10 IF drywell average air temperature cannot be maintained ≤ 150°F, THEN enter applicable Conditions and Required Actions of LCO 3.6.1.5.

4.10.11 Monitor for rise in Primary Containment relative humidity using Attachment 1 (Page 4).

4.11 Obtain following reviews:

- Control Room Supervisor Signature/Date: ______________ / ______
- Shift Manager Signature/Date: ______________ / ______
- AOM-Shift Signature/Date: ______________ / ______

4.12 Forward completed procedure to AOM-Support.

5. ATTACHMENTS

CNS OPERATIONS MANUAL EMERGENCY OPERATING PROCEDURE 5.8.10 AVERAGE DRYWELL TEMPERATURE CALCULATION	USE: REFERENCE QUALITY: QAPD RELATED EFFECTIVE: 7/18/13 APPROVAL: ITR-RDM OWNER: OSG SUPV DEPARTMENT: OPS

1. PURPOSE

1.1 This procedure provides a means to calculate average drywell temperature, as required, by EOPs or SAGs, when SPDS is not available.

2. REQUIREMENTS

2.1 EOPs or SAGs require Operator to determine average drywell temperature, and SPDS is unable to provide average drywell temperature for following:

2.1.1 EOP 3A, PRIMARY CONTAINMENT CONTROL, entry condition of average drywell temperature above 150°F.

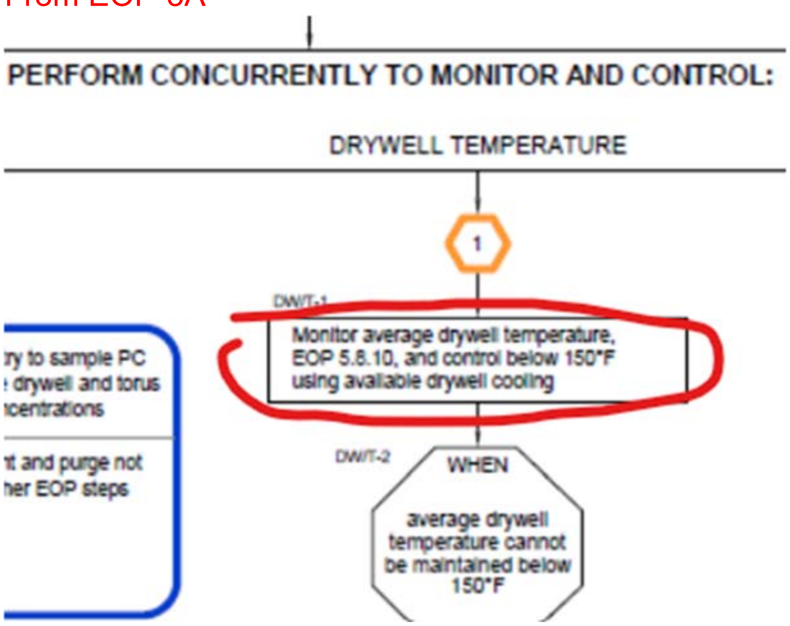
2.1.2 EOP Steps DW/T-1 through DW/T-5.

2.1.3 Drywell Spray Initiation Limit, Graph 9.

2.1.4 SAG 1, Steps DW/T-1 and DW/T-2.

3. AVERAGE DRYWELL TEMPERATURE CALCULATION

From EOP-3A



Examination Outline Cross-Reference	Level	SRO
209001 (SF2, SF4 LPCS) Low-Pressure Core Spray Ability to (a) predict the impacts of the following on the LOW PRESSURE CORE SPRAY SYSTEM; and (b) based on those predictions, use procedures to correct, control, or mitigate the consequences of those abnormal conditions or operations: A2.01 Pump trips	Tier#	2
	Group#	1
	K/A #	209001 A2.01
	Rating	3.4
	Revision	0
Revision Statement:		

Question 84

The following conditions exist during a LOCA: EOP-1A is being executed

- Reactor water level -200 inches CFZ, steady
- Reactor pressure 47 psig, slowly lowering
- Drywell pressure 23 psig, slowly lowering
- Core Spray A flow 4800 gpm
- Core Spray B flow 2500 gpm
- The only available injection systems are Core Spray A and B

Then, Core Spray Pump A trips on overcurrent.

Which action is required NEXT?

Transition to …

A. SAG 1

B. SAG 2

C. EOP-1B

D. EOP-2A

Answer: A
Explanation:

For the initial conditions, operation is holding at EOP-1A step RC/L-15. With reactor level below -183 inches and CS systems injecting, adequate core cooling is being provided by CS Pump A, since its flow is above 4750 gpm. When CS Pump A trips, reactor level, which was only stable with both CS pumps injecting, will lower. CS Pump B flow is below 4750 gpm, so it will not alone provide sufficient heat removal for adequate core cooling. EOP-1A step RC/L-15, 16, 17, and18 are now required to be executed, since injection is already maximized and level is below -183 inches and now will be lowering. Step RC/L-18 requires exiting all EOP flowcharts and entering SAG 1.

Alternate level control strategy was revised in 2019. EOP-1A and EOP-2A were significantly revised due to the addition of new EOP-1B.

Distracters:

Answer B is plausible because entry into SAGs is required. Adequate injection has been lost, and SAG 2 contains instructions for use of injection systems for RPV and Containment flooding. The examinee who does not recall how SAGs are constructed and which SAG is specified by EOP-1A step RC/L-18 may choose this answer. It is wrong because SAG 1 must be entered directly from EOPs, because it contains the logic for entry into the appropriate flowchart of SAG 2, based on conditions such as whether the core has breached the RPV and whether the containment is in jeopardy.

Answer C is plausible because EOP-1A step RC/L-2 2nd override directs entering EOP-1B if it is anticipated that available injection systems alone cannot assure adequate core cooling. This answer is wrong because step RC/L-2 2nd override is intended to be an anticipatory step where adequate core cooling exists but is expected to be lost in the future. EOP-1B coordinates RPV water level and RPV pressure control actions to prolong availability of steam-driven injection systems and optimize the transfer to motor-driven systems. In this case, steam driven systems are not available and control has already been transferred to motor driven systems. Adequate core cooling has already been lost due to level <-183 inches with injection flow from CS B. EOP-1B directs stem cooling down to -195 inches. Level is already below -195 inches and cannot be restored >-183 inches, so entry into SAG 1 is required now.

Answer D is plausible because Emergency Depressurization IAW EOP-2A is directed by EOP-1A step RC/L-10 due to reactor water level below -158 inches, and an examinee may reason that further depressurization may not recognize the reactor is already depressurized, since reactor pressure is <50psig above DW pressure, and may believe ED will result in adequate injection flow rate from CS B. The examinee who does not recall the layout and strategy of EOP-1A may choose this answer. It is wrong because for the initial conditions given, specifically reactor level <-183 inches and level not rising, Emergency depressurization would have already been required. Reactor pressure <73 psig indicates depressurization is complete.

Technical References: EOP-1A [RPV Control](Rev 22), EOP-1B [Alternate Level/Pressure Control](Rev 2), EOP-2A [Emergency RPV Depressurization](Rev 20), SAG 1 [RPV, Containment and Radioactivity Release Control](Rev 11), PSTG (AMP-TBD00 Technical Basis)(Rev 10)		
References to be provided to applicants during exam: none		
Learning Objective: INT008-06-05 EO-10, Given plant conditions and EOP flowchart 1A, RPV CONTROL, determine required actions.		
Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.43(b)(5)	
Level of Difficulty:	3	
SRO Only Justification:		
This requires evaluation of plant conditions and selection of a procedure with which to proceed.		
PSA Applicability:		
N/A		

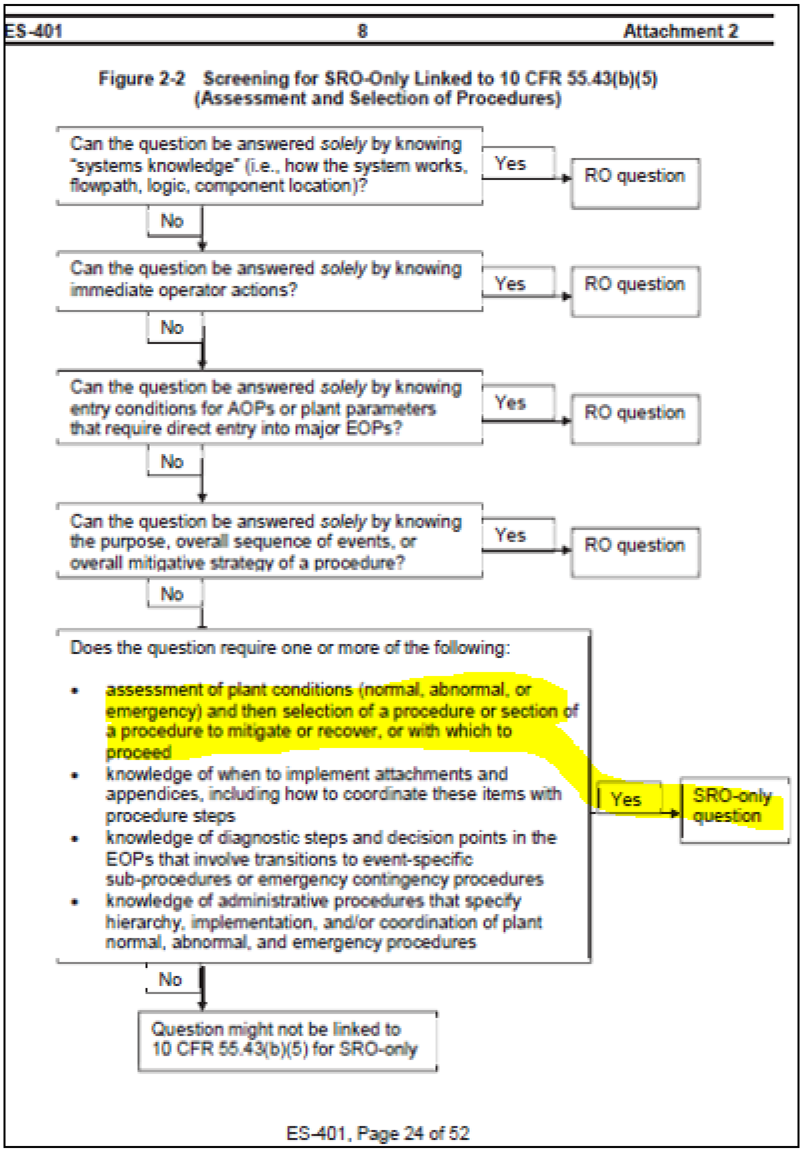


Figure 2-2 Screening for SRO-Only Linked to 10 CFR 55.43(b)(5) (Assessment and Selection of Procedures)

Can the question be answered *solely* by knowing "systems knowledge" (i.e., how the system works, flowpath, logic, component location)?
Yes → RO question
No ↓

Can the question be answered *solely* by knowing immediate operator actions?
Yes → RO question
No ↓

Can the question be answered *solely* by knowing entry conditions for AOPs or plant parameters that require direct entry into major EOPs?
Yes → RO question
No ↓

Can the question be answered *solely* by knowing the purpose, overall sequence of events, or overall mitigative strategy of a procedure?
Yes → RO question
No ↓

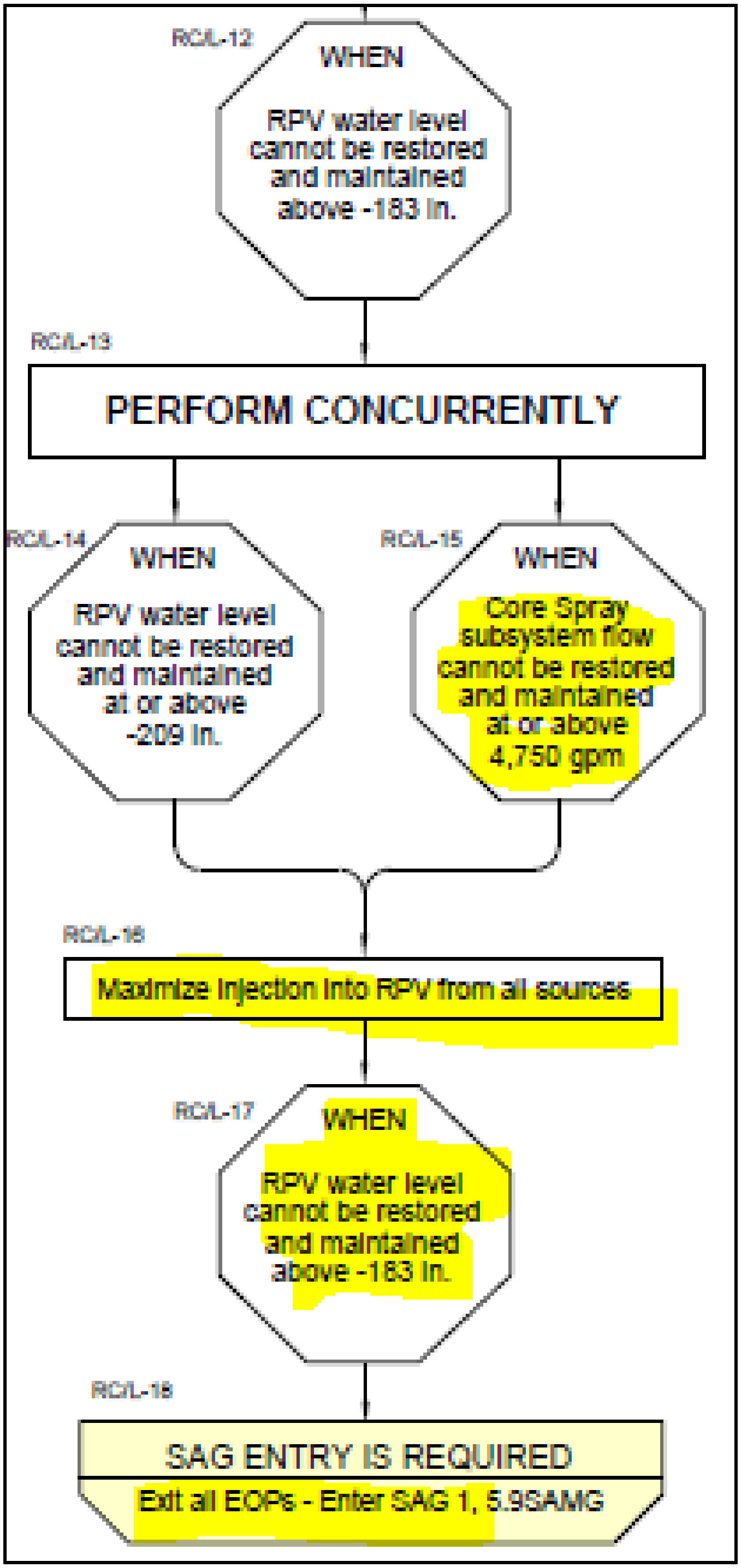
Does the question require one or more of the following:

- assessment of plant conditions (normal, abnormal, or emergency) and then selection of a procedure or section of a procedure to mitigate or recover, or with which to proceed
- knowledge of when to implement attachments and appendices, including how to coordinate these items with procedure steps
- knowledge of diagnostic steps and decision points in the EOPs that involve transitions to event-specific sub-procedures or emergency contingency procedures
- knowledge of administrative procedures that specify hierarchy, implementation, and/or coordination of plant normal, abnormal, and emergency procedures

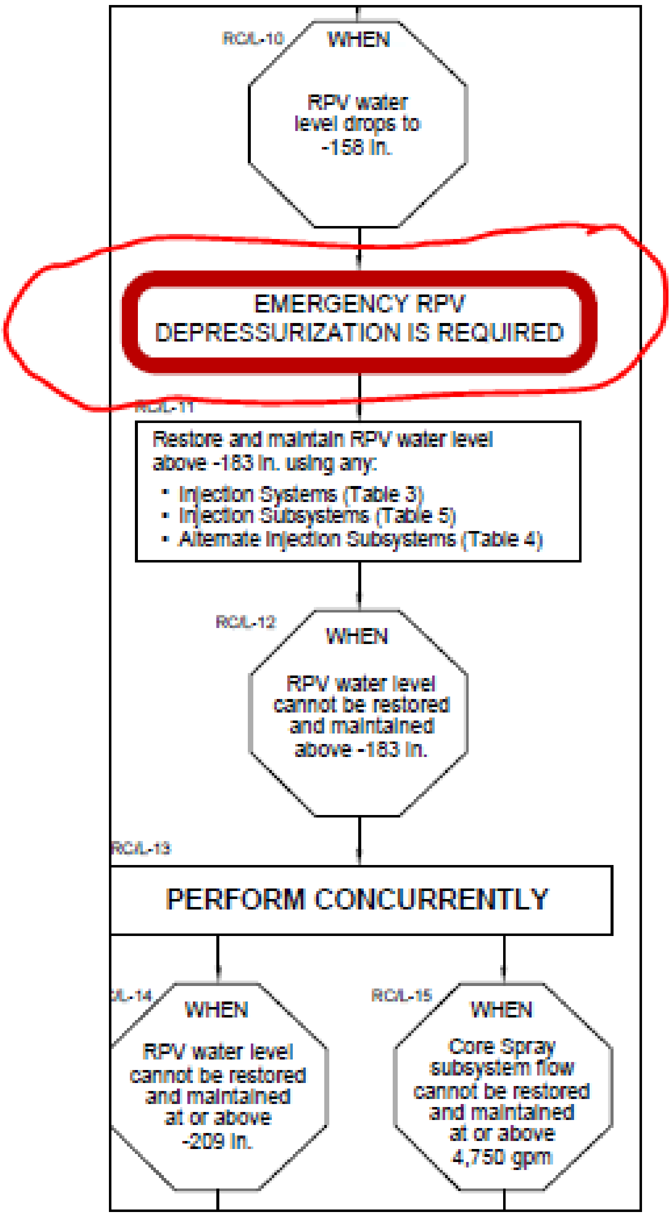
Yes → SRO-only question
No ↓

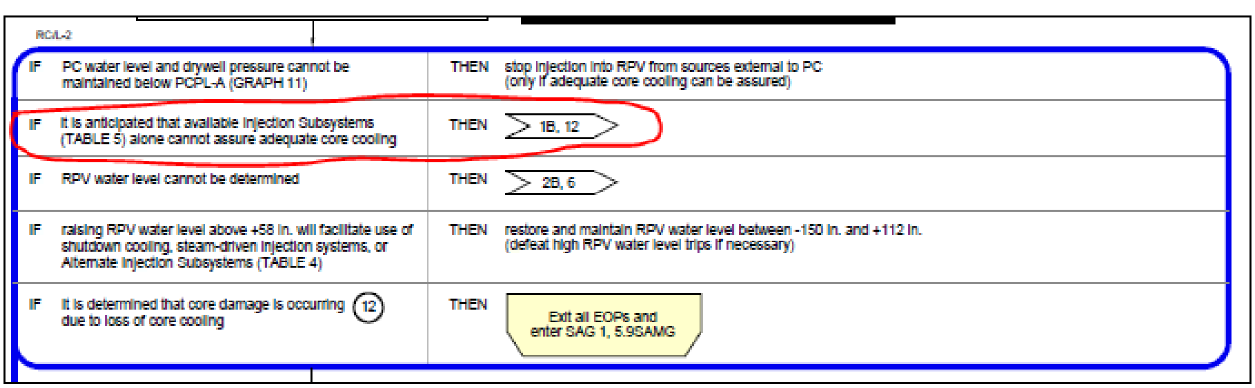
Question might not be linked to 10 CFR 55.43(b)(5) for SRO-only

From EOP-1A [RPV Control]



From EOP-1A [RPV Control]


RC/L-10
WHEN
RPV water level drops to -158 in.
EMERGENCY RPV DEPRESSURIZATION IS REQUIRED
RC/L-11
Restore and maintain RPV water level above -183 in. using any:
• Injection Systems (Table 3)
• Injection Subsystems (Table 5)
• Alternate Injection Subsystems (Table 4)
RC/L-12
WHEN
RPV water level cannot be restored and maintained above -183 in.
RC/L-13
PERFORM CONCURRENTLY
L-14
WHEN
RPV water level cannot be restored and maintained at or above -209 in.
RC/L-15
WHEN
Core Spray subsystem flow cannot be restored and maintained at or above 4,750 gpm


RC/L-2
IF PC water level and drywell pressure cannot be maintained below PCPL-A (GRAPH 11)
THEN stop injection into RPV from sources external to PC (only if adequate core cooling can be assured)
IF it is anticipated that available Injection Subsystems (TABLE 5) alone cannot assure adequate core cooling
THEN 1B, 12
IF RPV water level cannot be determined
THEN 2B, 6
IF raising RPV water level above +58 in. will facilitate use of shutdown cooling, steam-driven injection systems, or Alternate Injection Subsystems (TABLE 4)
THEN restore and maintain RPV water level between -150 in. and +112 in. (defeat high RPV water level trips if necessary)
IF it is determined that core damage is occurring due to loss of core cooling 12
THEN Exit all EOPs and enter SAG 1, 5.9SAMG

PSTG/SATG Step (First override before Step RC/L-2)

> If while executing the following steps:
>
> - ...
> - ...
> - It is anticipated that available Injection Subsystems (Table L-6) alone cannot assure adequate core cooling and it has been determined that the reactor will remain shutdown under all conditions without boron (**TSG-3.10**), enter Contingency #1.
> -

Discussion

Each Injection Subsystem (Table L-6) is a high capacity motor-driven system loop independently capable of supplying high quality makeup water to the RPV. The Injection Subsystems are a subset of the Preferred Injection Systems (Table L-1), which include both those used to control RPV water level during normal plant operations at power and those categorized as emergency makeup.

The maximum RPV pressure at which Injection Subsystems can inject requires a relatively low RPV pressure. If the flow provided by Injection Subsystems will not provide adequate core cooling, available steam-driven systems and low-capacity motordriven systems such as CRD, SLC and Alternate Injection Subsystems must be relied on until additional systems become available.

Adequate core cooling can be established by core submergence, spray cooling, or steam cooling, as defined and discussed in Section 3 of this appendix. Irrespective of the current RPV pressure and injection flowrate, if it is determined that one or more Injection Subsystems are capable of assuring adequate core cooling by any of these methods, transfer to Contingency #1 is not required; a Subsystem may be considered "available" even if not currently injecting. The RPV pressure control subsection and related contingencies provide guidance on controlling RPV pressure to support core cooling strategies and, when appropriate, depressurizing the RPV to permit injection from low pressure sources.

If adequate core cooling cannot be assured with available Injection Subsystems, Contingency #1 is entered. Contingency #1 coordinates RPV water level and RPV pressure control actions to prolong availability of steam-driven injection systems and optimize the transfer to motor-driven systems. If RPV pressure is reduced prematurely, before a motor-driven injection source is available, steam-driven systems could be lost and adequate core cooling threatened. If low-capacity motor-driven systems are the only sources of injection, RPV pressure must be lowered to below the associated maximum injection pressures to permit injection and maintain adequate core cooling. If no source of RPV injection is available, RPV inventory should be conserved to prolong core cooling until an injection source is returned to service.

Contingency #1 is entered only if the reactor will remain shutdown under all conditions without boron. ATWS strategies for controlling RPV water level, RPV pressure, and reactor power are likely to conflict with the Contingency #1 strategies.

Criteria used to demonstrate that the reactor will remain shutdown under all conditions without boron include determining:

- Control rod position is within the Maximum Subcritical Banked Withdrawal Position (MSBWP). The MSBWP is the greatest banked rod position at which the reactor will remain shutdown under all conditions. Refer to Section 18 of this appendix for a detailed discussion of the MSBWP.
- The existence of the core design basis shutdown margin with the single strongest control rod full-out and all other control rods full-in
- Compliance with Technical Specification requirements governing control rod position and the allowable number of inoperable control rods.

In some cases, the control room operating crew may be able to make the determination themselves. In most cases, however, it is expected that the determination will be made by a reactor engineer or other member of the technical support staff. The referenced TSG section provides additional guidance on performing the evaluation. Note that the instruction requires a positive determination, not only that the reactor *is* shutdown, but that it will *remain* shutdown, without reliance upon boron, under worst-case cold shutdown conditions. The phrase "without boron" does not imply that the condition cannot be met if boron has been injected, but that credit cannot be taken for the negative reactivity contributed by the boron. Control rod insertion alone must provide the necessary shutdown margin.

Examination Outline Cross-Reference	Level	SRO
295015 (APE 15) Incomplete Scram / 1 Ability to determine and/or interpret the following as they apply to INCOMPLETE SCRAM: AA2.02 Control rod position	Tier#	1
	Group#	2
	K/A #	295015
	Rating	4.2
	Revision	0
Revision Statement:		

Question 85

The plant is at 50% power late in the operating cycle when loss of both RPS buses occurs.

The following control rod positions result:

- 24 control rods are at position 00
- One rod remains at position 48
- All other control rods are at position 02

According to EOP Technical Bases (PSTG)…

(1) Is Maximum Subcritical Banked Rod Withdrawal Position (MSBWP) met for shutdown margin?

AND

(2) Is transition to EOP-6A required?

A. (1) no
(2) no

B. (1) no
(2) yes

C. (1) yes
(2) no

D. (1) yes
(2) yes

Answer: B
Explanation:

The Maximum Subcritical Banked Withdrawal Position (MSBWP) is the greatest banked rod position at which the reactor will remain shutdown under all conditions. At CNS, the MSBWP is determined in NEDC 97-089 and is assigned the value of position 02. Since all control rods are not at or beyond position 02, MSBWP is not met for shutdown margin.

EOP-1A step RC-3 asks Has it been determined that reactor will remain shutdown under all conditions without boron. If answered NO, transition to EOP-6A and 7A is required.

Criteria used to demonstrate that the reactor will remain shutdown under all conditions without boron include determining:

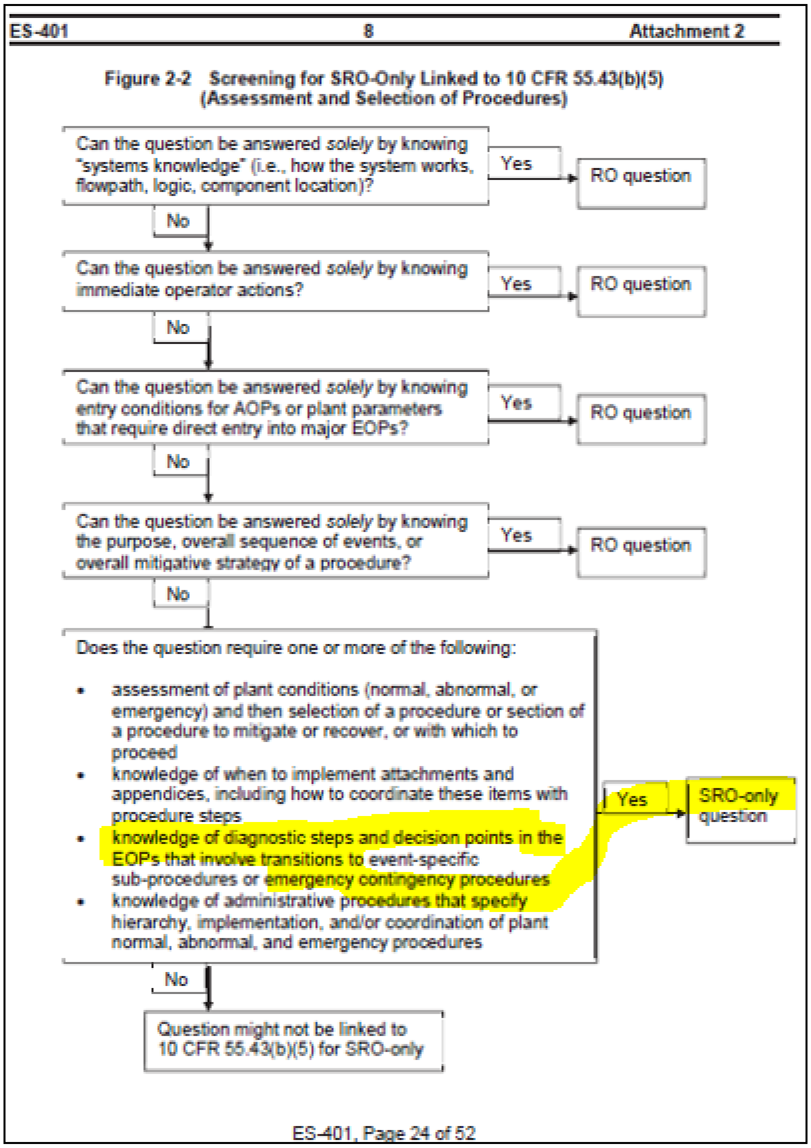
- Control rod position is within the Maximum Subcritical Banked Withdrawal Position (MSBWP). The MSBWP is the greatest banked rod position at which the reactor will remain shutdown under all conditions.
- The existence of the core design basis shutdown margin with the single strongest control rod full-out and all other control rods full-in
- Compliance with Technical Specification requirements governing control rod position and the allowable number of inoperable control rods.

In some cases, the control room operating crew may be able to make the determination that the reactor will remain shutdown without boron themselves. In most cases, however, it is expected that the determination will be made by a reactor engineer or other member of the technical support staff. Therefore, transition to EOP-6A is required.

Distracters:
Answer A part 1 is correct. Part 2 is plausible because all control rods except for one are at or beyond position 02, and shutdown margin accommodates the highest worth control rod being at position 48. An examinee may believe the requirement assumes both MSBWP and highest worth rod at position 48 may coexist and by definition, the reactor will remain shutdown without boron, or an examinee may not know MSBWP or how it relates to this decision block.. It is wrong because MSBWP and shutdown margin for the highest worth rod are separate considerations. The SRO can decide the reactor will remain shutdown without boron only if all rods are inserted to or beyond position 02 OR if all rods but one are fully inserted, with one one out past position 02 (i.e 04 – 48).

Answer C part 1 is plausible to the examinee who believes 24 rods inserted to 00, each one notch beyond 02, negate the one rod at 48, since one rod at 48 constitutes 24 notches. It is wrong because MSBWP is defined as all rods inserted to position 02. MSBWP is only met if all rods are inserted to 02 or 00. Part 2 is plausible and wrong for the same reason stated in distractor A.

Answer D part 1 is plausible and wrong for the same reason stated in distractor C. Part 2 is correct.		
Technical References: EOP-1A [RPV Control](Rev 22), PSTG (AMP-TBD00 Technical Basis)(Rev 10)		
References to be provided to applicants during exam: none		
Learning Objective: INT008-06-05 EO 4, State the criteria used to determine that the reactor will remain shutdown under all conditions without boron injection.		
Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.43(b)(5)	
Level of Difficulty:	3	
SRO Only Justification:		
This question requires assessment of plant conditions and knowledge of diagnostic steps and decision points in the EOPs that involve transitions to emergency contingency procedure EOP-6A.		
PSA Applicability:		
N/A		



ES-401 8 Attachment 2

Figure 2-2 Screening for SRO-Only Linked to 10 CFR 55.43(b)(5) (Assessment and Selection of Procedures)

Can the question be answered *solely* by knowing "systems knowledge" (i.e., how the system works, flowpath, logic, component location)?
Yes → RO question
No ↓

Can the question be answered *solely* by knowing immediate operator actions?
Yes → RO question
No ↓

Can the question be answered *solely* by knowing entry conditions for AOPs or plant parameters that require direct entry into major EOPs?
Yes → RO question
No ↓

Can the question be answered *solely* by knowing the purpose, overall sequence of events, or overall mitigative strategy of a procedure?
Yes → RO question
No ↓

Does the question require one or more of the following:

- assessment of plant conditions (normal, abnormal, or emergency) and then selection of a procedure or section of a procedure to mitigate or recover, or with which to proceed
- knowledge of when to implement attachments and appendices, including how to coordinate these items with procedure steps
- knowledge of diagnostic steps and decision points in the EOPs that involve transitions to event-specific sub-procedures or emergency contingency procedures
- knowledge of administrative procedures that specify hierarchy, implementation, and/or coordination of plant normal, abnormal, and emergency procedures

Yes → SRO-only question
No ↓

Question might not be linked to 10 CFR 55.43(b)(5) for SRO-only

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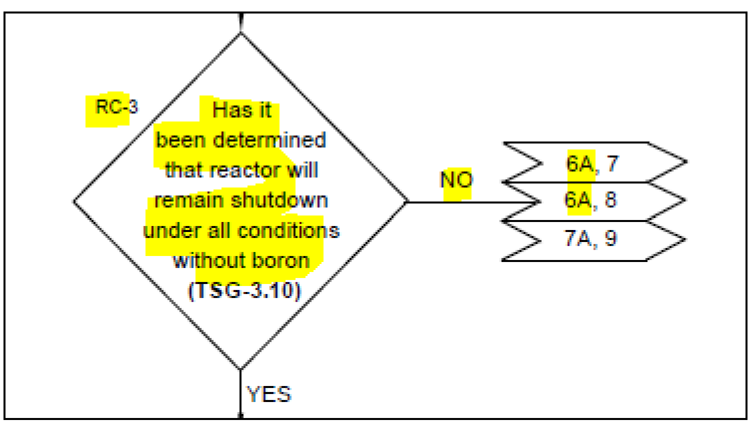


PSTG/SATG Step (First override before Step RC/L-2)

If while executing the following steps:

- It has not been determined that the reactor will remain shutdown under all conditions without boron (TSG-3.10), enter Contingency #5.
- RPV water level cannot be determined, enter Contingency #4.
- …

Discussion

Criteria used to demonstrate that the reactor will remain shutdown under all conditions without boron include determining:

- Control rod position is within the Maximum Subcritical Banked Withdrawal Position (MSBWP). The MSBWP is the greatest banked rod position at which the reactor will remain shutdown under all conditions. Refer to Section 18 of this appendix for a detailed discussion of the MSBWP.
- The existence of the core design basis shutdown margin with the single strongest control rod full-out and all other control rods full-in
- Compliance with Technical Specification requirements governing control rod position and the allowable number of inoperable control rods.

In some cases, the control room operating crew may be able to make the determination themselves. In most cases, however, it is expected that the determination will be made by a reactor engineer or other member of the technical support staff. The referenced TSG section provides additional guidance on performing the evaluation. Note that the instruction requires a positive determination, not only that the reactor *is* shutdown, but that it will *remain* shutdown, without reliance upon boron, under worst-case cold shutdown conditions. The phrase "without boron" does not imply that the condition cannot be met if boron has been injected, but that credit cannot be taken for the negative reactivity contributed by the boron. Control rod insertion alone must provide the necessary shutdown margin.

18.14 Maximum Subcritical Banked Withdrawal Position

The Maximum Subcritical Banked Withdrawal Position (MSBWP) is the greatest banked rod position at which the reactor will remain shutdown under all conditions.

The MSBWP is verified by fuel vendor analyses for each fuel load assuming:

1. The reactor core is at its most reactive exposure.
2. No xenon is present in the reactor core.
3. No voids are present in the reactor core.
4. RPV water is at its most reactive temperature.

The MSBWP is one of several criteria used to determine that the reactor will remain shutdown under all conditions without boron. This determination is made in the following PSTG steps:

- First override before Step RC/L-2
- Override before Step RC/P-1
- RC/P-3
- Override before Step RC/Q-1
- First override before Step C1-1
- PSTG Steps C2-1 and C2-2
- PSTG Steps C4-1 and C4-2
- First override before Step C4-1
- Override before Step C4-2.1
- Override before Step C5-1

8. PSTG/SATG Caution numbers do not coincide with EPG/SAG Caution numbers because some generic cautions do not apply to CNS and some CNS Cautions are not derived from the EPGs/SAGs. A cross-reference of Caution numbers is given below:

EPG/SAG Caution No.	PSTG/SATG Caution No.
1	1
2	N/A
3	3
4	2
5	4
6	7
7	8
N/A	5
N/A	6
8	9
9	10
N/A	11
N/A	12
N/A	13

9. The decisions to enter and exit failure-to-scram sections of the EPGs/SAGs and to perform actions affecting core reactivity (e.g., cool down the RPV) are based on criteria such as the banked control rod position with respect to the Maximum Subcritical Banked Rod Withdrawal Position (MSBWP) and a determination that the reactor will remain shutdown under all conditions without boron. Whenever the MSBWP is specified in the EPGs/SAGs, the second criterion is likewise specified. The MSBWP is determined in NEDC 97-089 and is assigned the value of 02. If all control rods are inserted to or beyond position 02, by definition, the reactor is and will remain shutdown under all conditions without boron. The first criterion (rod position) is thus a subset of the second criterion. It is therefore unnecessary to specify the MSBWP to effect the correct action with respect to failure-to-scram actions. Therefore, rods inserted to or beyond notch position 02, the Maximum

Examination Outline Cross-Reference	Level	SRO
300000 (SF8 IA) Instrument Air 2.1.7 Ability to evaluate plant performance and make operational judgments based on operating characteristics, reactor behavior, and instrument interpretation.	Tier#	2
	Group#	1
	K/A #	300000 G2.1.7
	Rating	4.7
	Revision	1
Revision Statement: Replaced K/A 2.2.40 with K/A 2.1.7 per NRC CE comments on "free review" and replaced question.		

Question 86

The plant is operating at rated power when a leak on the Instrument Air (IA) header occurs in the Reactor Building.

Which one of the following completes the statement below regarding the **HIGHEST** Instrument Air pressure that requires performing Procedure 2.1.5 [Reactor Scram] and when Attachment 2 [IA Pressure Loss] is required to be performed IAW Procedure 5.2AIR [Loss of Instrument Air]?

Entry into Procedure 2.1.5 is required if IA pressure lowers below ____(1)___.
Attachment 2 (IA Pressure Loss) is required to be performed ____(2)____.

A. (1) 77 psig
(2) anytime Procedure 5.2AIR is entered

B. (1) 77 psig
(2) ONLY when system pressure is considered to be too low to support continued operation

C. (1) 85 psig
(2) anytime Procedure 5.2AIR is entered

D. (1) 85 psig
(2) ONLY when system pressure is considered to be too low to support continued operation

Answer: B
Explanation: This question requires knowledge of AOP subsequent actions and when to implement abnormal procedure attachments.

Procedure 5.2AIR requires the CRS to enter Procedure 2.1.5, Reactor Scram, which implements reactor shutdown, when air header pressure is ≤ 77 psig based on the operating characteristics of systems supplied by instrument air. (Service Air automatically isolates <77 psig). Attachment 2 is also required to be implemented concurrently with the 5.2AIR body when IA pressure lowers below 77 psig which is the pressure considered too low to support continued operation.

Distracters:

Answer A part 1 is correct. Part 2 is incorrect due to Attachment 2 only being required to be implemented when IA pressure is considered too low to support continued operation. This choice is plausible due to confusing Attachment 2 title (IA Pressure Loss) with when to implement the attachment. The candidate that correctly recalls the IA lowering pressure milestones and confuses when to implement Attachment 2 would select this answer.

Answer C part 1 is incorrect due to IA pressure being ≤ 77 psig requires entry into procedure 2.1.5 and Attachment 2 only being required to be implemented when IA pressure is considered too low to support continued operation. This choice is plausible due to ≤ 85 psig being one of the lowering IA pressure milestones in the supplemental actions. Part 2 is plausible and wrong for the reasons given for distractor A. The candidate that confuses IA lowering pressure milestones and confuses when to implement Attachment 2 would select this answer.

Answer D part 1 is plausible and wrong for the reasons given for distractor C. Part 2 is correct.

Technical References: 5.2AIR {Loss of Instrument Air](Rev 23)

References to be provided to applicants during exam: none

Learning Objective:

COR0011702001070A Given a specific Plant Air system malfunction, determine the effect on any of the following: a. Plant operation

Question Source:	Bank #	12/2015 ILT NRC Q#79
(note changes; attach parent)	Modified Bank #	
	New	
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.43(b)(5)	
Level of Difficulty:	2	
SRO Only Justification:		

Knowledge of when to implement attachments and appendices, including how to

coordinate these items with procedure steps.
PSA Applicability:
N/A

from 12/2015 ILT NRC exam

Examination Outline Cross-Reference	Level	SRO
~~Revised question to determine when a scram is required based upon IA pressure and when Attachment 2 (IA Pressure Loss) is implemented.~~	Tier#	1
	Group#	1
	K/A #	295019.G2.1.7
	Rating	4.7

295019 Partial or Total Loss of Inst. Air

G2.1.7 Ability to evaluate plant performance and make operational judgments based on operating characteristics, reactor behavior, and instrument interpretation. (CFR: 41.5 / 43.5 / 45.12 / 45.13)

Question 79

The plant is operating at rated power when a leak on the Instrument Air (IA) header occurs in the Reactor Building.

Which one of the following completes the statement below regarding the **HIGHEST** Instrument Air pressure that requires performing Procedure 2.1.5 (Reactor Scram) and when Attachment 2 (IA Pressure Loss) is required to be performed IAW 5.2AIR Procedure (Loss of Instrument Air)?

Entry into Procedure 2.1.5 is required if IA pressure lowers below ____(1)____.
Attachment 2 (IA Pressure Loss) is required to be performed ____(2)____.

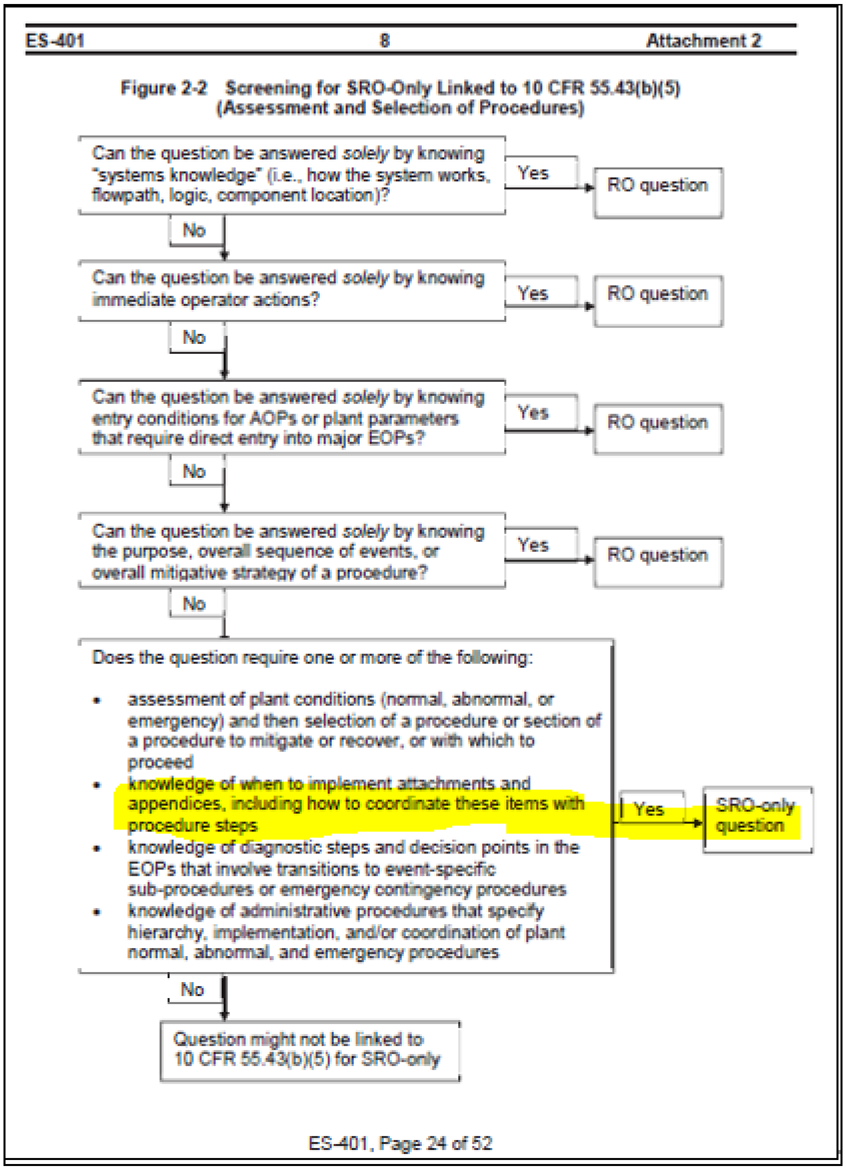
A. (1) 85 psig
(2) anytime Procedure 5.2AIR is entered

B. (1) 85 psig
(2) ONLY when system pressure is considered to be too low to support continued operation

C. (1) 77 psig
(2) anytime Procedure 5.2AIR is entered

D. (1) 77 psig
(2) ONLY when system pressure is considered to be too low to support continued operation

Answer:
D. (1) 77 psig



ES-401 8 Attachment 2
Figure 2-2 Screening for SRO-Only Linked to 10 CFR 55.43(b)(5) (Assessment and Selection of Procedures)
Can the question be answered solely by knowing "systems knowledge" (i.e., how the system works, flowpath, logic, component location)?
Yes
RO question
No
Can the question be answered solely by knowing immediate operator actions?
Yes
RO question
No
Can the question be answered solely by knowing entry conditions for AOPs or plant parameters that require direct entry into major EOPs?
Yes
RO question
No
Can the question be answered solely by knowing the purpose, overall sequence of events, or overall mitigative strategy of a procedure?
Yes
RO question
No
Does the question require one or more of the following:
• assessment of plant conditions (normal, abnormal, or emergency) and then selection of a procedure or section of a procedure to mitigate or recover, or with which to proceed
• knowledge of when to implement attachments and appendices, including how to coordinate these items with procedure steps
• knowledge of diagnostic steps and decision points in the EOPs that involve transitions to event-specific sub-procedures or emergency contingency procedures
• knowledge of administrative procedures that specify hierarchy, implementation, and/or coordination of plant normal, abnormal, and emergency procedures
Yes
SRO-only question
No
Question might not be linked to 10 CFR 55.43(b)(5) for SRO-only
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CNS OPERATIONS MANUAL EMERGENCY PROCEDURE 5.2AIR LOSS OF INSTRUMENT AIR	USE: CONTINUOUS QUALITY: QAPD RELATED EFFECTIVE: 8/28/19 APPROVAL: ITR-RDM OWNER: AOM-SUPPORT DEPARTMENT: OPS

Scram Actions

1. ENTRY CONDITIONS

1.1 INSTRUMENT AIR PRESSURE below green band and does not recover back into green band.

1.2 SERVICE AIR PRESSURE below green band and does not recover back into green band.

2. AUTOMATIC ACTIONS

2.1 1st Standby SACs loads when system pressure 93 to 99 psi.

2.2 2nd Standby SACs loads when system pressure 90 to 97 psi.

2.3 SA-PCV-609, SERVICE AIR SYSTEM ISOLATION, closes when service air pressure < 77 psig.

3. IMMEDIATE OPERATOR ACTIONS

3.1 None.

4. SUBSEQUENT OPERATOR ACTIONS

4.1 Record current time and date. Time/Date: ________/________

4.2 IF more than one rod drifting, THEN SCRAM and concurrently enter Procedure 2.1.5.

4.3 IF air drying/filtering components at fault, THEN perform following:

4.3.1 Open SA-MO-81, SA TO IA CROSSTIE (PANEL A).

4.3.2 Place standby dryer and filters in service per Procedure 2.2.59.

4.3.3 If necessary, manually bypass any obstructed component(s).

4.3.4 WHEN dryer and filter flow returned to service, THEN close SA-MO-81.

Scram Actions

4.4 IF SACs tripped, THEN have Operator locally reset per Procedure 2.2.59.

4.5 Make following announcement twice:

"All personnel using breathing equipment supplied by plant air move to an area with a clean atmosphere."

4.6 IF Primary Containment inerting in-progress, THEN secure inerting per Procedure 2.2.60.

4.7 Stop any work involving large air system loads.

4.8 At INSTRUMENT AIR PRESSURE ≤ 85 psig:

4.8.1 Ensure Steps 4.3 through 4.7 actions completed.

4.8.2 Place BF-C-1A, EMERG BSTR FAN, as follows:

4.8.2.1 Place switch for BF-C-1A, EMERG BSTR FAN, to RUN, then allow it to spring-return to AUTO (VBD-R).

4.8.2.2 AFTER BF-C-1A has started, THEN verify following:

a. EF-C-1B, TOILET EXH FAN, stops.

b. HV-270AV, CONTROL ROOM HVAC INLET VALVE, closes.

c. HV-271AV, CONTROL ROOM HVAC EMERGENCY BYPASS SYSTEM INLET VALVE, opens.

d. HV-272AV, CONTROL ROOM PANTRY EXHAUST FAN ISOLATION VALVE, closes.

4.8.3 IF radwaste discharge in-progress, THEN secure discharge as follows:

4.8.3.1 IF from Waste Sample Tanks, THEN perform following:

a. Close RW-AO-141A (B), WASTE SMPL PUMP DISCH.

b. Place switch for Waste Sample Pump A (B) in STOP.

c. Complete securing discharge per Procedure 2.5.1.6 as time permits.

4.8.3.2 IF from Floor Drain Sample Tank, THEN perform following:

a. Hold FLOOR DRAIN SAMPLE PUMP control switch in STOP position until pump stops running, then return to AUTO.

b. Place switch for RW-AO-227, FL DR SAMPLE DISCH VALVE, in CLOSE.

c. As time permits, complete securing discharge per Procedure 2.5.2.3.

4.8.4 Stop all radwaste processing.

4.8.5 Stop all fuel handling.

4.8.6 Bypass FPC F/Ds per Procedure 2.2.32.

4.8.7 In Diesel Generator Rooms, perform following:

4.8.7.1 Close IA-678, DG-1 IA SUPPLY ROOT (west wall of DG-1 Room above high pressure CO_2 bottles).

4.8.7.2 Slowly open DGSA-37, DG-1 AC-DG-1A AND AC-DG-1C BACKUP AIR SUPPLY (above and between air receivers and MCC-DG1).

4.8.7.3 Close IA-683, DG-2 IA SUPPLY ROOT (west wall of DG-2 Room above high pressure CO_2 bottles).

4.8.7.4 Slowly open DGSA-38, DG-2 AC-DG-1B AND AC-DG-1D BACKUP AIR SUPPLY (above and between air receivers and MCC-DG2).

4.8.8 IF high silt conditions exist in E Bay, THEN align SW System to E Bay spargers per Procedure 2.2.3.4.

4.8.9 Review Attachment 1 (Page 5) for significant loads and effects due to plant air loss.

4.9 At INSTRUMENT AIR PRESSURE ≤ 77 psig:

4.9.1 Concurrently perform following:

4.9.1.1 Attachment 2 (Page 9).

4.9.1.2 Procedure 2.1.5.

4.9.2 Transfer level control to HPCI/RCIC per Procedure 2.2.33.1 or 2.2.67.1.

4.9.3 Close all MSIVs.

4.9.4 Close MS-MO-74, INBD ISOL VLV.

4.9.5 Close MS-MO-77, OUTBD ISOL VLV.

4.9.6 To prevent RPV overfill, perform following:

4.9.6.1 Ensure both reactor feed pumps tripped.

4.9.6.2 Trip condensate booster pumps, if necessary.

ATTACHMENT 2 IA PRESSURE LOSS

ATTACHMENT 2 IA PRESSURE LOSS

1. IA PRESSURE LOSS

1.1 Close IA-MO-80, NON CRIT INSTRUMENT AIR ISOLATION (PANEL A).

1.2 IF Primary Containment inerting in-progress, THEN perform following:

CAUTION – Rupture disc on N_2 inerting line may have blown.

NOTE – Rupture disc PC-RD-NPS opens at 60 psig.

1.2.1 Check N_2 flow on PC-FI-515, N_2 FLOW (VBD-H).

1.2.1.1 IF N_2 flow > 0 cfm, THEN assume rupture disc blown and perform following:

a. Make gaitronics announcement to evacuate Reactor Building.

b. Restrict Reactor Building access to all personnel until habitability at acceptable levels.

c. Contact RP to determine Reactor Building habitability.

1.2.2 At N_2 storage tank, close N2-V-99, NITROGEN SUPPLY ROOT ISOLATION VALVE (YD-S, south of RR Airlock).

1.2.3 Shut down Primary Containment N_2 Inerting System per Procedure 2.2.60.

1.2.4 Open N2-V-99.

1.3 Manually control hotwell level:

1.3.1 Close MC-37, FCV-17 INLET (T-882-N east of TEC pumps).

1.3.2 Close CM-11, LCV-2C NORMAL MAKEUP INLET (T-882-N, east end of TEC HXs).

1.3.3 Close MC-776, LCV-2D NORMAL DUMP INLET (T-882-N, northeast corner above FCV-17).

1.3.4 Throttle following, as necessary, to maintain hotwell level:

1.3.4.1 CM-16, LCV-2B, SURGE MAKEUP BYPASS (T-882-N, east end of TEC HXs).

1.3.4.2 MC-36, LCV-2A, SURGE DUMP BYPASS (T-882-N, east of TEC pumps).

ATTACHMENT 3 INFORMATION SHEET

ATTACHMENT 3 INFORMATION SHEET

1. DISCUSSION

1.1 This procedure provides instructions for a loss of Instrument Air (IA). The procedure is comprised of the main body and two Attachments.

1.1.1 The procedure body provides instructions that attempt to restore system pressure, reduce system load, and anticipate a subsequent pressure loss. The procedure body instructions are to be performed whether Attachment 2 is entered or not.

1.1.2 The procedure body actions are grouped according to observed Instrument Air pressure values. The procedure is structured to address a steadily lowering IA pressure. If the rate of IA pressure decay does not allow completion of actions at the specified pressure, the next grouping contains a step to trigger the performance of previous actions (e.g., if pressure drops rapidly to < 77 psig), Attachment 2 contains a step to trigger performance of actions that would have been performed at > 77 psig.

1.1.3 Attachment 2 provides instructions that are performed when system pressure is considered to be too low to support continued operation. Attachment 2 is to be performed in conjunction with the procedure body instructions.

1.1.4 Attachment 1 provides a list of loads and what effect the pressure loss will have on the load. The list is not all inclusive and only includes those loads considered to be significant or important.

1.2 A loss of IA, while in the process of inerting primary containment, would cause the containment isolation valves to fail closed, the nitrogen purge supply rupture disc to fail and/or the associated relief valve to open. This would result in the release of N_2 directly to the Reactor Building.

1.3 The loss of IA for more than a very short time will necessitate emergency plant shutdown from power. The air operated valves and components are designed to a fail safe and allow the plant to be shut down and placed in a MODE 4 condition. Some local manual valve positioning will be necessary.

1.4 Attachment 2 provides instructions that ensure a nitrogen supply to the drywell header; help to ensure availability of the relief valves. If in MODE 3 or 4, three safety relief valves are required to remain available for Alternate Decay Heat Removal.

1.5 A non-critical instrument air isolation will cause a severe reduction in feedwater heating, resulting in unsafe plant operating conditions.Ⓡ[1]

1.6 Large air loads referred to in the Subsequent Actions are those which require prior Control Room authorization per Procedure 0.31.

Examination Outline Cross-Reference	Level	SRO
295002 (APE 2) Loss of Main Condenser Vacuum / 3 2.2.42 Ability to recognize system parameters that are entry-level conditions for Technical Specifications.	Tier#	1
	Group#	2
	K/A #	295002 G2.2.42
	Rating	4.6
	Revision	0
Revision Statement:		

Question 87

The plant was at 100% power when loss of condenser vacuum due to boot seal failure.

Mitigating Task Scram actions are complete.

Turbine trip actions are complete.

Condenser vacuum is 5 "Hg, slowly lowering.

The following indications on Panel 9-3 for MSIVs exist:

- For MSIV 86D:
    - At control switch - Red light is ON and Green light is OFF.
    - On Isolation Valve Positions mimic - Red light is ON and Green light is OFF.
- For ALL other MSIVs' indications - Red lights are OFF and Green lights are ON.

The DC ammeter for MSIV 86D at Panel 9-42 indicates 85 milliamps.

Which one of the following actions is required for these conditions?

A. Initiate an ACTIVE LCO for TS 3.6.1.3 [Primary Containment Isolation Valves], for MSIV 86D

B. Initiate a POTENTIAL LCO for TS 3.6.1.3 [Primary Containment Isolation Valves], for MSIV 86D

C. Enter an ACTIVE LCO for TS 3.3.3.1 [Post Accident Monitoring Instrumentation], PCIV Position for MSIV 86D

D. Enter a POTENTIAL LCO for TS 3.3.3.1 [Post Accident Monitoring Instrumentation], PCIV Position for MSIV 86D

Answer: A
Explanation: MSIV (Group 1) isolates on condenser vacuum low, 10”Hg (TS ≥8”Hg). With the given annunciators in and seven of eight MSIVs closed, isolation instrumentation has performed its function. MSIV 86D should have closed on the isolation signal or when its control switch was placed to CLOSE. MSIV 86D position is indicated by red and green lights above the control switch on Panel 9-3 and on the Isolation Valve Status mimic on the vertical section of Panel 9-3. Both red lights are actuated by one limit switch when the valve is not fully closed, and both green lights are actuated by another limit switch when the valve is not fully open. Position indication is required to be operable IAW TS 3.3.3.1 during Modes 1 and 2. MSIVs have two solenoid valves, one AC powered and one DC powered, that must de-energize to cause the MSIV to close. In the stem, the DC ammeter indicates current to the DC solenoid. This represents the DC solenoid valve for MSIV 86D is energized, a condition that causes MSIV 86D to remain open. This is consistent with the position indication showing the valve is fully open. Therefore, three separate components, the ammeter and both open and closed limit switches, indicate MSIV 86D is open. Since all other MSIVs indicate closed, there is no other indication, such as steam flow or equalizing header pressure, that could be used to indicate the inboard MSIV is open. Since it is fully open, MSIV 86D is inoperable. MSIV 86D is required to be operable IAW the applicability of TS 3.6.1.3. The applicability for TS 3.6.1.3 states PCIVs are required operable in Modes 1, 2, and 3, when the associated isolation instrumentation is required operable IAW TS 3.3.6.1. Condenser vacuum low, function 1d of TS Table 3.3.6.1-1, is required operable at all times during Mode 1, and when any turbine stop valve is not closed in Modes 2 and 3. Conditions given in the stem represent the plant in Mode 3, since Mitigating Task Scram Actions are complete, which place the Reactor Mode Switch in Shutdown. And turbine stop valves are closed, since turbine trip actions are completed. Therefore, MSIV 86D is not required to be operable with respect to condenser vacuum low trip function. However, it is required to be operable at all times during Mode 3 with respect to TS Table 3.3.6.1-1 functions 1a (RPV water level low), 1c (MSL flow high), and 1e (MS tunnel temperature high). With MSIV 86D fully open with automatic isolation signals in, it is inoperable for required automatic functions. Therefore, an ACTIVE LCO must be entered for MSIV 86D per TS 3.6.1.3. Procedure 2.0.11 requires that an ACTIVE LCO be entered for those conditions where the SSC design function is required to be operable in the current mode as defined by Technical Specifications. Whereas a POTENTIAL LCO would be required for a condition where a SSC is inoperable, but is not required to be operable, in the current mode.

It is important to enter the TS that governs the actuated device versus the TS that governs the actuation instrumentation for the given conditions. For an inoperable MSIV, TS 3.6.1.3 Action A.1 requires isolating the affected penetration within 8 hours. If only the isolation instrumentation was inoperable and untrippable, TS 3.3.6.1 Action B.1 and D.1 would provide up to 13 hours to isolate the penetration.

Distracters:
Answer B is plausible because condenser vacuum has exceeded the trip setpoint, and MSIV 86B has not closed, and because the condenser vacuum low trip function is not required to be operable under given plant conditions.. It is also wrong because MSIVs are required to be operable at all times during Mode 3 for TS Table 3.3.6.1-1 functions 1a (RPV water level low), 1c MSL flow high), and 1e (MS tunnel temperature high); therefore, an ACTIVE LCO is required.

Answer C is plausible because MSIV 86D should be closed, but the position indication is not consistent with a closed valve. The examinee who assumes MSIV 86D is closed, since all other MSIVs indicate closed, and who does not know TS 3.3.3.1 only applies in Modes 1 and 2 or does not recognize the plant is in Mode 3, may chose this answer. If the plant was in Mode 1 or 2 and the position indication was inoperable, an active LCO for TS 3.3.3.1 would be required. This answer is wrong because the ammeter indicates the DC solenoid valve for MSIV 86D is energized, which would cause the valve to remain open. The position indication governed by TS 3.3.3.1 is operable.

Answer D is plausible because MSIV 86D should be closed, but the position indication is not consistent with a closed valve. An examinee may incorrectly assume MSIV 86D is closed but the position indication is errant. If that was the case, this answer would be correct, because TS 3.3.3.1 would apply to the position indication, which is not required operable in Mode 3, so only a potential LCO would be required.

Technical References: TS 3.3.6.1 [Primary Containment Isolation Instrumentation], TS 3.6.1.3 [PCIVs], Alarm Card 9-5-1/A-1 [Group 1 Isol Channel A](Rev 36), Alarm Card 9-5-1/A-2 [Group 1 Isol Channel B](Rev 36), GE dwg 791E266 sheet 11

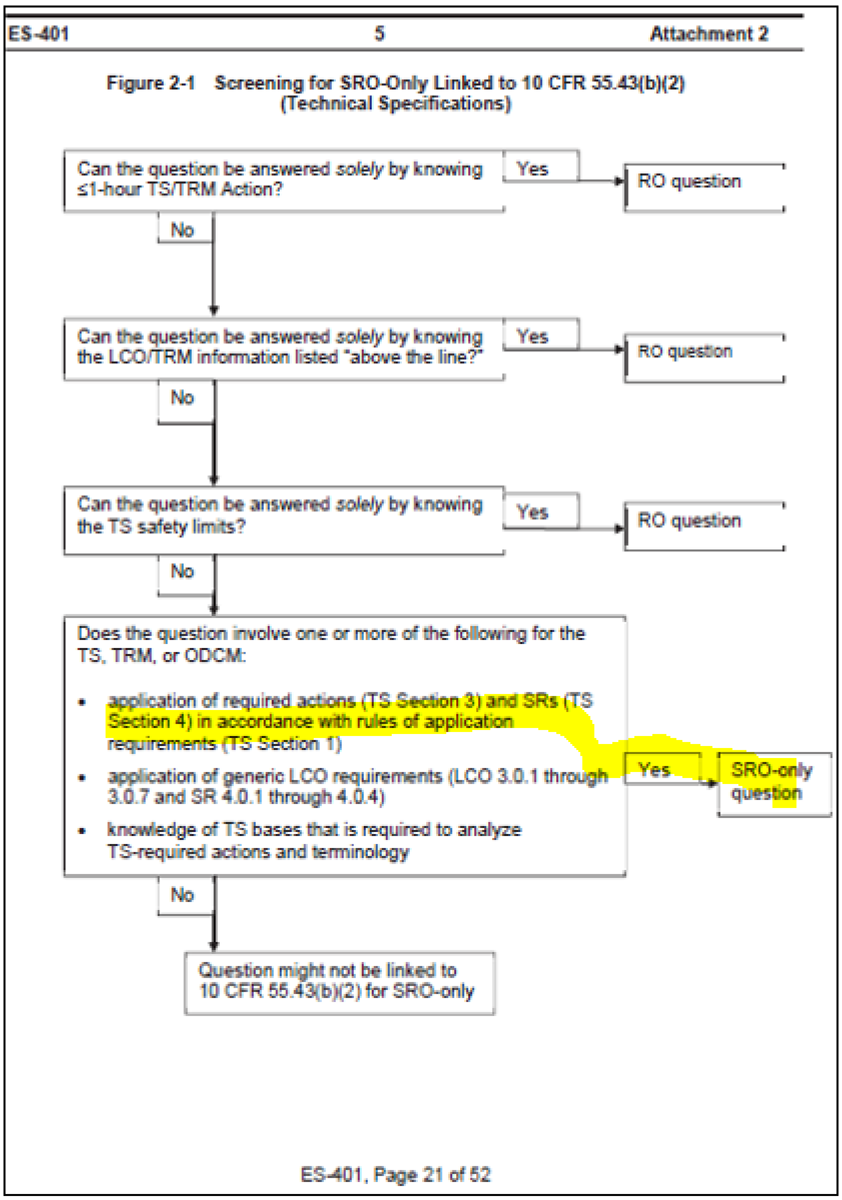
References to be provided to applicants during exam: none

Learning Objective: INT007-05-07 EO-1, Given a set of plant conditions, recognize non-compliance with a Chapter 3.6 LCO.

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X

Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X

10CFR Part 55 Content:	55.43(b)(2)	
Level of Difficulty:	3	
SRO Only Justification:		
This question requires determining operability of required components in order to properly apply TS action statements. It also requires knowledge of the administrative procedure governing entering LCOs for application of TS required actions		
PSA Applicability:		
Top 10 Risk Significant Systems – PCIVs, PCIS		



ES-401 5 Attachment 2

Figure 2-1 Screening for SRO-Only Linked to 10 CFR 55.43(b)(2) (Technical Specifications)

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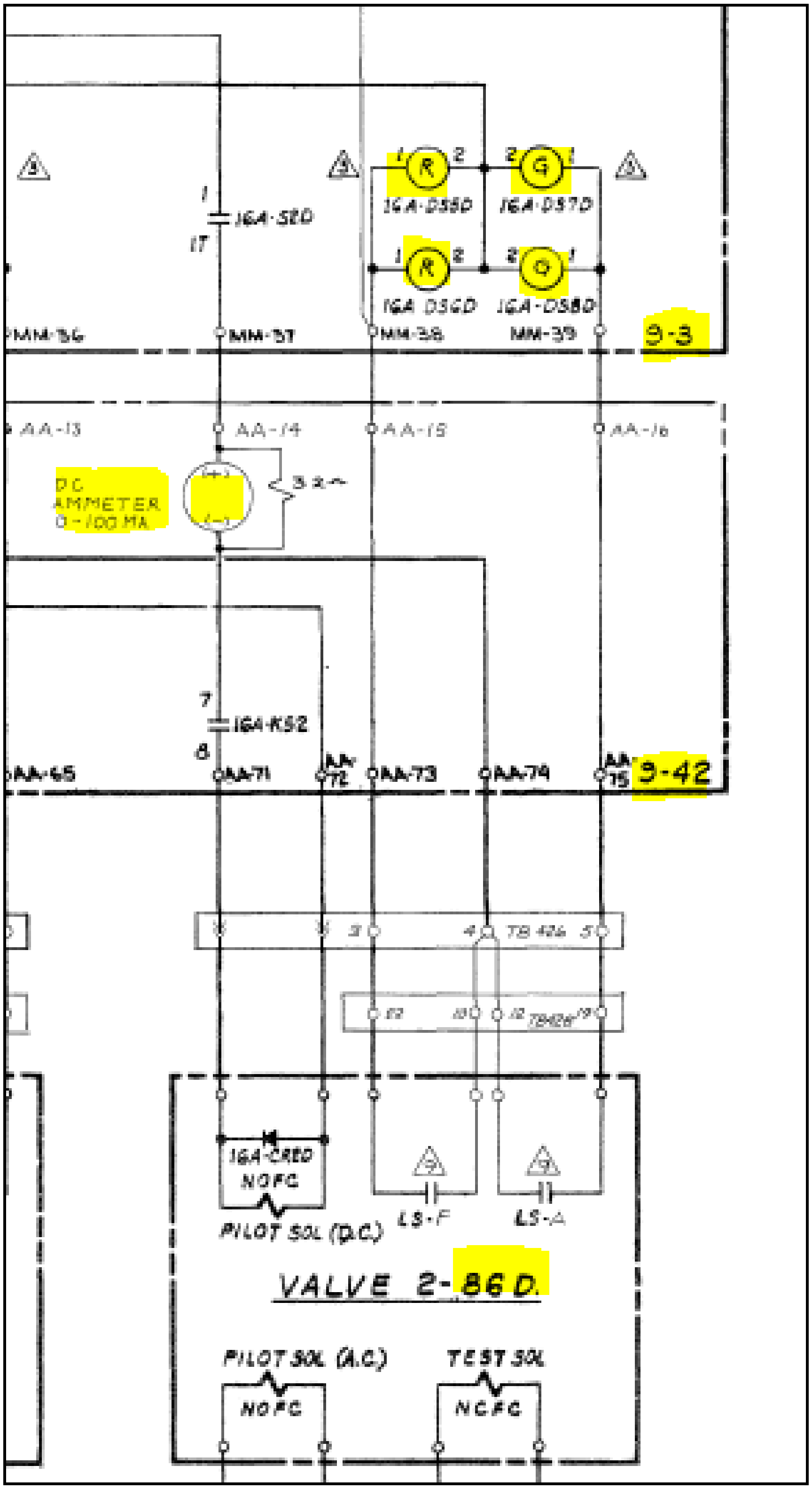
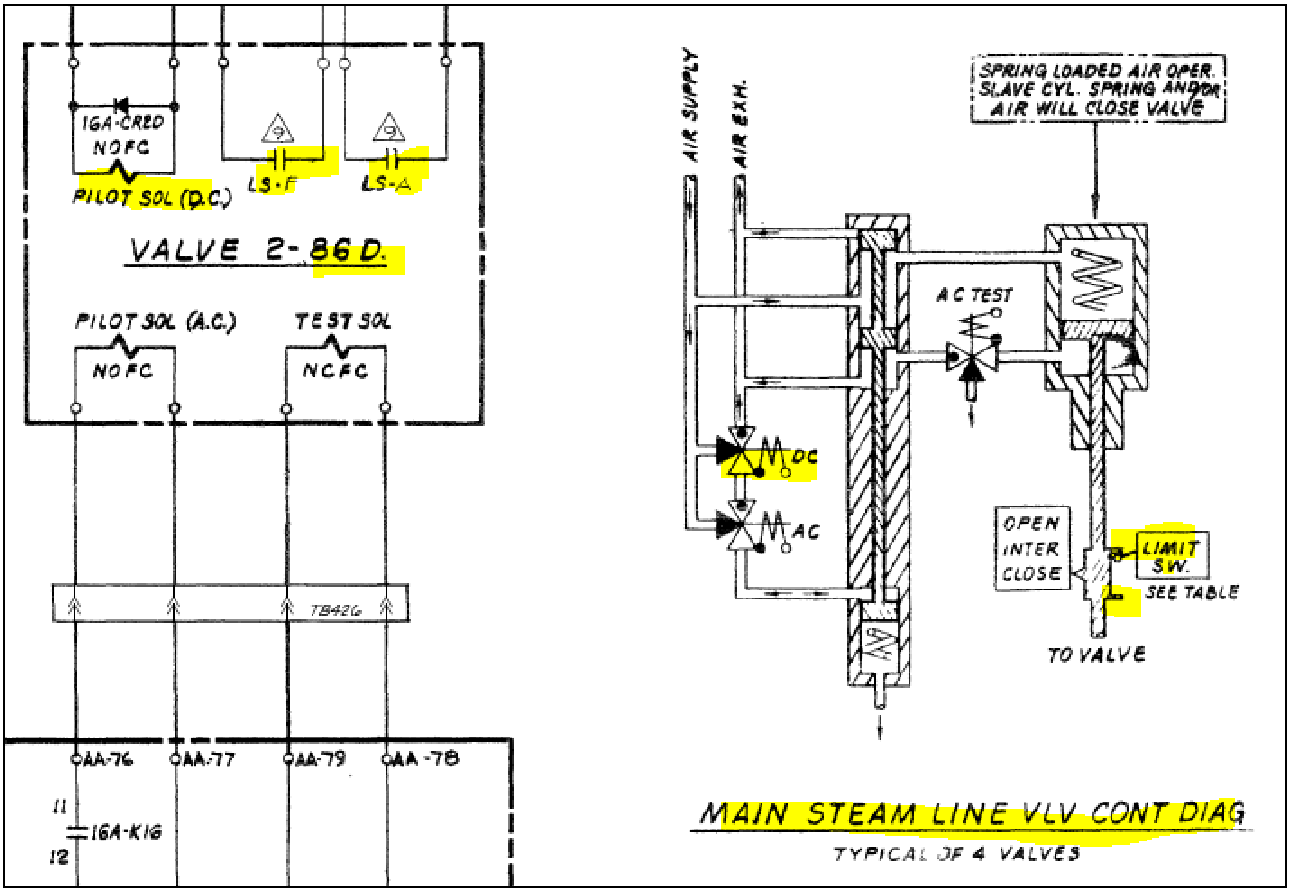
From GE dwg 791E266 sheet 11



From GE dwg 791E266 sheet 11



SETPOINT	CIC	9-5-1/A-1
(2100) GROUP I ISOLATION CHANNEL A1 TRIP or (2101) GROUP I ISOLATION CHANNEL A2 TRIP relay operation caused by:	PCIS-REL-K7A or PCIS-REL-K7C	
1. Reactor low water level of -104.39" (Tech Spec ≥ -113")	1. NBI-LIS-57A or NBI-LIS-58A (Switch #1)	
2. Main steam line low pressure of 849 psig (Tech Spec ≥ 835 psig)	2. MS-PS-134A or MS-PS-134C	
3. Main steam tunnel temperature high of 185°F (Tech Spec ≤ 195°F)	3. MS-TS-121 through MS-TS-124	
4. Condenser low vacuum of 10" Hg (Tech Spec ≥ 8" Hg)	4. MS-PS-103A or MS-PS-103C	
5. Main steam line high flow of 105.8 psid (Tech Spec ≤ 142.7% of rated flow [111.7 psid])	5. MS-DPIS-116A, MS-DPIS-116C, MS-DPIS-117A, MS-DPIS-117C, MS-DPIS-118A, MS-DPIS-118C, MS-DPIS-119A, or MS-DPIS-119C	

PROBABLE CAUSES

- A single channel failure is indicative of an instrument malfunction.

REFERENCES

- Technical Specifications LCO 3.3.6.1, Primary Containment Isolation Instrumentation.
- General Operating Procedure 2.1.5, Reactor Scram.
- General Operating Procedure 2.1.22, Recovering From a Group Isolation.
- Emergency Procedure 5.1BREAK, Pipe Break Outside Secondary Containment.

GROUP I ISOL CHANNEL A	PANEL/WINDOW: 9-5-1/A-1

1. AUTOMATIC ACTIONS

1.1 If both Channels A and B are received, Group 1 isolation occurs (MSIV and MS line drain valves).

1.2 Resultant reactor scram from MSIV closure if REACTOR MODE switch in RUN.

2. OPERATOR OBSERVATION AND ACTION

2.1 IF both Channels A and B trip, THEN ensure following:

2.1.1 Group 1 isolation.

2.1.2 Reactor scram.

2.2 Enter following procedures as dictated by plant conditions:

2.2.1 Procedure 2.1.5.

2.2.2 Procedure 5.1BREAK.

2.3 IF only Channel A trips, THEN perform following:

2.3.1 Determine and correct cause.

2.3.2 Reset half Group 1 isolation per Procedure 2.1.22.

Primary Containment Isolation Instrumentation
3.3.6.1

Table 3.3.6.1-1 (page 1 of 3)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Main Steam Line Isolation					
a. Reactor Vessel Water Level - Low Low Low (Level 1)	1,2,3	2	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.6	≥ -113 inches
b. Main Steam Line Pressure - Low	1	2	E	SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.6	≥ 835 psig
c. Main Steam Line Flow - High	1,2,3	2 per MSL	D	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.6	≤ 142.7% rated steam flow
d. Condenser Vacuum - Low	1, 2[(a)], 3[(a)]	2	D	SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.6	≥ 8 inches Hg vacuum
e. Main Steam Tunnel Temperature - High	1,2,3	2 per location	D	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.6	≤ 195°F
2. Primary Containment Isolation					
a. Reactor Vessel Water Level - Low (Level 3)	1,2,3	2	G	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.6	≥ 3 inches
b. Drywell Pressure - High	1,2,3	2	G	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.6	≤ 1.84 psig
c. Reactor Building Ventilation Exhaust Plenum Radiation - High	1,2,3	2	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.6	≤ 49 mR/hr
d. Main Steam Line Radiation - High	1,2,3	2	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 3 times full power background
e. Reactor Vessel Water Level - Low Low Low (Level 1)	1,2,3	2	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.6	≥ -113 inches

(continued)

(a) With any turbine stop valve not closed.

PCIVs
3.6.1.3

3.6 CONTAINMENT SYSTEMS

3.6.1.3 Primary Containment Isolation Valves (PCIVs)

LCO 3.6.1.3 Each PCIV, except reactor building-to-suppression chamber vacuum breakers, shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
When associated instrumentation is required to be OPERABLE per LCO 3.3.6.1, "Primary Containment Isolation Instrumentation."

ACTIONS

-----NOTES-----

1. Penetration flow paths may be unisolated intermittently under administrative controls.

2. Separate Condition entry is allowed for each penetration flow path.

3. Enter applicable Conditions and Required Actions for systems made inoperable by PCIVs.

4. Enter applicable Conditions and Required Actions of LCO 3.6.1.1, "Primary Containment," when PCIV leakage results in exceeding overall containment leakage rate acceptance criteria.

CONDITION	REQUIRED ACTION	COMPLETION TIME

1.7.2 ACTIVE LCO - An Active LCO shall be entered for those conditions where the SSC design function is required to be OPERABLE in the current mode as defined by Technical Specifications.

1.7.3 POTENTIAL LCO - A POTENTIAL LCO shall be entered when any of the following conditions are met:

1.7.3.1 A condition where any SSC is inoperable, but is not required to be OPERABLE, in the current mode.

1.7.3.2 A condition where any SSC is inoperable, but the minimum required number of components is still met.

1.7.3.3 A condition where any SSC is OPERABLE based on actions required to verify <u>and/or</u> compensate for the specific condition.

Examination Outline Cross-Reference	**Level**	SRO
700000 (APE 25) Generator Voltage and Electric Grid Disturbances / 6 Ability to determine and/or interpret the following as they apply to GENERATOR VOLTAGE AND ELECTRIC GRID DISTURBANCES: AA2.07 Operational status of engineered safety features	**Tier#**	1
	Group#	1
	K/A #	700000 AA2.07
	Rating	4.0
	Revision	0
Revision Statement:		

Question 88

Reference Provided

The plant is at 10% power.

ESST is NOT loaded.

DG2 has been tagged out of service for 5 hours to repair a lube oil leak.

Doniphan Control (DCC) has called the control room and stated that thunderstorms and tornados are causing grid disturbances and Contingency Analysis is NOT solving.

SSST LTC-X tap has been raised and voltages being maintained as follows:

- 4160V Bus 1F – 3900 V
- 4160V Bus 1G – 3900 V
- ESST - 64 kV (via OPPD line)

What is the MAXIMUM time before Mode 3 is required to be entered?

A. 7 days, 12 hours

B. 7 days, 7 hours

C. 36 hours

D. 13 hours

Answer: D
Explanation:

This is a modified version of 9/2018 ILT NRC Q#82. There are two onsite emergency AC power sources governed by TS 3.8.1, DG1 and DG2. There are two offsite emergency AC power sources governed by TS 3.8.1, the SSST and the ESST. One onsite source, DG2 is given as being tagged out of service, so it is inoperable. At 10% power, the SSST is supplying 4160V ESF Buses 1F and 1G. The NSST, which supplies 4160V ESF Buses 1F and 1G via 4160V Buses 1A and 1B when the generator is on line, is not in service because the generator is off line at 10% power. With SSST supplying 4160V ESF Buses 1F and 1G and either of their voltages below 3950 V, the SSST is required to be declared inoperable per procedure 5.3GRID. Therefore, with 4160V ESF Bus 1F and 1G voltage below 3950 V, the SSST, one offsite AC source, is inoperable. ESST operability is based on the primary side voltage being ≥70 kV under no-load conditions. For the situation given, the ESST is not loaded. ESST no-load voltage is below 70 kV; therefore, the ESST, another offsite AC source, is inoperable per 5.3GRID.

With one onsite AC source inoperable and both offsite AC sources inoperable, TS 3.8.1 Condition G is required to be entered, which requires immediate entry into TS 3.0.3. LCO 3.0.3 requires entry into Mode 3 within 13 hours.

Distracters:

Answer A is plausible to the examinee who does not know some operability requirements listed in procedure 5.3GRID, believes only one offsite AC source is inoperable, does not consider DG2 inoperability and applies only TS 3.8.1 Condition A. Adding to plausibility that only one offsite source is inoperable is that one bus, Bus 1G, is above the low voltage limit, so an examinee may believe the SSST remains operable. It is plausible to the examinee who does not recognize there are TS 3.8.1 Conditions that address inoperability of combinations of offsite and onsite AC sources. This is plausible because TS 3.8.1 Conditions A, B, C, and E address inoperability of only offsite AC sources or inoperability of onsite AC sources, but not both. Also, a common error is to not look further once an applicable TS Condition is identified. For the examinee who believes only Condition A applies, this answer is plausible because it reflects the completion time of Condition A (Action A.3) which has a completion time of 7 days before Condition F (Action F.1) would be entered, which requires being in Mode 3 within 12 hours. It is wrong because both SSST and ESST, two offsite circuits, are inoperable, and DG2, one onsite AC source, is inoperable; therefore, Condition G applies, so Mode 3 must be entered within a maximum of 13 hours.

Answer B is plausible to the examinee who does not know some operability requirements listed in procedure 5.3GRID, believes only one offsite AC source is inoperable, also recognizes DG2 is inoperable and poses a separate concern, and applies only TS 3.8.1 Conditions A and B. It is plausible to the examinee who does not recognize there are TS 3.8.1 Conditions that address inoperability of combinations of offsite and onsite AC sources. This is plausible because TS 3.8.1 Conditions A, B, C, and E address inoperability of only offsite AC sources or inoperability of onsite AC sources, but not both. Also, a common error is to not look further once an applicable TS Condition is identified. For the examinee who believes only Conditions A and B apply, this answer is plausible because it reflects the most limiting completion time of

the two. Both Condition A (Action A.3) and B (Action B.4) have completion times of 7 days before Condition F (Action F.1) would be entered, which requires being in Mode 3 within 12 hours. But DG2 has already been out of service for 5 hours. The remaining time for Condition B plus the 12 hour completion time of Condition F equals 7 days, 7 hours. Condition A with Condition F would provide 7 days 12 hours for reaching Mode 3. It is wrong because both SSST and ESST, two offsite circuits, are inoperable, and DG2, one onsite AC source, is inoperable; therefore, Condition G applies, so Mode 3 must be entered within a maximum of 13 hours. Answer C is plausible to the examinee who does not know some operability requirements listed in procedure 5.3GRID and believes only one offsite AC source is inoperable and applies TS 3.8.1 Condition D, for one offsite source and one onsite source inoperable. It is also plausible to the examinee who recognizes both offsite sources are inoperable but who does not recognize there are TS 3.8.1 Conditions that address inoperability of combinations of offsite and onsite AC sources and selects TS 3.8.1 Condition C. Both Conditions C (Action C.2) and D (Actions D.1 and D.2). have 24 hour completion times. 24 hours combined with the 12 our completion time of Condition F (Action F.1) yields in 36 hours to be in Mode 3. It is wrong for the same reason given for distractor A.		
Technical References: TS 3.8.1 [AC Sources – Operating], Procedure 5.3GRID [Degraded Grid Voltage](Rev 53)		
References to be provided to applicants during exam: TS 3.8.1 [AC Sources – Operating] LCO and Actions, only.(pages 3.8-1 thru 3.8-4)		
Learning Objective: INT007-05-09 EO 3, Given a set of plant conditions that constitutes non-compliance with a Section 3.8 LCO, determine the ACTIONS that are required.		
Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	9/2018 ILT NRC Q#82
	New	
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.43(b)(2)	
Level of Difficulty:	3	
SRO Only Justification:		
This question requires knowledge of details within subsequent actions and an attachment of an AOP, application of TS required actions, and application of generic TS 3.0.3.		
PSA Applicability:		

Top 10 Risk Significant Systems – Emergency AC Power

9/2018 ILT NRC Q#82

Question 82

Reference Provided

The plant is at 25% power.

Doniphan Control (DCC) has called the control room and stated that thunderstorms and tornados are causing grid disturbances such that several 161kV low voltage alarms are occurring and will continue to occur at least for the next 30 minutes.

Security Analysis is NOT solving.

161 kV line voltage has lowered since Security Analysis last solved.

The voltages being maintained at the transformers are currently as follows:

- 0800 SSST – 162 kV
- 0800 ESST - 66 kV (via OPPD line)

- Buses 1F and 1G have been transferred to SSST and are being maintained at 4045 V at SSST Tap setting 16

Regarding Technical Specifications, as the CRS you …

A. Enter TS 3.8.1 and transition to TS 3.0.3 immediately ONLY.

B. Perform SR 3.8.1.1 to verify Operability of Offsite Power ONLY.

C. Enter TS 3.8.1 and declare one offsite source INOPERABLE ONLY.

D. Enter TS 3.8.1 and declare two offsite sources INOPERABLE ONLY.

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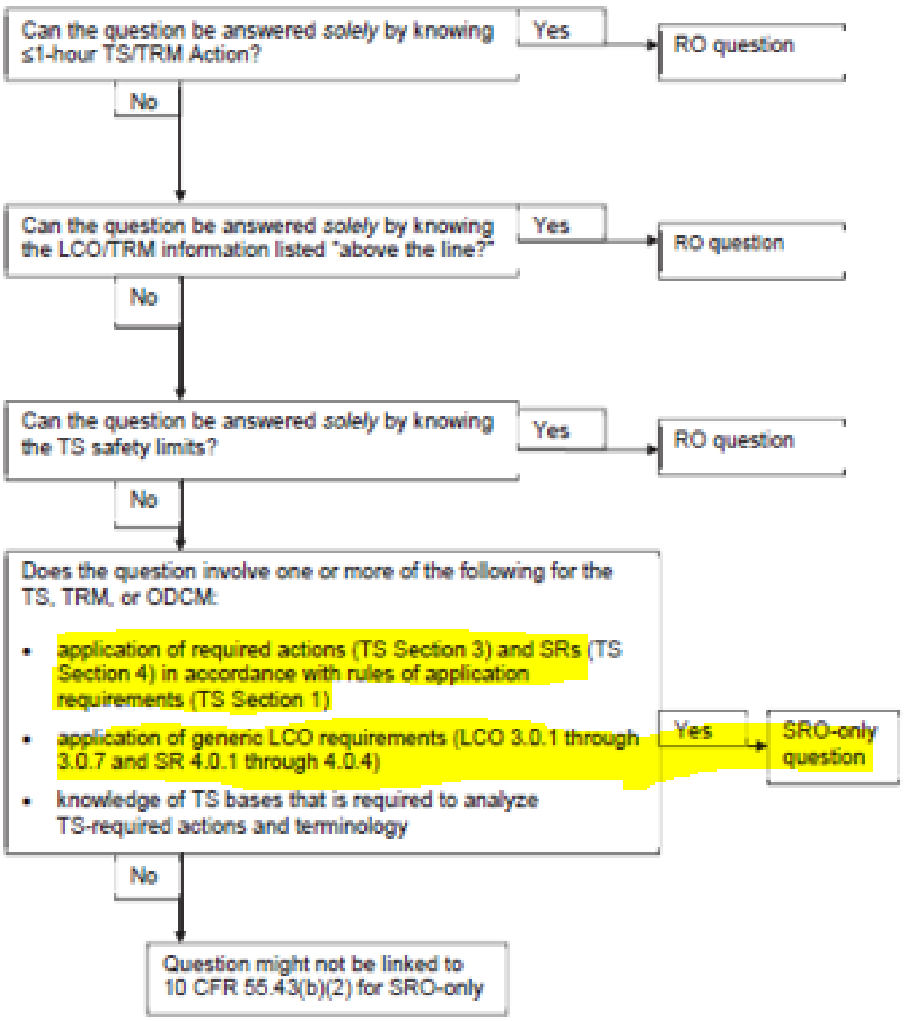
ES-401 Written Examination Question Worksheet Form ES-401

Answer: D

Figure 2-1 Screening for SRO-Only Linked to 10 CFR 55.43(b)(2) (Technical Specifications)



4.9.4 IF voltage is still degraded or oscillating < 4050V, THEN perform following:

4.9.4.1 Consider securing loads per applicable procedure to help restore voltage. Loads may include, but are not limited to:

a. Circulating water pumps.

b. Service water pumps.

c. Welding.

4.9.4.2 IF voltage on 4160V Bus 1F and/or 1G continues to degrade or oscillate and cannot be maintained ≥ 3950V, THEN perform following:

a. IF SSST is AVAILABLE, THEN transfer 4160V Bus 1A, 1B, 1C, and/or 1D to SSST per Procedure 2.2.18.1.

4.10 IF SSST supplying 4160V Bus 1F or 1G and voltage degraded or oscillating < 4050V, THEN perform following:

4.10.1 Contact DCC System Operator for 161 kV line status and predicted reliability.

4.10.2 Consider raising Startup Transformer LTC-X Tap Position:

4.10.2.1 To raise STARTUP XFMR X VOLTAGE, momentarily place STARTUP XFMR X VOLTAGE ADJUST switch to RAISE and release.

4.10.2.2 To lower STARTUP XFMR X VOLTAGE, momentarily place STARTUP XFMR X VOLTAGE ADJUST switch to LOWER and release.

4.10.2.3 Repeat Steps 4.10.2.1 and 4.10.2.2, as needed.

4.10.2.4 WHEN voltage adjustment completed, THEN update STARTUP TRANSFORMER BACKUP VOLTAGE BAND information associated with AS LEFT Tap Position on Panel C plaque per Procedure 2.2.15, Voltage Adjustment section.

4.10.3 Consider securing loads per applicable procedure to help restore voltage. Loads may include, but are not limited to:

4.10.3.1 Circulating water pumps.

4.10.3.2 Service water pumps.

4.10.3.3 Welding.

4.10.4 IF voltage on 4160V Bus 1F and/or 1G continues to degrade and cannot be maintained ≥ 3950V, THEN declare 161 kV line and SSST inoperable and enter appropriate Condition and Required Action of LCO 3.8.1, AC Sources - Operating, or LCO 3.8.2, AC Sources - Shutdown.

ATTACHMENT 1 DCC NOTIFICATION/LINE VOLTAGE

ATTACHMENT 1 DCC NOTIFICATION/LINE VOLTAGE

1. DCC NOTIFICATION

1.1 IF DCC System Operator has commenced Manual Load Shedding Plan, THEN review this procedure. No further action required.

1.2 IF Contingency Analysis violation occurs on SSST 4160 voltage for the contingency "Cooper Unit Off-Line, SSST Voltage" due to undervoltage, THEN declare 161 kV line and SSST inoperable and enter appropriate Condition and Required Action of LCO 3.8.1, AC Sources - Operating, or LCO 3.8.2, AC Sources - Shutdown.©[2]

1.3 IF Contingency Analysis violation occurs on ESST 4160 voltage for the contingency "Cooper Unit Off-Line, ESST Voltage" due to undervoltage, THEN declare 69 kV line and Emergency Transformer inoperable, and enter appropriate Condition and Required Action of LCO 3.8.1, AC Sources - Operating, or LCO 3.8.2, AC Sources - Shutdown.©[2]

1.4 IF Contingency Analysis violation for any CNS contingency is due to post-contingent overvoltage, THEN contact SED/DED to evaluate.©[2]

1.5 IF DCC System Operator notifies CNS Control Room of any of following alarms or Procedure 2.1.12 directed entry, THEN perform following:©[2]

1.5.1 LOW VOLTAGE ON CNS 161 KV BUS

NOTE – "No-load" assumes both RRMGs aligned to SSST.

1.5.1.1 IF Contingency Analysis is <u>not</u> in service or <u>not</u> solving, and DCC low voltage alarm in or no-load voltage < 161 kV, THEN perform following:

a. Assess Operability (reference Attachment 3, Step 1.12); or

b. Declare 161 kV line and SSST inoperable and enter appropriate Condition and Required Action of LCO 3.8.1, AC Sources - Operating, or LCO 3.8.2, AC Sources - Shutdown.

1.5.2 LOW VOLTAGE ON CNS 69 KV BUS

1.5.2.1 IF Contingency Analysis is <u>not</u> in service <u>or not</u> solving, and DCC low voltage alarm in or no-load voltage < 70.0 kV, THEN declare 69 kV line and Emergency Transformer inoperable and enter appropriate Condition and Required Action of LCO 3.8.1, AC Sources - Operating, or LCO 3.8.2, AC Sources - Shutdown.

in the "Division of Operating Reactors Guidelines for Evaluating Environmental Qualifications of Class 1E Electrical Equipment in Operating Reactors" (DOR Guidelines), in accordance with 10CFR50.49(k). Replacement components and new EQ equipment are qualified in accordance with Regulatory Guide 1.89, Revision 1, in accordance with 10CFR50.49(l).

1.7.3 Channel Independence[7]

1.7.3.1 Criteria for Preserving the Independence of Redundant Channels

A. Reactor Protection System (RPS) and Primary Containment Isolation System (PCIS) - General Rules

1. Wiring for the RPS outside of the main protection system cabinet is run in rigid conduits used for no other wiring and is conspicuously identified at all junction or pull boxes. Under-vessel neutron monitoring cables are exempted from the requirement of rigid conduit installation because of space limitations and need for flexibility on SRM and IRM cables.

2. Wiring to redundant sensors on a common process tap are run in separate conduits to their separate destinations in order to meet the single failure criteria.

3. Wiring for sensors of more than one variable in the same trip channel may be run in the same conduit.

4. Wires from both RPS trip system trip actuators to a single group of scram solenoids may be run in a single conduit. However, a single conduit does not contain wires to more than one group of scram solenoids. Wiring for two solenoids on the same control rod may be run in the same conduit.

5. Cables through the primary containment penetrations are so grouped as to insure that failure of all cabling in a single penetration cannot prevent a scram and isolation. (This applies specifically to the neutron monitoring cables and MSIV position switches.)

6. In accordance with the contract specifications, the cables are generally continuous in length between terminations with minimum splicing permitted.

7. RPS Special Considerations: The APRM of the RPS has six (A, B, C, D, E, F) independent input instrument channels for each measured parameter (see Figure VII-1-3). The six separate conduits for the six sensors for a specific parameter are kept segregated. In no case could the total disabling of equipment within a single division be capable of preventing a required scram action under permitted bypass conditions.

B. Engineered Safety Feature (ESF) and Other Class IE Equipment

The following general rules are used to determine the allocation of the electrical wiring between the segregated divisions.

1. Basic Criteria: Separation is such that no single failure can prevent operation of an engineered safety function (i.e., core cooling). Redundant (even dissimilar) systems may be required to perform the required function to satisfy the single failure criteria.

Table VII-1-1 illustrates the separation of subsystems of the ESF and the PCIS Valves.

USAR

TABLE VII-1-5[16]

SYSTEM AND SUBSYSTEM SEPARATION

DIVISION I	DIVISION II
Core Spray A	Core Spray B
Residual Heat Removal A	Residual Heat Removal B
Low Pressure Coolant Injection	Low Pressure Coolant Injection
Automatic Depressurization	High Pressure Coolant Injection
Inboard Nuclear Steam Supply Shutoff Valves	Outboard Nuclear Steam Supply Shutoff Valves
Reactor Protection System Div. IA - A1, Div. IB - B1	Reactor Protection System A Div. IIA - A2, Div. IIB - B2
Standby Gas Treatment A	Standby Gas Treatment B
Emergency Equipment Cooling Water: Service Water A&C RHR Service Water Booster A&C Reactor Equipment Cooling A&B	Emergency Equipment Cooling Water: Service Water B&D RHR Service Water Booster B&D Reactor Equipment Cooling C&D
Reactor Core Isolation Cooling (Not an Engineered Safety Feature)	
Diesel Generator DG1	Diesel Generator DG2
4160 Volt Switchgear 1F, EG1	4160 Volt Switchgear 1G, EG2
480 Volt Unit Substation 1F	480 Volt Unit Substation 1G
Critical Motor Control Centers K, L, Q, R, RA, DG1, CA, LX	Critical Motor Control Centers S, T, Y, RB, DG2, CB, TX
Critical Distribution Panel A	Critical Distribution Panel B
Critical Control Panel CCP1A	Critical Control Panel CCP1B
Reactor Prot. System Power Panel A	Reactor Prot. System Power Panel B
Station Batteries & Chargers A	Station Batteries & Chargers B
DC Switchgear A	DC Switchgear B

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources — Operating

LCO 3.8.1 The following AC electrical power sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the onsite Class 1E AC Electrical Power Distribution System; and

b. Two diesel generators (DGs).

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

-----NOTE-----
LCO 3.0.4.b is not applicable to DGs

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One offsite circuit inoperable.	A.1 Perform SR 3.8.1.1 for OPERABLE offsite circuit.	1 hour AND Once per 8 hours thereafter
	AND	
	A.2 Declare required feature(s) with no offsite power available inoperable when the redundant required feature(s) are inoperable.	24 hours from discovery of no offsite power to one division concurrent with inoperability of redundant required feature(s)
	AND	
		(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.3	Restore offsite circuit to OPERABLE status.	7 days AND 14 days from discovery of failure to meet LCO
B. One DG inoperable.	B.1	Perform SR 3.8.1.1 for OPERABLE offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND		
	B.2	Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND		
			(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.3.1	Determine OPERABLE DG is not inoperable due to common cause failure.	24 hours
	<u>OR</u>		
	B.3.2	Perform SR 3.8.1.2 for OPERABLE DG.	24 hours
	<u>AND</u>		
	B.4	Restore DG to OPERABLE status.	7 days <u>AND</u> 14 days from discovery of failure to meet LCO
C. Two offsite circuits inoperable.	C.1	Declare required feature(s) inoperable when the redundant required feature(s) are inoperable.	12 hours from discovery of Condition C concurrent with inoperability of redundant required feature(s)
	<u>AND</u>		
	C.2	Restore one offsite circuit to OPERABLE status.	24 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One offsite circuit inoperable. AND One DG inoperable.	-------------NOTE------------- Enter applicable Conditions and Required Actions of LCO 3.8.7, "Distribution Systems — Operating," when Condition D is entered with no AC power source to either division. -------------------------------	
	D.1 Restore offsite circuit to OPERABLE status.	24 hours
	OR	
	D.2 Restore DG to OPERABLE status.	24 hours
E. Two DGs inoperable.	E.1 Restore one DG to OPERABLE status.	2 hours
F. Required Action and associated Completion Time of Condition A, B, C, D, or E not met.	F.1 Be in MODE 3.	12 hours
	AND	
	F.2 Be in MODE 4.	36 hours
G. Three or more required AC sources inoperable.	G.1 Enter LCO 3.0.3.	Immediately

3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

LCO 3.0.1 LCOs shall be met during the MODES or other specified conditions in the Applicability, except as provided in LCO 3.0.2 and LCO 3.0.7.

LCO 3.0.2 Upon discovery of a failure to meet an LCO, the Required Actions of the associated Conditions shall be met, except as provided in LCO 3.0.5 and LCO 3.0.6.

If the LCO is met or is no longer applicable prior to expiration of the specified Completion Time(s), completion of the Required Action(s) is not required, unless otherwise stated.

LCO 3.0.3 When an LCO is not met and the associated ACTIONS are not met, an associated ACTION is not provided, or if directed by the associated ACTIONS, the unit shall be placed in a MODE or other specified condition in which the LCO is not applicable. Action shall be initiated within 1 hour to place the unit, as applicable, in:

a. MODE 2 within 7 hours;

b. MODE 3 within 13 hours; and

c. MODE 4 within 37 hours.

Exceptions to this Specification are stated in the individual Specifications.

Where corrective measures are completed that permit operation in accordance with the LCO or ACTIONS, completion of the actions required by LCO 3.0.3 is not required.

LCO 3.0.3 is only applicable in MODES 1, 2, and 3.

LCO 3.0.4 When an LCO is not met, entry into a MODE or other specified condition in the Applicability shall only be made:

(continued)

BASES

ACTIONS (continued)

G.1

Condition G corresponds to a level of degradation in which all redundancy in the AC electrical power supplies has been lost. At this severely degraded level, any further losses in the AC electrical power system will cause a loss of function. Therefore, no additional time is justified for continued operation. The station is required by LCO 3.0.3 to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function. Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the DGs are in general conformance with the recommendations of Regulatory Guide 1.9 (Ref. 9), Regulatory Guide 1.108 (Ref. 10), and Regulatory Guide 1.137 (Ref. 11).

The minimum steady state output voltage of 3950 V is approximately 95% of the nominal 4160 V output voltage. This value, which is consistent with ANSI C84.1 (Ref. 12), allows for voltage drop to the terminals of 4000 V motors whose minimum operating voltage is specified as 90% or 3600 V. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating. The specified maximum steady state output voltage of 4400 V is equal to the maximum operating voltage specified for 4000 V motors. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V motors is no more than the maximum rated operating voltages. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ± 2% of the 60 Hz nominal frequency and are derived from the recommendations found in Safety Guide 9 (Ref. 3).

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source and that appropriate

Examination Outline Cross-Reference	Level	SRO
295010 (APE 10) High Drywell Pressure / 5 Ability to determine and/or interpret the following as they apply to HIGH DRYWELL PRESSURE: AA2.02 Drywell pressure	Tier#	1
	Group#	2
	K/A #	295010 AA2.02
	Rating	3.9
	Revision	0
Revision Statement:		

Question 89

A LOCA is in progress with the following conditions:

- Drywell pressure 63 psig, rising slowly
- Torus water level 29 feet, rising slowly

(1) What procedure is required to be used to vent primary containment under these conditions?

AND

(2) What vent path is required to be used under these conditions?

A. (1) 5.8.17 [Primary Containment Venting]
(2) Torus vent path

B. (1) 5.8.17 [Primary Containment Venting]
(2) Drywell vent path

C. (1) 5.8.18 [Primary Containment Venting for PCPL, PSP, Primary Containment Flooding, or Early Containment Venting]
(2) Torus vent path

D. (1) 5.8.18 [Primary Containment Venting for PCPL, PSP, Primary Containment Flooding, or Early Containment Venting]
(2) Drywell vent path

Answer: D
Explanation: Conditions given represent drywell pressure slightly above the Primary Containment Pressure Limit (PCPL-A), which is the lesser of:

- The pressure capability of the primary containment.
- The maximum primary containment pressure at which vent valves sized to reject all decay heat from the containment can be opened and closed.
- The maximum primary containment pressure at which SRVs can be opened and will remain open.

The PCPL is a function of primary containment water level and primary containment temperature. At CNS, RPV vent valve operability is not a concern in derivation of the PCPL because RPV venting can be accomplished using the motor operated main steam line drain valves. Operability of these valves are not affected by containment atmospheric pressure.

EOP-3A step PC/P-6 requires emergency venting the containment IAW EP 5.8.18 when drywell pressure cannot be maintained below PCPL-A. Per PSTGs "cannot be maintained" means The value of an identified parameter is/is not able to be held within the specified limit. Once the parameter does exceed the limit, the action must be performed.

EP 5.8.18 contains various methods/vent paths to vent primary containment. Venting from the Torus is employed first because the drywell atmosphere is first scrubbed by the suppression pool before being released through the vent. However, once Suppression Pool level reaches 28.5 feet, the Torus vent path is isolated and venting through a drywell vent path is performed.

Distracters:
Answer A part 1 is plausible because EOP-3A step PC/P-1 requires venting primary containment using EP 5.8.17 to control PC pressure below 1.84 psig. This answer is wrong because EP 5.8.17 is intended to maintain drywell pressure below 1.84 psig and does not permit overriding interlocks to vent at drywell pressures >1.84 psig. With drywell pressure >1.84 psig, the associated vent paths are unavailable unless isolation interlocks are first defeated. Part 2 is plausible because venting from the Torus is preferred over the drywell vent path because the suppression pool provides scrubbing of fission products from the drywell atmosphere before it is released. This answer is wrong because EP 5.8.18 requires using the drywell vent path when Suppression Pool level is ≥28.5 feet, because the Torus vent path becomes submerged, so Suppression Pool water containing fission products may be discharged from the Torus vent path at this level.

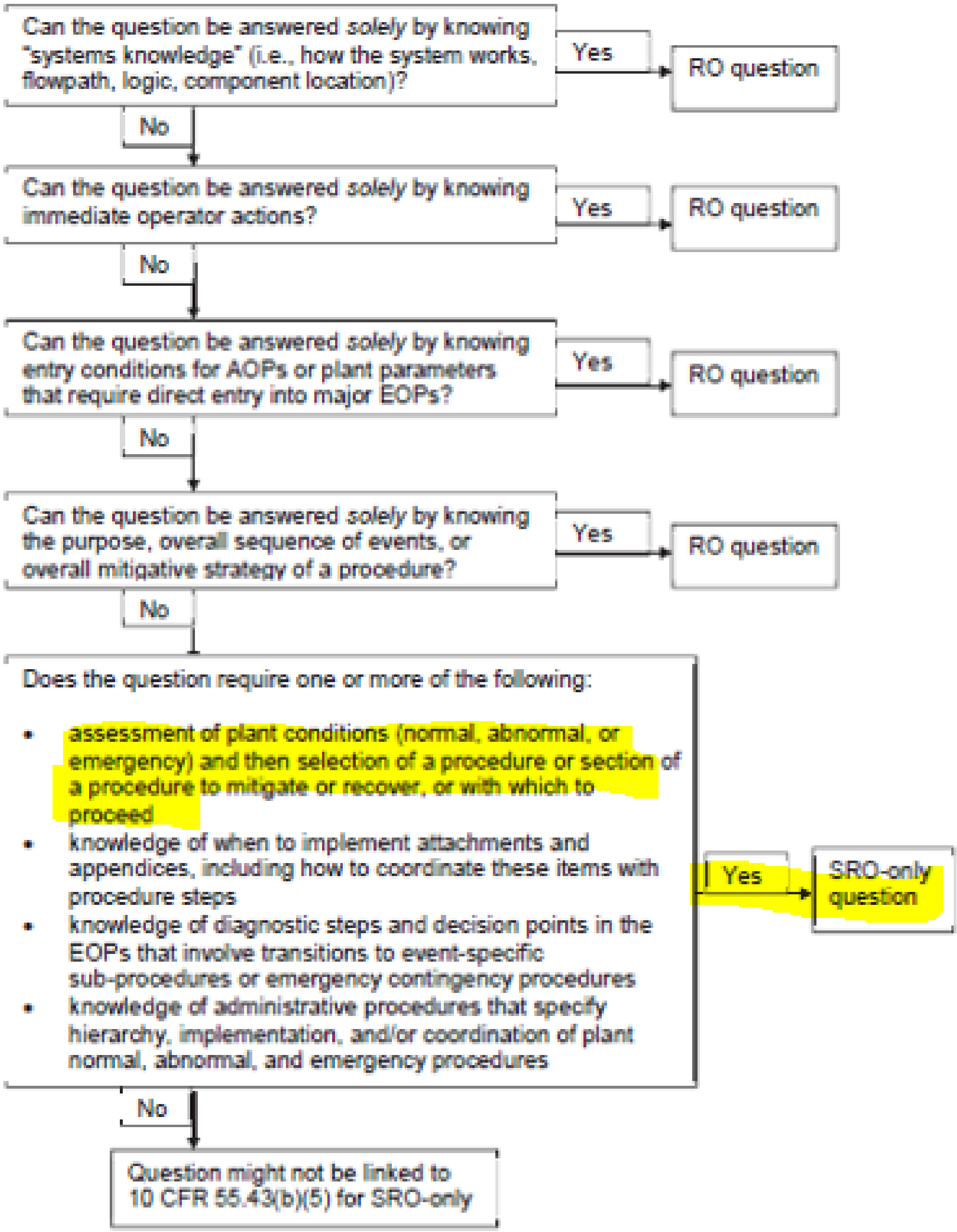
Answer B part 1 is plausible and wrong for the reason stated for distractor A. Part 2 is correct.

Answer C part 1 is correct. Part 2 is plausible and wrong for the reason stated for distractor A.

Technical References: EOP-3A [Primary Containment Control](Rev 18), Procedure 5.8.17 [Primary Containment Venting](Rev 12), Procedure 5.8.18 [Primary

Containment Venting for PCPL, PSP, Primary Containment Flooding, or Early Containment Venting](Rev 21), PSTG (AMP-TBD00 Technical Basis)(Rev 10)		
References to be provided to applicants during exam: none		
Learning Objective: INT008-06-13 EO-11, Given plant conditions and EOP Flowchart 3A, PRIMARY CONTAINMENT CONTROL, discuss required actions; EO-12, Given plant conditions and EOP flowchart 3A, PRIMARY CONTAINMENT CONTROL, discuss the reasons for the actions contained in the steps		
Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.43(b)(5)	
Level of Difficulty:	3	
SRO Only Justification:		
This requires evaluation of plant conditions and selection of a procedure with which to proceed. It also involves knowledge of the content of the procedure versus knowledge of overall mitigative strategy or purpose.		
PSA Applicability:		
Top 10 Risk Significant Systems – Primary Containment		

Figure 2-2 Screening for SRO-Only Linked to 10 CFR 55.43(b)(5) (Assessment and Selection of Procedures)



C. Facility Licensee Procedures Required To Obtain Authority for Design and Operating Changes in the Facility [10 CFR 55.43(b)(3)]

Some examples of SRO exam items for this topic include the following:

- screening and evaluation processes under 10 CFR 50.59, "Changes, Tests and Experiments"
- administrative processes for temporary modifications
- administrative processes for disabling annunciators
- administrative processes for the installation of temporary instrumentation
- processes for changing the plant or plant procedures

Section IV provides an example of a satisfactory SRO-only question related to this topic.

D. Radiation Hazards That May Arise during Normal and Abnormal Situations, including Maintenance Activities and Various Contamination Conditions [10 CFR 55.43(b)(4)]

Some examples of SRO exam items for this topic include the following:

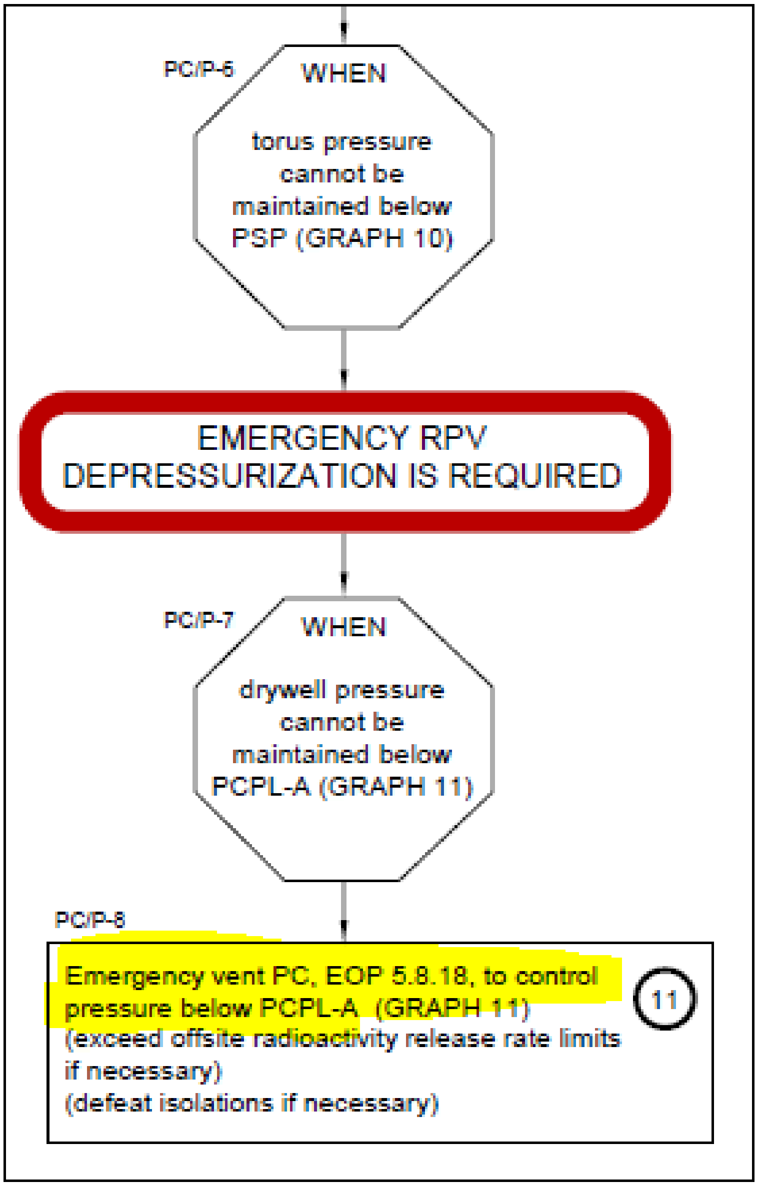
- process for gaseous/liquid release approvals (i.e., release permits)
- analysis and interpretation of radiation and activity readings as they pertain to the selection of administrative, normal, abnormal, and emergency procedures
- analysis and interpretation of coolant activity, including comparison to emergency plan criteria and/or regulatory limits

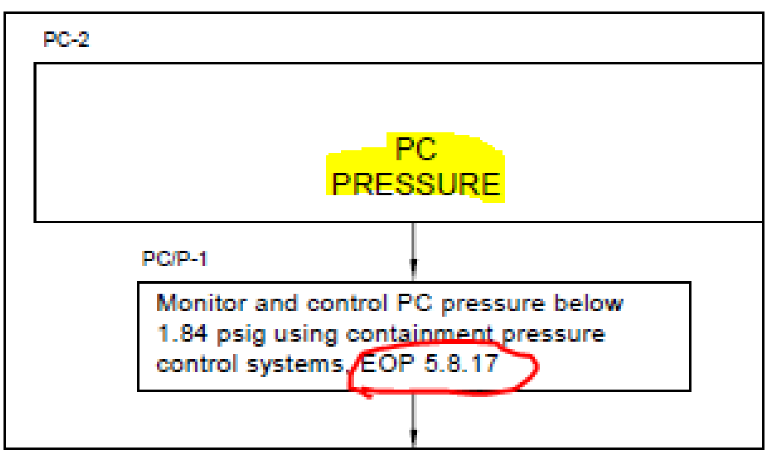
SRO-only knowledge should not be claimed for questions that can be answered *solely* based on RO knowledge of radiological safety principles (e.g., radiation work permit requirements, stay time, and DAC hours).

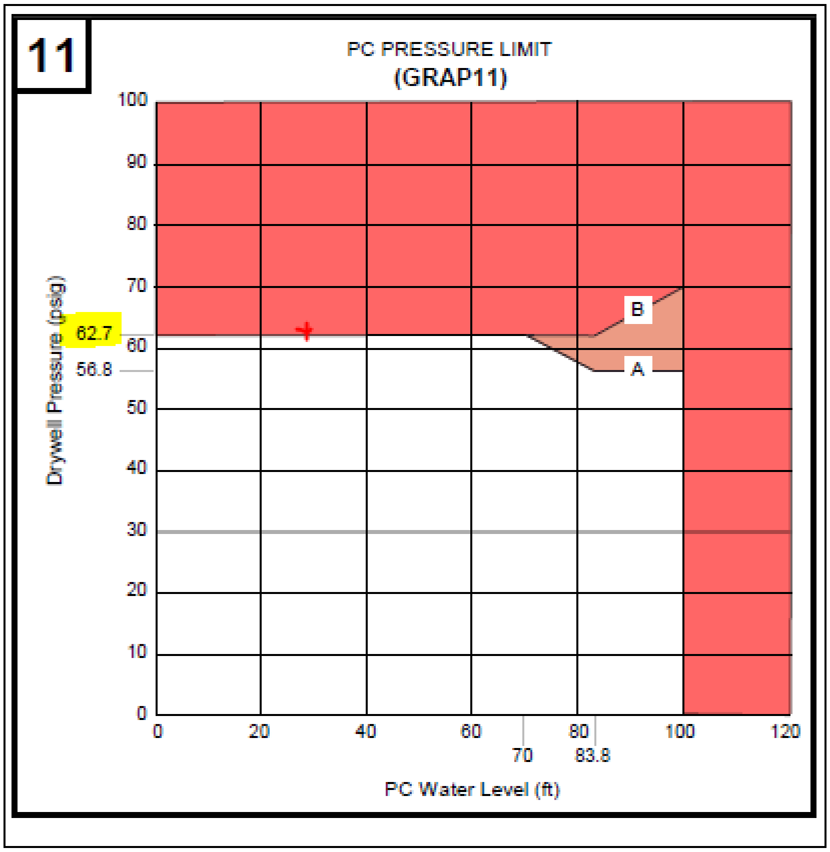
E. Assessment of Facility Conditions and Selection of Appropriate Procedures during Normal, Abnormal, and Emergency Situations [10 CFR 55.43(b)(5)]

This 10 CFR 55.43 topic involves both (1) assessing plant conditions (normal, abnormal, or emergency) and then (2) selecting a procedure or section of a procedure to mitigate or recover, or with which to proceed. One area of SRO-level knowledge (with respect to selecting a procedure) is knowledge of the content of the procedure versus knowledge of the procedure's overall mitigative strategy or purpose.

From EOP-3A


PC/P-6
WHEN
torus pressure cannot be maintained below PSP (GRAPH 10)
EMERGENCY RPV DEPRESSURIZATION IS REQUIRED
PC/P-7
WHEN
drywell pressure cannot be maintained below PCPL-A (GRAPH 11)
PC/P-8
Emergency vent PC, EOP 5.8.18, to control pressure below PCPL-A (GRAPH 11)
(exceed offsite radioactivity release rate limits if necessary)
(defeat isolations if necessary)
11


PC-2
PC PRESSURE
PC/P-1
Monitor and control PC pressure below 1.84 psig using containment pressure control systems, EOP 5.8.17



PSTG / SATG

AMP-TBD00
Tech. Basis – App. B

Similarly, if RPV water level indications are driven offscale high and the upscale indications are believed to be valid, level can be determined to be above the top of the fuel. Whether an offscale indication can be considered valid, however, and the length of time an offscale indication can be relied upon, requires a judgment based on the nature of the event, plant conditions, and the instrument characteristics.

Can/Cannot be maintained above/below The value of an identified parameter is/is not able to be held within the specified limit. The determination requires an evaluation of system performance and availability in relation to parameter values and trends. An instruction prescribing action when a parameter cannot be maintained above or below a specified limit neither requires nor prohibits anticipatory action—depending upon plant conditions, the action may be taken as soon as it is determined that the limit will ultimately be exceeded, or delayed until the limit is actually reached. Once the parameter does exceed the limit, however, the action must be performed; it may not be delayed while attempts are made to restore the parameter to within the desired control band.

ATTACHMENT 4 INFORMATION SHEET

ATTACHMENT 4 INFORMATION SHEET

1. DISCUSSION

1.1 There are two basic strategies employed within this procedure. To allow clarification in discussion they are "Emergency Primary Containment Venting" and "Early Primary Containment Venting".

1.2 Emergency primary containment venting for PCPL is venting to maintain PCPL and employs a graduated increase in venting methods until pressure can be restored and maintained below that limit of concern. The following is provided to clarify the use of emergency primary containment venting:

1.2.1 Emergency primary containment venting for PSP or PCPL must be performed expeditiously and usually considered a last resort. Delays might result in irreparable damage to the primary containment. Delays may also prevent timely core re-submergence under severe accident conditions.

1.2.2 Emergency containment venting may be performed exceeding Off-Site Dose Assessment Manual off-site radioactive release rate limits and overriding interlocks, as necessary, in order to vent through progressively larger flowpaths.

1.2.3 Suppression pool water level has a direct effect on the efficiency of the chosen vent path, due to the "scrubbing" effect of the water on fission products. If suppression pool level is < 28.5', venting will be through the torus. However, if it is ≥ 28.5', venting will be through drywell.

1.2.4 When venting for PCPL, the intent of this procedure is to vent before drywell pressure reaches PCPL (Curve A or B), and to reduce and maintain PC pressure below the limits of the applicable PCPL curve (Graph 11). Venting the PC below PCPL will protect the PC and limit off-site release and should be vented low enough that the limit will not be directly challenged again. Additionally, degrading plant conditions may require further reduction in PC | pressure.

1.2.5 Decisions concerning timing and duration of PC venting include the following considerations:

- Venting should be performed without exceeding applicable off-site radioactivity release rate limits if possible.
- Venting should be performed using a filtered release path or suppression pool scrubbing.
- If possible, venting should be coordinated with evacuation procedures.
- If possible, venting should be performed during favorable meteorological conditions. Venting should be performed without interfering with key Operator actions in the Reactor Building.

5. VENTING TORUS USING 1" VENT LINE

NOTE – Suppression pool water level needs correction per Procedure 2.2.9 if associated core spray pump is operating and Level Recorder PC-LRPR-1A or PC-LRPR-1B will be used.

5.1 IF during performance of Steps 5.2 through 5.11, suppression pool water level is ≥ 28.5' as indicated on any below listed indication, THEN perform following:

- Corrected level PMIS point value SPDS0065, AVE CORR SUPP POOL WR LEVEL; or
- PC-LRPR-1A, CONTAINMENT/TORUS PRESS & LEVEL RECORDER (PNL 9-3); or
- PC-LRPR-1B, CONTAINMENT/TORUS PRESS & LEVEL RECORDER (PNL 9-4).

5.1.1 Secure PC venting from torus as follows:

5.1.1.1 Ensure PC-MO-305 ISOLATION OVERRIDE in NORMAL (PNL P2).

5.1.1.2 Ensure PC-MO-305, VALVE MO 230 BYPASS VLV (VBD-H), closed.

5.1.1.3 Ensure PC-MO-1308, TORUS VENT ISOLATION VLV (PNL P2), closed.

5.1.1.4 Inform CRS torus no longer being vented.

NOTE – Section 9 provides specific guidance on which vent path to utilize.

5.1.2 Go to Section 9 to vent containment from drywell via appropriate path.

5.2 Ensure SGT System in service per Procedure 2.2.73.

5.3 Ensure DAMPER AD-R-1A & AD-R-1B CONTROL switch in SGT and verify (VBD-K):

5.3.1 PC-AD-R-1A closed; and

5.3.2 PC-AD-R-1B open.

CAUTION – A vent path must exist prior to unisolating PC to prevent over-pressurization of torus exhaust ventilation ductwork.

NOTE – Following valve opening sequence must be followed to prevent operation of PC-MO-1308 against excessive differential pressure.Ⓡ[1]

5.4 Open PC-MO-1308, TORUS VENT ISOLATION VLV, by placing to OVRD (PNL P2).

5.5 Place PC-MO-305 ISOLATION OVERRIDE to OVERRIDE (Key PA2235) (PNL P2).

5.6 Open PC-MO-305, VALVE MO 230 BYPASS VLV (VBD-H).

5.7 Monitor ERP Effluent radiation (VBD-Q).

ATTACHMENT 2 INFORMATION SHEET

ATTACHMENT 2 INFORMATION SHEET

1. DISCUSSION

1.1 PC venting is restricted, requiring release rates to be kept below Off-Site Dose Assessment Manual radioactive release rate limits.

1.2 Overriding interlocks to vent at PC pressures > 1.84 psig is not permitted in this procedure, since containment pressure may be needed to ensure adequate Core Spray and RHR pump NPSH.

1.3 Suppression Pool water level has a direct effect on the efficiency of the chosen vent path, due to the "scrubbing" effect of the water on fission products. If Suppression Pool level is < 28.5', venting is performed through the torus. However, if Suppression Pool level is ≥ 28.5', venting is performed through the drywell.

1.4 115 Rem/hr is based on not exceeding ODAM release rate limits. The number is derived using EPIP 5.7.16, Release Rate Determination, Section 7, Release Rate Determination Using Drywell Curie Content And Vent Flow Rate. The following assumptions were made to back calculate: 1) Effective Age = 0 hrs, 2) Vent Flow Rate = 319 CFM, 3) Release Rate = 2.87E5 μCi/sec (which is less than the ODAM limit).

2. REFERENCES

2.1 OFF-SITE DOSE ASSESSMENT MANUAL

2.1.1 Section 3.2, Gaseous Effluents.

2.2 PROCEDURES

2.2.1 System Operating Procedure 2.2.9, Core Spray System.

2.2.2 System Operating Procedure 2.2.73, Standby Gas Treatment System.

2.2.3 Emergency Plan Implementing Procedure 5.7.16, Release Rate Determination.

2.2.4 Emergency Operating Procedure 5.8, Emergency Operating Procedures (EOPs).

2.2.5 Emergency Operating Procedure 5.8.20, EOP Plant Temporary Modifications.

2.3 MISCELLANEOUS

2.3.1 Ⓡ[1] NRC IR 90-09, Inspector Follow-Up Open Item (298/9006-01) Corrective Action. Affects CAUTION 2 before Steps 4.1.1 and 5.1.1.

Examination Outline Cross-Reference	Level	SRO
295018 (APE 18) Partial or Complete Loss of CCW / 8 2.4.35 Knowledge of local auxiliary operator tasks during an emergency and the resultant operational effects.	Tier#	1
	Group#	1
	K/A #	295018 G2.4.35
	Rating	4.0
	Revision	0
Revision Statement:		

Question 90

The plant has scrammed from 100% power due to a steam leak in the drywell.

Only REC Pump D is available AND it is running.

A leak that can NOT be isolated has been reported on REC north critical loop.

The following annunciators are ON:

Annunciator	PANEL/WINDOW:
REC SYSTEM LOW PRESSURE	M-1/A-1
REC SURGE TANK LOW LEVEL	M-1/A-3

Procedure 5.2REC [Loss of REC] has been entered.

Which one of the following actions performed by the NLO and related 5.2REC Attachment is required for this situation AND why?

A. Close valve DW-468, REC SURGE TANK LCV-488 ISOLATION to reduce system pressure until the leak can be isolated IAW 5.2REC Attachment 2 [REC Pipe Break].

B. Close REC-18, REC HX B INLET FROM PUMPS C & D and REC-20, REC HX A INLET FROM PUMPS A & B to begin splitting REC critical loops isolated IAW 5.2REC Attachment 5 [Splitting Critical Subsystems].

C. Lift leads in Isolation Relay Cabinets in the Cable Spreading Room to allow opening REC-MO-709, DRYWELL RETURN ISOLATION for restoring DW cooling isolated IAW 5.2REC Attachment 4 [REC Restoration following Isolation].

D. Lift leads in Isolation Relay Cabinets in the Cable Spreading Room to allow closing REC HX Service Water Outlet valves from VBD-M for aligning SW backup to REC IAW 5.2REC Attachment 6 [SW Backup for Critical Subsystem Cooling].

Answer: B
Explanation: The SRO is responsible for selecting and assigning the appropriate Attachment(s) of procedure 5.2REC to mitigate the described condition. REC critical loop cooling is required for CSCS Quad cooling during Modes 1, 2, and 3. For a REC leak, procedure 5.2REC step 4.6 requires performin Attachment 2 [REC Pipe Break]. If the break is on a critical loop (i.e. only one critical loop intact), Att. 2 step 1.6 requires performing Attachment 5 to split REC critical loops. Att. 5 steps 1.5 and 1.6 require locally closing manual valves REC-19 and REC 21 to isolate REC Pumps A and B from REC HX A and to isolate REC Pumps C and D from REC HX B.
Distracters: Answer A is plausible because a sizable REC leak has been reported and 5.2REC Att. 2 requires reducing system pressure to limit leakage until the leak can be isolated. 5,2REC contains local operator actions associated with REC surge tank makeup when annunciator M-1/A-1 [REC System Low Pressure] is on. An examinee may believe automatic makeup to the surge tank should be defeated until the leak is isolated. It is wrong because 5.2REC step 4.7.1 requires additional makeup to the surge tank to be established by opening makeup bypass valve DW-470. System pressure is reduced by stopping all pumps IAW Att. 2 step 1.1 until critical loops are split. Answer C is plausible because there is a steam leak in the drywell, which would cause elevated drywell temperature, and REC Drywell Supply Isolation valves automatically close on low system pressure (<61 psig), after a 40 second time delay. Att. 4 contains steps for restoring REC to DW FCUs. It is wrong because 5.2REC Att. 2 directs closing REC-MO-709, DRYWELL RETURN ISOLATION. Answer D is plausible because it reflects a local operator task listed in 5.2REC. When REC is unable to supply critical loop cooling, procedure 5.2REC subsequent action step 4.8 requires initiating SW backup to REC IAW Attachment 6. SW cools the REC heat exchangers. Establishing SW backup cooling requires isolating the normal SW return path by closing the REC HX outlet valves, SW-MO-650 and SW-MO-651. These valves are interlocked to automatically throttle open upon low system pressure for 40 seconds and will not fully close. 5.2REC Att. 6 step 1.3.2 requires the building operator to lift leads in in Isolation Relay Cabinets A and B in the Cable Spreading Room to allow closing REC HX Service Water Outlet valves using their control switches on VBD-M in the control room. This answer is wrong because this is not required by 5.2REC for the stated conditions. Per TS 3.7.3 bases, one REC pump

provides enough flow to transfer the design heat load during transient or accident conditions.

Technical References: Procedure 5.2REC [Loss of REC](Rev 19), B&R Drawing 2021 Sheet 2 [Reactor Building – Closed Cooling Water System], Alarm Card M-1/A-1 [REC System Low Pressure](Rev 21), Alarm Card M-1/A-3 [REC Surge Tank Low Level](Rev 21)

References to be provided to applicants during exam: none

Learning Objective: INT032-12-06 EO-Q, Given plant condition(s) and the applicable Abnormal/Emergency Procedure, discuss the correct subsequent actions required to mitigate the event(s).

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.43(b)(5)	
Level of Difficulty:	3	

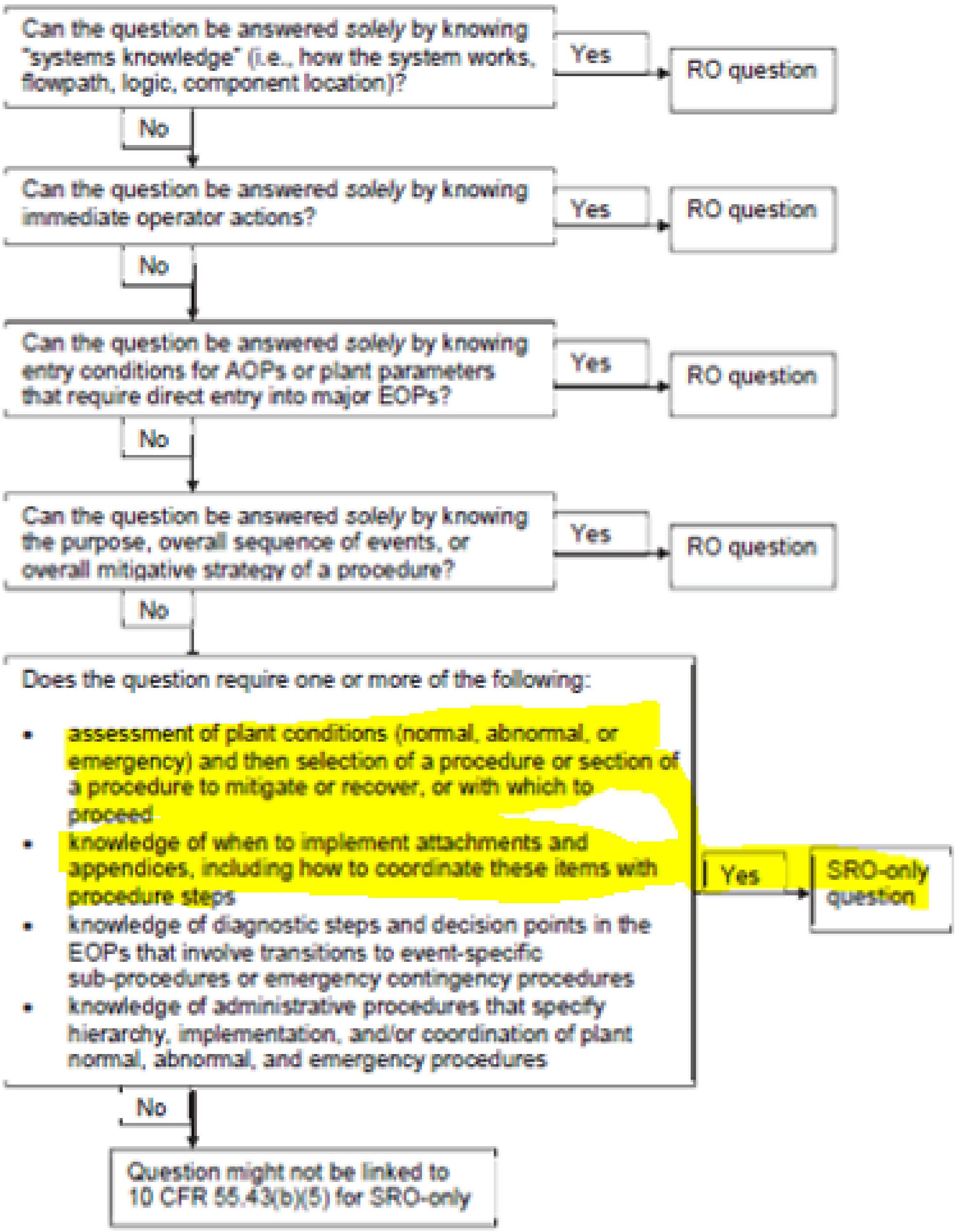
SRO Only Justification:

This question requires assessment of plant conditions and selection of an AOP attachment to mitigate the event. Detailed knowledge of the content of Attachments of procedure 5.2REC is required to make the proper Attachment selection, making this SRO-level.

PSA Applicability:

N/A

**Figure 2-2 Screening for SRO-Only Linked to 10 CFR 55.43(b)(5)
(Assessment and Selection of Procedures)**



C. Facility Licensee Procedures Required To Obtain Authority for Design and Operating Changes in the Facility [10 CFR 55.43(b)(3)]

Some examples of SRO exam items for this topic include the following:

- screening and evaluation processes under 10 CFR 50.59, "Changes, Tests and Experiments"
- administrative processes for temporary modifications
- administrative processes for disabling annunciators
- administrative processes for the installation of temporary instrumentation
- processes for changing the plant or plant procedures

Section IV provides an example of a satisfactory SRO-only question related to this topic.

D. Radiation Hazards That May Arise during Normal and Abnormal Situations, including Maintenance Activities and Various Contamination Conditions [10 CFR 55.43(b)(4)]

Some examples of SRO exam items for this topic include the following:

- process for gaseous/liquid release approvals (i.e., release permits)
- analysis and interpretation of radiation and activity readings as they pertain to the selection of administrative, normal, abnormal, and emergency procedures
- analysis and interpretation of coolant activity, including comparison to emergency plan criteria and/or regulatory limits

SRO-only knowledge should not be claimed for questions that can be answered *solely* based on RO knowledge of radiological safety principles (e.g., radiation work permit requirements, stay time, and DAC hours).

E. Assessment of Facility Conditions and Selection of Appropriate Procedures during Normal, Abnormal, and Emergency Situations [10 CFR 55.43(b)(5)]

This 10 CFR 55.43 topic involves both (1) assessing plant conditions (normal, abnormal, or emergency) and then (2) selecting a procedure or section of a procedure to mitigate or recover, or with which to proceed. One area of SRO-level knowledge (with respect to selecting a procedure) is knowledge of the content of the procedure versus knowledge of the procedure's overall mitigative strategy or purpose.

The applicant's knowledge can be evaluated at the level of 10 CFR 55.43(b)(5) by ensuring that the additional knowledge of the procedure's content is required to correctly answer the written test item. The following are examples:

- knowledge of when to implement attachments and appendices, including how to coordinate these items with procedure steps

- knowledge of diagnostic steps and decision points in the emergency operating procedures (EOPs) that involve transitions to event-specific sub-procedures or emergency contingency procedures

- knowledge of administrative procedures that specify hierarchy, implementation, and/or coordination of plant normal, abnormal, and emergency procedures

SRO-only knowledge should not be claimed for questions that can be answered *solely* using "systems knowledge," such as the following:

- how the system works
- system flowpath
- component locations

SRO-only knowledge should not be claimed for questions that can be answered *solely* using fundamental knowledge of the following:

- the basic purpose of a procedure, the overall sequence of events that will occur, or the overall mitigative strategy of a procedure

- any abnormal operating procedure (AOP) entry condition

- plant parameters that require direct entry into major EOPs (e.g., major Westinghouse EOPs are E0, E1, E2, E3, ECA-0.0, and Red/Orange Functional Restoration and major General Electric EOPs are Reactor Vessel Control, Primary Containment Control, Secondary Containment Control, and Radioactive Release Control)

- immediate operator actions of a procedure

Sections IV and V of this document provide several satisfactory and unsatisfactory examples of test items related to this 10 CFR 55.43(b)(5) topic.

ATTACHMENT 2 REC PIPE BREAK

ATTACHMENT 2 REC PIPE BREAK

1. REC PIPE BREAK

1.1 Stop all REC pumps.

1.2 Close REC-MO-709, DRYWELL RETURN ISOLATION.

1.3 Ensure following valves close:

1.3.1 REC-MO-700.

1.3.2 REC-MO-702.

1.3.3 REC-MO-712.

1.3.4 REC-MO-713.

1.3.5 REC-MO-1329.

1.4 IF Reactor Building accessible, THEN inspect critical loop, including piping between pumps and critical loop supply and return valves.

1.5 IF both critical loops are intact, THEN perform following:

1.5.1 Restart one REC pump.

1.5.2 Open one of following:

1.5.2.1 REC-MO-711, NORTH CRITICAL LOOP SUPPLY.

1.5.2.2 REC-MO-714, SOUTH CRITICAL LOOP SUPPLY.

1.5.3 IF REC surge tank not providing adequate NPSH to REC pumps, THEN initiate service water backup per Attachment 6 (Page 12).

1.6 IF only one critical loop intact, THEN split critical loops per Attachment 5 (Page 10).

4.2 IF low pressure isolation occurred and Annunciator M-1/A-1, REC SYSTEM LOW PRESSURE, cleared, THEN restore system from isolation per Attachment 4 (Page 8).

4.3 **IF REC HEADER PRESSURE not restored after completing Immediate Operator Actions, THEN perform following:**

4.3.1 **SCRAM and enter Procedure 2.1.5.**

4.3.2 Stop both Reactor Recirc pumps and enter Procedure 2.4RR.

4.3.3 Stop running CRD pump.

NOTE – Securing all AC lube oil pumps first will cause DC lube oil pumps to start unless DC oil pump control switches are first taken to STOP and allowed to spring return to their normal positions.

4.3.4 WHEN Recirc MG Sets have stopped, THEN perform following:

4.3.4.1 Momentarily place respective control switches for both DC lube oil pumps to STOP and allow them to spring return to their normal positions (R-958-NW at 125 VDC Reactor Bldg Starter Rack).

4.3.4.2 Shut down all AC lube oil pumps.

Scram Actions

4.4 **IF SW cooling lost to both REC HXs, THEN perform following:**

4.4.1 **SCRAM and enter Procedure 2.1.5.**

4.4.2 Stop both Reactor Recirc pumps and enter Procedure 2.4RR.

NOTE – Securing all AC lube oil pumps first will cause DC lube oil pumps to start unless DC oil pump control switches are first taken to STOP and allowed to spring return to their normal positions.

4.4.3 WHEN Recirc MG Sets have stopped, THEN perform following:

4.4.3.1 Momentarily place respective control switches for both DC lube oil pumps to STOP and allow them to spring return to their normal positions (R-958-NW at 125 VDC Reactor Bldg Starter Rack).

4.4.3.2 Shut down all AC lube oil pumps.

4.4.4 Perform Attachment 1 (Page 5).

Scram Actions

4.5 IF containment pressure rising due to REC loss, THEN vent containment per Procedure 2.2.60.

4.6 IF M-1/A-1, REC SYSTEM LOW PRESSURE, and M-1/A-3, REC SURGE TANK LOW LEVEL, alarming, THEN perform Attachment 2 (Page 6) concurrently with remainder of this procedure.

4.7 IF REC supplying critical loops and M-1/A-3, REC SURGE TANK LOW LEVEL, alarming, THEN perform following:

NOTE – Step 4.7.1 requires Operator to obtain a 10' ladder to reach DW-470.

4.7.1 IF REC surge tank level control valve failed closed, THEN open DW-470, REC SURGE TANK LCV-488 BYPASS, as required (R-976-W above REC surge tank).

NOTE – Cooling to the critical loops is required to be restored within 1 hour to ensure postulated temperature limits are maintained.Ⓟ[6]

4.8 IF critical loop(s) cooling required and REC pumps are unable to supply cooling, THEN perform following prior to CSCS Quad temperatures exceeding 150°F:

4.8.1 If available, initiate service water backup per Attachment 6 (Page 12).

4.8.2 IF CSCS Quad cooling cannot be established, THEN enter Procedure 2.4HVAC.

4.9 IF SW cooling lost to single REC HX, THEN perform following:

4.9.1 If available, place standby REC HX in service per Attachment 3 (Page 7).

4.9.2 Monitor REC HX outlet temperature from REC-TI-452, REC HEADER TEMPERATURE, or PMIS Point M136 if REC-TI-452 not available.

4.9.3 IF REC HX outlet temperature approaches 98°F, THEN reduce REC heat load with one or both of following:

4.9.3.1 Reduce reactor power, as necessary, to maintain REC HX outlet temperature to ≤ 98°F per Procedure 2.1.10.

4.9.3.2 Rapidly remove RWCU from service per Procedure 2.2.66.

4.9.4 IF at any time REC HX outlet temperature cannot be maintained ≤ 98°F, THEN shut down per Procedure 2.1.4.

4.10 IF REC temperature indication not available, REC non-critical loads are in service and a PCIS Group 2 isolation due to a primary coolant leak is present, THEN perform one of following:

4.10.1 Maintain SW flow through REC HX A(B) ≥ 3500 gpm.

4.10.2 Isolate non-critical REC headers.

4.11 IF REC to Non-Regen HX isolated, THEN rapidly remove RWCU from service per Procedure 2.2.66.

4.12 IF REC cooling to FPC HXs lost, THEN enter Procedure 2.4FPC.

SETPOINT	CIC	M-1/A-1
1. (4740) 61 psig	1. REC-PS-452A	
2. (4771) 61 psig	2. REC-PS-452B1	
3. (4772) 61 psig	3. REC-PS-452B2	

PROBABLE CAUSES

- REC pump trip.
- REC line break.

REFERENCES

- Technical Specifications LCO 3.7.3, Reactor Equipment Cooling (REC) System.
- System Operating Procedure 2.2.65.1, REC Operations.
- Emergency Procedure 5.2REC, Loss of REC.

REC SYSTEM LOW PRESSURE	PANEL/WINDOW: M-1/A-1

1. AUTOMATIC ACTIONS

1.1 For REC-PS-452A, REC-MO-700, NON-CRITICAL HEADER SUPPLY; REC-MO-702, DRYWELL SUPPLY ISOLATION; and REC-MO-1329, AUGMENTED RADWASTE SUPPLY, close after a 40 second time delay.

1.2 For REC-PS-452B1, REC-MO-712, HX A OUTLET, closes after a 40 second time delay.

1.3 For REC-PS-452B2, REC-MO-713, HX B OUTLET, closes after a 40 second time delay.

2. OPERATOR OBSERVATION AND ACTION

2.1 If available, start additional REC pumps.

2.2 Ensure REC-MO-711, NORTH CRITICAL LOOP SUPPLY, or REC-MO-714, SOUTH CRITICAL LOOP SUPPLY (associated with an in service HX), open to obtain critical subsystem pressure indication.

2.3 IF REC System header pressure on REC-PI-452, REC HEADER PRESSURE, remains ≤ 62 psig, THEN enter Procedure 5.2REC.

2.4 IF REC HX <u>or</u> Drywell header isolated and restoration desired, THEN take action per REC Restoration Hard Card (2.2.65.1).

REC SURGE TANK LOW LEVEL

PANEL/WINDOW: M-1/A-3

1. OPERATOR OBSERVATION AND ACTION

1.1 Check DW-LCV-488 open.

1.2 IF DW-LCV-488 has failed closed, THEN throttle open DW-470, REC SURGE TANK LCV-488 BYPASS.

1.3 Monitor surge tank for indication of system leakage.

1.3.1 IF level cannot be maintained, THEN enter Procedure 5.2REC.

1.4 Check system for internal leakage.

1.4.1 Check air compressor cooling water SOVs for proper operation.

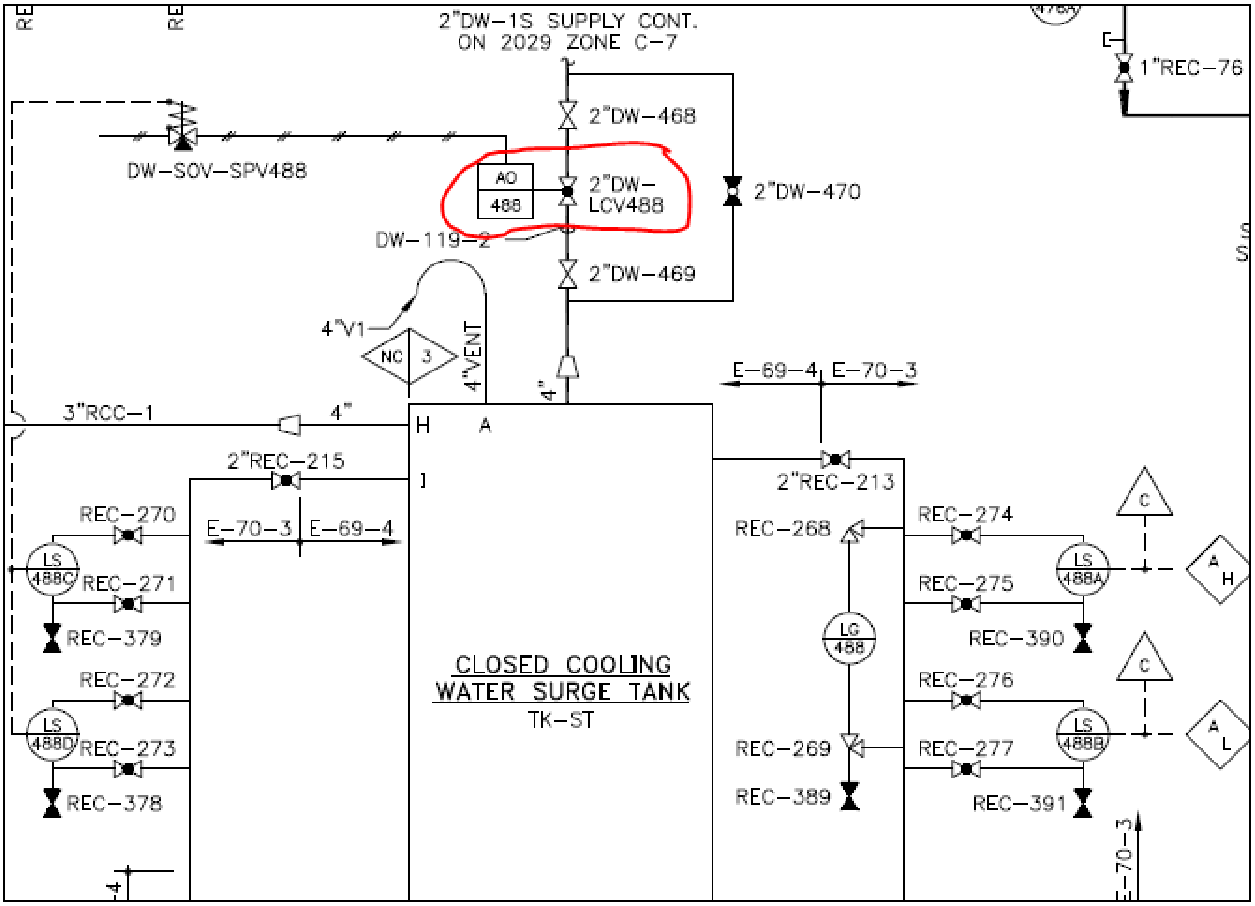
1.4.2 Determine if heat exchanger or cooler leaking:

1.4.2.1 Place standby heat exchangers or coolers in service.

1.4.2.2 Isolate operating heat exchangers or coolers.

1.5 Check system for external leakage.

From B&R Dwg 2021 Sh 2



BASES

APPLICABLE SAFETY ANALYSIS

Either REC loop has sufficient capacity with one pump operating to transfer the essential services design cooling heat load during postulated transient or accident conditions (Ref. 1). However, to provide additional margin, two REC pumps per loop are required to be OPERABLE to satisfy the requirements of the LCO.

Through the intertie with the REC System, the SW System provides essential cooling equivalent to the critical loops of the REC System. The ability of the REC System, or the associated service water supply, to provide adequate cooling to the identified safety equipment is an implicit assumption for the safety analyses evaluated in Reference 1.

The REC System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 2).

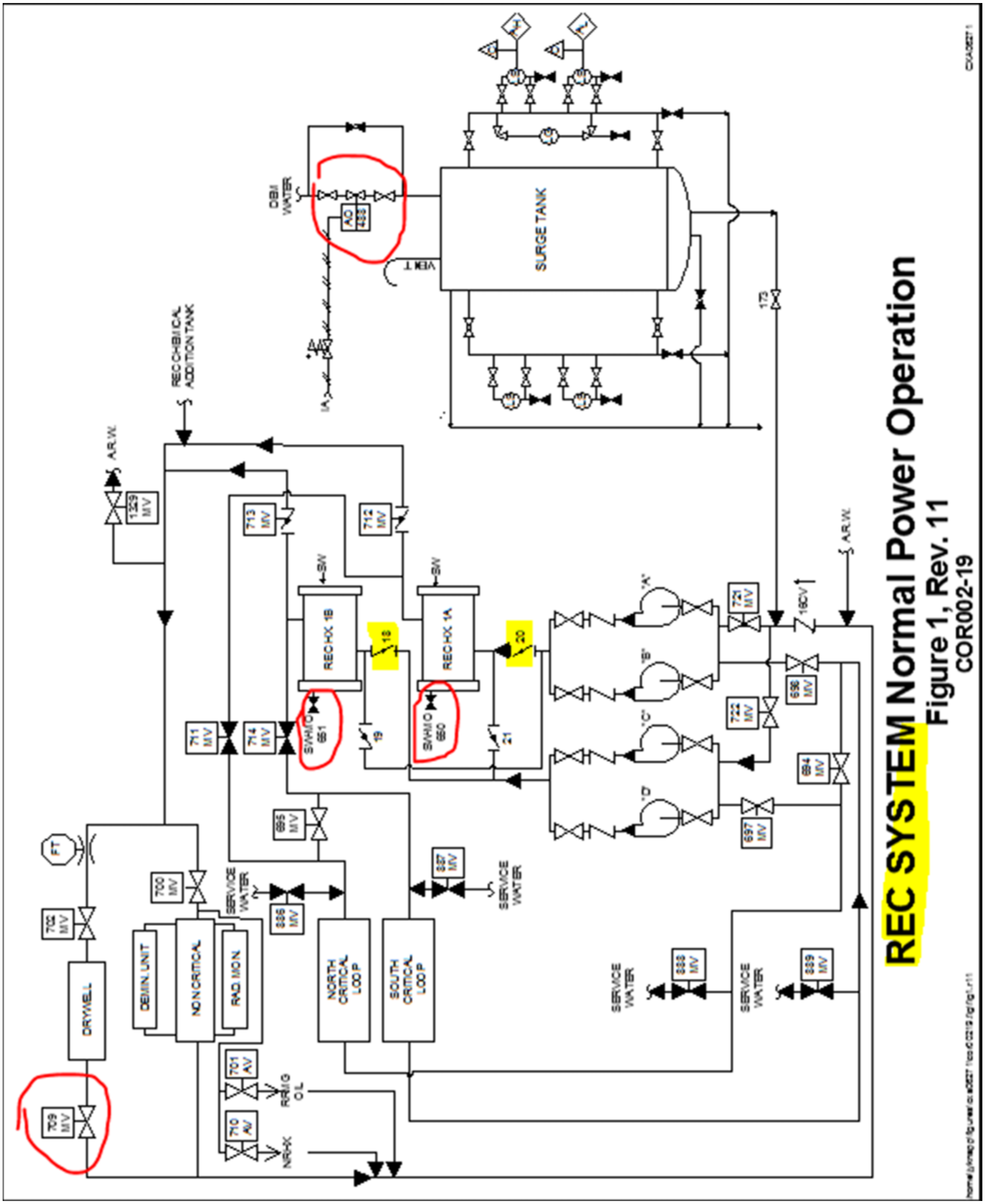
LCO

The REC subsystems are independent of each other to the degree that each has separate controls, power supplies, and the operation of one does not depend on the other. In the event of a DBA, one subsystem of REC is required to provide the minimum heat removal capability assumed in the safety analysis for the system to which it supplies cooling water. To ensure this requirement is met, two subsystems of REC must be OPERABLE. At least one subsystem will operate, if the worst single active failure occurs coincident with the loss of offsite power.

A subsystem is considered OPERABLE when it has two OPERABLE pumps, one OPERABLE heat exchanger, and an OPERABLE flow path capable of transferring the water to the appropriate equipment.

The OPERABILITY of the REC System is based on verifying a maximum supply water temperature of 100°F.

An REC subsystem is considered inoperable if both of the following conditions exits: (1) leakage in excess of allowable limits, and (2) the subsystem of SW backup for the respective REC subsystem is inoperable. The limits are based on having a 30-day supply of inventory in the REC surge tank without crediting makeup. Leakage in excess of limits by itself does not result in either the REC subsystems or the REC system being inoperable. If it is determined that leakage exceeds these limits, then REC is considered degraded and SW backup is required to be OPERABLE to maintain the REC subsystem(s) OPERABLE. An OPERABLE SW backup subsystem requires an OPERABLE flow path from the SW System to the REC critical loops, an OPERABLE SW pump in the respective SW Subsystem, and the ability to align the SW backup valves in the REC System.



REC SYSTEM Normal Power Operation
Figure 1, Rev. 11
COR002-19

Examination Outline Cross-Reference	**Level**	SRO
295019 (APE 19) Partial or Complete Loss of Instrument Air / 8 Ability to determine and/or interpret the following as they apply to PARTIAL OR COMPLETE LOSS OF INSTRUMENT AIR: AA2.02 Status of safety-related instrument air system loads (see AK2.1 - AK2.19)	**Tier#**	1
	Group#	1
	K/A #	295019 AA2.02
	Rating	3.7
	Revision	
Revision Statement:		

Question 91

Reference Provided

The plant is at 10% power.

Instrument Air pressure is completely lost to Reactor Building to Torus Vacuum Breakers.

What TS 3.6.1.7 [Reactor Building-to-Suppression Chamber Vacuum Breakers] ACTION statement is required to be entered?

A. A.1 Close the open Vacuum breaker within 72 hours.

B. B.1 Close one open Vacuum breaker within 1 hour.

C. C.1 Restore the vacuum breaker(s) to OPERABLE status within 72 hours.

D. D.1 Restore all vacuum breakers in one line to OPERABLE status within 1 hour.

Answer: A
Explanation: This question relates to loss of IA as it relates to the Containment function (ref 295019 AK2.09). The Reactor Building to torus vacuum breaker system relieves pressure from the Reactor Building to the torus if torus pressure were to drop to 0.5 psi below Reactor Building pressure. Operation of either vacuum breaker will maintain a pressure differential of less than 2 psid, the external design pressure of containment. The system consists of two separate lines which are open to the Reactor Building atmosphere. They then combine into a common line before going to the torus. Both lines contain a spring-tensioned check valve PC-13CV (PC-14CV), and a 100%

capacity air operated butterfly valve in series PC-AO-243 (PC-AO-244). Each butterfly valve is controlled by a three way switch which is located on Control Room Panel H. When the control switch is in either the OPEN or AUTO position (with a 0.5 psid between Rx Bldg. & Torus), air is vented off the air operator and the valve opens. If the control switch is positioned to CLOSE, air is supplied to the air operator and the valve is held closed. PC-AO-243 and PC-AO-244 are normally closed since RB to Torus dp is normally below 0.5 psid.

On a loss of air pressure or power, PC-AO-243 and PC-AO-244 fail open. This represents one or more lines with one RB to Torus vacuum breaker not closed. Therefore, only TS 3.6.1.7 Action A.1 applies.

Distracters:
Answer B reflects a condition where two vacuum breakers in one line are each open, such that the line is open from Primary Containment to the Reactor Bldg. It is plausible because the system is arranged with parallel piping containing series valves and PC-AO-243 and 244 fail open on a loss of IA. Also, the wording of TS 3.6.1.7 Condition B is complex. It states “One or more lines with two reactor building-to-suppression chamber vacuum breakers not closed.” The examinee who misunderstands the wording of TS 3.6.1.7 Condition B or who believes PC-AO-243 and 244 are in series on the same line may choose this answer. It is wrong because PC-AO-243 and 244 are on separate lines and are each in series with a spring closed check valve that maintains the respective vacuum breaker lines closed, even with PC-AO-243 and 244 failed open..

Answer C is plausible because the system is arranged with parallel piping containing series valves and PC-AO-243 and 244 are air operated, and they are closed during normal, steady-state operation. The examinee who does not remember how PC-AO-243 and 244 fail on a loss of IA and believes they are on the same vacuum breaker line will choose this answer. It is wrong because PC-AO-243 and 244 fail open on loss of IA, and spring check valves PC-13CV and 14 CV will open at the setpoint to provide the required vacuum relief for each vacuum breaker line.

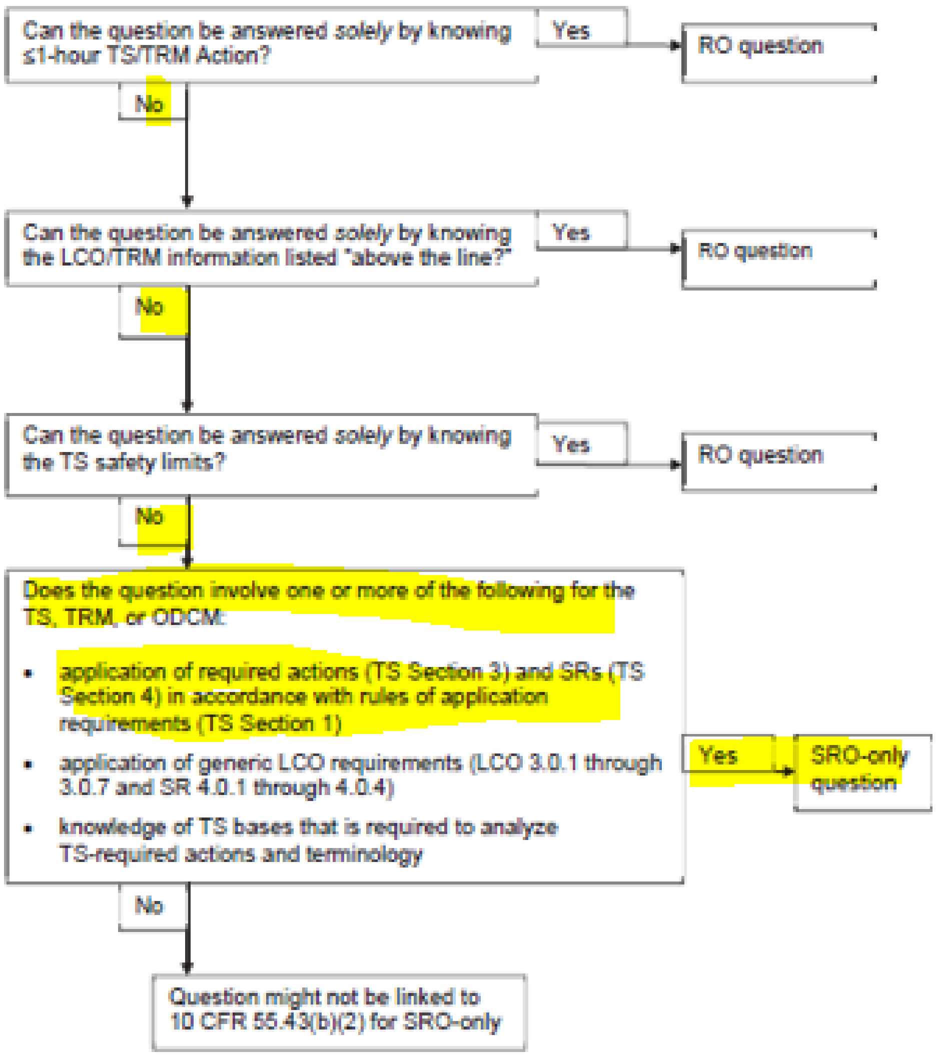
Answer D is plausible because the system is arranged with parallel piping containing series valves and PC-AO-243 and 244 are air operated, and they are closed during normal, steady-state operation. The examinee who does not remember how PC-AO-243 and 244 fail on a loss of IA knows they are on different vacuum breaker lines will choose this answer. It is wrong for the same reason given for distractor C.

Technical References: B&R Dwg 2022 [Primary Containment Cooling & Nitrogen Inerting System] sh 1, TS 3.6.1.7 [Reactor Building-to-Suppression Chamber Vacuum Breakers] and bases, lesson plan COR002-03-02 [Ops Containment](Rev 35)

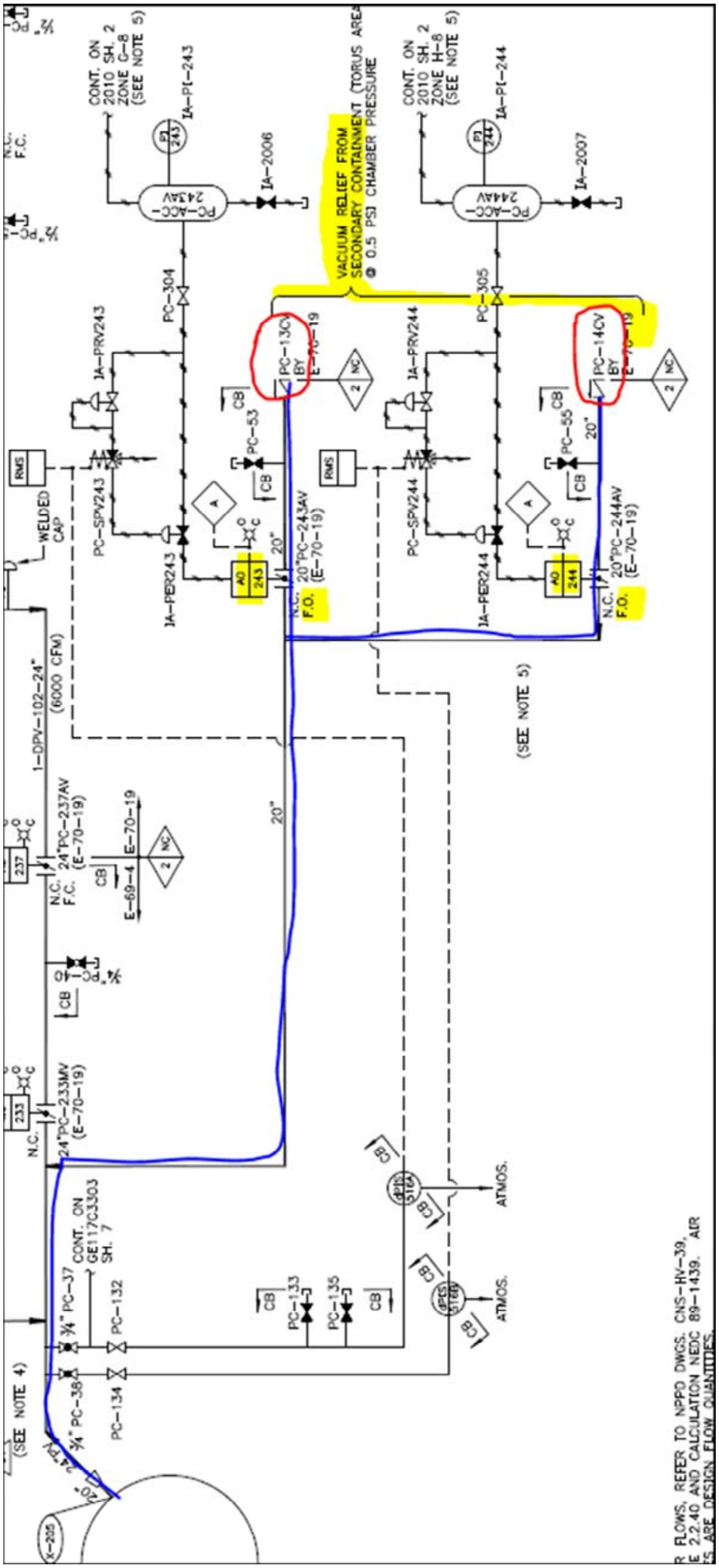
References to be provided to applicants during exam: TS 3.6.1.7 [Reactor Building-to-Suppression Chamber Vacuum Breakers] LCO and ACTIONS, only

Learning Objective: INT007-05-07 EO-3, Given a set of plant conditions that constitutes non-compliance with a Chapter 3.6 LCO, discuss the ACTIONS that are required.		
Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.43(b)(2)	
Level of Difficulty:	3	
SRO Only Justification:		
This question requires application of TS required actions for LCO 3.6.1.7.		
PSA Applicability:		
Top 10 Risk Significant System – Primary Containment		

Figure 2-1 Screening for SRO-Only Linked to 10 CFR 55.43(b)(2) (Technical Specifications)



From B&R Dwg 2022 sh 1



LO-05d
SO-02d

4. Vacuum Relief System

The vacuum relief system is composed of two separate systems. The Reactor Building to torus vacuum breakers and the torus to Drywell vacuum breakers.

Fig 6

a. Reactor Building to Torus Vacuum Breakers

LO-12f
LO-14g

The Reactor Building to torus vacuum breaker system relieves pressure from the Reactor Building to the torus if torus pressure were to drop to 0.5 psi below Reactor Building pressure. Operation of either vacuum breaker will maintain a pressure differential of less than 2 psid, the external design pressure of containment.

The system consists of 2 separate lines which are open to the Reactor Building atmosphere. They then combine into a common line before going to the torus. Both lines contain a spring-tensioned check valve, and a 100% capacity air operated butterfly valve in series. Each butterfly valve is controlled by a three way switch which is located on Control Room Panel H.

The switch positions are:

LO-16e

OPEN - A signal from the control switch causes valve to open.

AUTO - The valve will automatically open upon a differential pressure signal of torus pressure at 0.5 psi less than Reactor Building pressure.

CLOSED - A signal from the control switch causes the valve to close. (This will prevent opening at 0.5 psid.)

When the control switch is in either the OPEN or AUTO position (with a 0.5 psid between Rx Bldg. & Torus), air is vented off the air operator and the valve opens. If the control switch is positioned to CLOSE, air is supplied to the air operator and the valve is held closed. On a loss of air pressure or power, the vacuum breakers fail open. The power supply to the solenoids is 120 VAC CCP 1A, 1B.

Each vacuum breaker has two indicating lights on Panel-H, which are activated by valve position indication switches.

If either of the two vacuum breakers is opened, an annunciator is actuated in the Control Room on Panel H-1.

Each spring-tensioned check valve is self-actuating and operates on differential pressure only. They prevent the Torus from being vented to the Reactor Building in the event that the butterfly valve is opened and torus pressure is higher than Reactor Building pressure. They have no Control Room indication or annunciation.

3.6 CONTAINMENT SYSTEMS

3.6.1.7 Reactor Building-to-Suppression Chamber Vacuum Breakers

LCO 3.6.1.7 Each reactor building-to-suppression chamber vacuum breaker shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

-------------------------------------NOTE-------------------------------------
Separate Condition entry is allowed for each line.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more lines with one reactor building-to-suppression chamber vacuum breaker not closed.	A.1 Close the open vacuum breaker.	72 hours
B. One or more lines with two reactor building-to-suppression chamber vacuum breakers not closed.	B.1 Close one open vacuum breaker.	1 hour
C. One line with one or more reactor building-to-suppression chamber vacuum breakers inoperable for opening.	C.1 Restore the vacuum breaker(s) to OPERABLE status.	72 hours

(continued)

Reactor Building-to-Suppression Chamber Vacuum Breakers
3.6.1.7

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. Two lines with one or more reactor building-to-suppression chamber vacuum breakers inoperable for opening.	D.1	Restore all vacuum breakers in one line to OPERABLE status.	1 hour
E. Required Action and Associated Completion Time not met.	E.1	Be in MODE 3.	12 hours
	<u>AND</u>		
	E.2	Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.7 Reactor Building-to-Suppression Chamber Vacuum Breakers

BASES

BACKGROUND

The function of the reactor building-to-suppression chamber vacuum breakers is to relieve vacuum when primary containment depressurizes below reactor building pressure. If the drywell depressurizes below reactor building pressure, the negative differential pressure is mitigated by flow through the reactor building-to-suppression chamber vacuum breakers and through the suppression-chamber-to-drywell vacuum breakers. The design of the external (reactor building-to-suppression chamber) vacuum relief system consists of four vacuum breakers (two parallel sets of 100% capacity vacuum breaker pairs, each set consisting of a self actuating vacuum breaker and an air-operated vacuum breaker), located in two lines. The air-operated vacuum breakers are actuated by differential pressure switches and can be remotely operated from the control room. The self actuating vacuum breakers function similar to check valves. The four vacuum breakers must be closed to maintain a leak tight primary containment boundary.

A negative differential pressure across the drywell wall is caused by rapid depressurization of the drywell. Events that cause this rapid depressurization are cooling cycles, inadvertent primary containment spray actuation, and steam condensation in the event of a primary system rupture. Reactor building-to-suppression chamber vacuum breakers prevent an excessive negative differential pressure across the primary containment boundary. Cooling cycles result in minor pressure transients in the drywell, which occur slowly and are normally controlled by heating and ventilation equipment. Inadvertent spray actuation results in a more significant negative pressure transient and is important in sizing the external (reactor building-to-suppression chamber) vacuum breakers.

Each series of vacuum breakers is sized on the basis of the air flow from the secondary containment that is required to mitigate the depressurization transient and limit the maximum negative containment (suppression chamber) pressure to within design limits. The maximum depressurization rate is a function of the primary containment spray flow rate and temperature and the assumed initial conditions of the suppression chamber atmosphere.

(continued)

BASES

ACTIONS (continued)

A.1

With one or more lines with one vacuum breaker not closed, the leak tight primary containment boundary may be threatened. Therefore, the inoperable vacuum breakers must be restored to OPERABLE status or the open vacuum breaker closed within 72 hours. The 72 hour Completion Time is consistent with requirements for inoperable suppression chamber-to-drywell vacuum breakers in LCO 3.6.1.8, "Suppression Chamber-to-Drywell V.cuum Breakers." The 72 hour Completion Time takes into account the redundant capability afforded by the remaining breakers, the fact that the OPERABLE breaker in each of the lines is closed, and the low probability of an event occurring that would require the vacuum breakers to be OPERABLE during this period.

B.1

With one or more lines with two vacuum breakers not closed, primary containment integrity is not maintained. Therefore, one open vacuum breaker must be closed within 1 hour. This Completion Time is consistent with the ACTIONS of LCO 3.6.1.1, "Primary Containment," which requires that primary containment be restored to OPERABLE status within 1 hour.

C.1

With one line with one or more vacuum breakers inoperable for opening, the leak tight primary containment boundary is intact. The ability to mitigate an event that causes a containment depressurization is threatened if one or more vacuum breakers in at least one vacuum breaker penetration are not OPERABLE. Therefore, the inoperable vacuum breaker must be restored to OPERABLE status within 72 hours. This is consistent with the Completion Time for Condition A and the fact that the leak tight primary containment boundary is being maintained.

(continued)

Reactor Building-to-Suppression Chamber Vacuum Breakers
B 3.6.1.7

BASES

ACTIONS (continued)

D.1

With two lines with one or more vacuum breakers inoperable for opening, the primary containment boundary is intact. However, in the event of a containment depressurization, the function of the vacuum breakers is lost. Therefore, all vacuum breakers in one line must be restored to OPERABLE status within 1 hour. This Completion Time is consistent with the ACTIONS of LCO 3.6.1.1, which requires that primary containment be restored to OPERABLE status within 1 hour.

Examination Outline Cross-Reference	Level	SRO
400000 (SF8 CCS) Component Cooling Water Ability to (a) predict the impacts of the following on the CCWS and (b) based on those predictions, use procedures to correct, control, or mitigate the consequences of those abnormal operation: A2.01 Loss of CCW pump	Tier#	2
	Group#	1
	K/A #	400000 A2.01
	Rating	3.4
	Revision	0
Revision Statement:		

Question 92

Reference Provided

The plant is at 100% power.

At 0000 on 7/1, DG1 is declared inoperable due to a failed surveillance.

At 0100 on 7/1, REC Pump D trips due to a fault in its motor windings.

What is the EARLIEST time Mode 3 is REQUIRED to be entered IAW TS?

A. 1300 on 7/1

B. 1700 on 7/1

C. 1200 on 7/8

D. 1300 on 7/31

Answer: B

Explanation:
Procedure actions to mitigate the subject condition are the correct implementation of the TS requirements. Per TS bases, two REC pumps per loop are required operable for a REC subsystem to be considered operable IAW TS 3.7.3. REC Pumps C and D, associated with subsystem B, are redundant to REC Pumps A and B, associated with subsystem A. For the situation given, REC Pump D must be declared inoperable at 0100. For an unplanned LCO entry, procedure 2.0.11 requires the SRO to verify operability of redundant equipment.

DG1 is a required support system for REC Pumps A and B, which are powered from MCC-K. REC Pump D is powered from MCC-S, which is supported by DG2. With DG1 inoperable, TS 3.8.1 Action B.2 requires declaring required features, supported by the inoperable DG, inoperable when the redundant required features are inoperable and has a completion time of four hours from discovery. For this case, REC Pumps A and B must be declared inoperable 4 hours after REC Pump D is discovered to be inoperable, which was at 0100. Therefore, REC Pumps A and B must be declared operable no later than 0500. With REC Pumps A, B and D inoperable. TS 3.7.3 Condition C must be entered due to both REC subsystems inoperable for reasons other than REC leakage above the limit with no SW backup available. TS 3.7.3 Action C.1 requires being in Mode 3 within 12 hours. 0500 + 12 hrs = 1700 on 7/1.
Distracters: Answer A is plausible for the examinee who does not consider the completion time of four hours for TS 3.8.1 Action B.2 and enters TS 3.7.3 Condition C at the time of REC Pump D trip. It is wrong because entry into TS 3.7.3 Condition C is not required until the completion time for TS 3.8.1 Action B.2 has elapsed. That completion time of 4 hours only begins upon discovery of REC Pump D inoperable at 0100 and expires at 0500. 12 hours from 0500 is 1700 on 7/1. Answer C is plausible to the examinee who does not realize the support function of DG1 with respect to REC and does not apply TS 3.8.1 Action B.2. This answer is reflective of the 7 day completion time for one DG inoperable in Mode 1, plus the 12 hour completion time of TS 3.8.1 Action F.1 to get to Mode 3. It is wrong because Mode 3 is required to be entered earlier IAW TS 3.7.3 due to both REC subsystems inoperable. Answer D is plausible for the same reason given for distractor C. It reflects the 30 day completion time for TS 3.7.3, plus the 12 hour completion time of TS 3.7.3 Action C.1 to get to Mode 3. It is wrong for the same reason stated for distractor C.
Technical References: TS 3.7.3 [REC System] and bases, TS 3.8.1 [AC Sources – Operating] and bases, Procedure 2.0.11 [Entering and Exiting Technical Specification/TRM/ODAM LCO Condition(s)](Rev 44), Lesson Plan COR002-19-03 [OPS Reactor Equipment Cooling](Rev 31), Procedure 5.3AC480 [480 VAC Bus Failure](Rev 52)
References to be provided to applicants during exam: TS 3.7.3 [REC System] LCO and Actions, only (TS page 3.7-6)
Learning Objective: INT007-05-08 EO-2, Discuss the applicable Safety Analysis in the Bases associated with each Chapter 3.7 Specification; EO-3, Given a set of plant conditions that constitutes non-compliance with a Chapter 3.7 LCO, determine the ACTIONS that are required

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.43(b)(2)	
Level of Difficulty:	3	
SRO Only Justification:		
This question requires knowledge of TS bases required to access REC subsystem operability and it involves application of TS 3.8.1 and TS 3.7.3 required actions.		
PSA Applicability:		
Top 10 Risk Significant System - DGs		

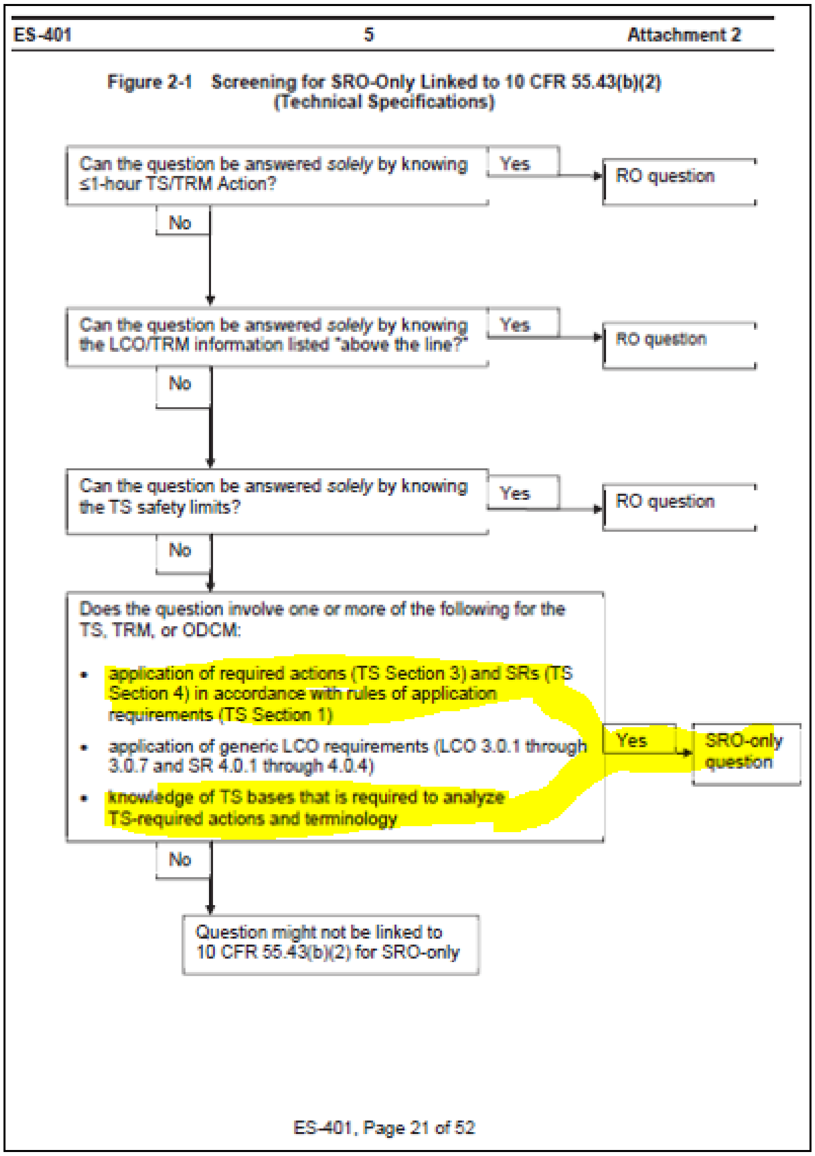

ES-401 5 Attachment 2

Figure 2-1 Screening for SRO-Only Linked to 10 CFR 55.43(b)(2) (Technical Specifications)

ES-401, Page 21 of 52

Lesson Number:	COR002-19-02	Revision: 31

II. **SYSTEM COMPONENTS**

Fig 1, 6, 7
LO-01b,03b,04c
SO-02a,06b

A. REC Pumps

1. The REC system pumps provide the driving force for REC system flow. The pumps' suction is from the critical and non-critical service return headers with the surge tank as a source of makeup water.

LO-02b
SO-09e

2. The four REC pumps are horizontal, centrifugal types, each having a capacity of 33.3%. The pumps' design capacity is 1350 gpm and TDH is 150 ft. The power supplies to the pumps' 75 Hp motors are; MCC-K for pumps IA and IB, and MCC-S for IC and ID.

3. Each REC system pump has a control switch and a mode select switch. The control switch has two positions, START - STOP, and is spring returned to the mid-position. The Normal/Standby switch has two positions, NORMAL and STANDBY.

   The REC system pumps may be started manually by placing the pump=s control switch on Panel M in the START position. The control switch is a spring return to NORMAL type switch. The REC system pumps automatically maintain a pump start seal-in for 0.5 seconds to maintain the REC pump running during a fast transfer of power from normal to startup power, or a momentary power interruption. The REC system pumps will trip if there is a loss of AC power condition for greater than 0.5 seconds.

LO-05c,06d

4. The REC pumps which are selected to STANDBY will restart following a 20 second time delay if power is restored from an emergency source (i.e. DGs or Emergency Transformer). The 20 second time delay is included in the standby start sequence to prevent overloading the emergency power supply. If normal power is restored (Normal or S/U Transformer supplying 4160V Bus 1F/1G) after 0.5 seconds, the REC pumps will not restart automatically, but can be restarted manually.

LO-03e

5. REC pumps 1C and 1D are also controlled from the Alternate Shutdown (ASD) Room. Each pump has a control switch with OFF and RUN positions with light indications for each pump (OFF - Green, RUN - Red) on the REC panel in the ASD room. The REC pump switches in the ASD room will become operable when the REC FLOW INDICATION PUMP C & D Isolation Switch (two positions, NORM and ISOL) is in the ISOL position.

Fig 1, 6, 7
LO-01c,05d
SO-02b

B. REC Heat Exchangers

1. The REC heat exchangers provide the means of transferring the heat from the REC cooling water flow to the SW system.

REC System
3.7.3

3.7 PLANT SYSTEMS

3.7.3 Reactor Equipment Cooling (REC) System

LCO 3.7.3 Two REC subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. REC leakage exceeds limits AND One SW backup subsystem is inoperable	A.1 Verify by administrative means one SW backup subsystem OPERABLE AND A.2.1 Restore the inoperable SW backup subsystem to OPERABLE status. OR A.2.2 Restore REC leakage to within limits.	1 hour 14 days 14 days
B. One REC subsystem inoperable for reasons other than Condition A.	B.1 Restore the REC subsystem to OPERABLE status.	30 days
C. Required Actions and associated Completion Times of Conditions A or B not met. OR Leakage exceeds limits with both SW backup subsystems inoperable OR Both REC subsystems inoperable for reasons other than Condition A.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours

LCO

The REC subsystems are independent of each other to the degree that each has separate controls, power supplies, and the operation of one does not depend on the other. In the event of a DBA, one subsystem of REC is required to provide the minimum heat removal capability assumed in the safety analysis for the system to which it supplies cooling water. To ensure this requirement is met, two subsystems of REC must be OPERABLE. At least one subsystem will operate, if the worst single active failure occurs coincident with the loss of offsite power.

A subsystem is considered OPERABLE when it has two OPERABLE pumps, one OPERABLE heat exchanger, and an OPERABLE flow path capable of transferring the water to the appropriate equipment.

The OPERABILITY of the REC System is based on verifying a maximum supply water temperature of 100°F.

An REC subsystem is considered inoperable if both of the following conditions exits: (1) leakage in excess of allowable limits, and (2) the subsystem of SW backup for the respective REC subsystem is inoperable. The limits are based on having a 30-day supply of inventory in the REC surge tank without crediting makeup. Leakage in excess of limits by itself does not result in either the REC subsystems or the REC system being inoperable. If it is determined that leakage exceeds these limits, then REC is considered degraded and SW backup is required to be OPERABLE to maintain the REC subsystem(s) OPERABLE. An OPERABLE SW backup subsystem requires an OPERABLE flow path from the SW System to the REC critical loops, an OPERABLE SW pump in the respective SW Subsystem, and the ability to align the SW backup valves in the REC System.

INFORMATION ONLY

INFORMATION ONLY

BASES

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.3	Restore offsite circuit to OPERABLE status.	7 days <u>AND</u> 14 days from discovery of failure to meet LCO
B. One DG inoperable.	B.1	Perform SR 3.8.1.1 for OPERABLE offsite circuit(s).	1 hour <u>AND</u> Once per 8 hours thereafter
	<u>AND</u>		
	B.2	Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	<u>AND</u>		
			(continued)

BASES

ACTIONS (continued)

entered concurrently. The "AND" connector between the 7 day and 14 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

Similar to Required Action A.2, the second Completion Time of Required Action A.3 allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of at the time that Condition A was entered.

B.1

To ensure a highly reliable power source remains with one DG inoperable, it is necessary to verify the availability of the offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions must then be entered.

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed to be powered from redundant safety related divisions. Redundant required features failures consist of inoperable features associated with a division redundant to the division that has an inoperable DG.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action the Completion Time only begins on discovery that both:

a. An inoperable DG exists; and

b. A redundant required feature on the other division is inoperable.

If, at any time during the existence of this Condition (one DG inoperable), a redundant required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

3.1.3 Duty SRO shall, using Attachment 5, determine if a separate OPS Hold Clearance Order is required to maintain configuration per Technical Specifications/TRM/ODAM. Ⓟ[9]

3.1.3.1 If OPS Hold Clearance Order required, initiate per Attachment 5.

3.1.4 A second qualified SRO or STE shall provide independent concurrence that the LCO declaration is correct for all new LCO Condition entries. This independent concurrence shall be obtained prior to commencing work which renders the component/system inoperable. Concurrence will include the following: Ⓢ[1,2] Ⓟ[5]

3.1.4.1 All appropriate Tech Spec LCOs are referenced.

3.1.4.2 LCO Condition(s) to be entered or referenced for potential LCO entries. Ⓟ[5]

3.1.4.3 All required actions and completion times are listed in LCO index or Narrative Log.

3.1.4.4 Documented as part of Narrative Log entry made for LCO entry.

3.1.4.5 If a separate OPS Hold Clearance Order is required to control configuration.

3.1.5 Duty SM/CRS declares LCO not met, enters LCO Condition(s), and informs Control Room Staff.

3.1.6 Duty SRO shall track LCO Condition(s) and required action(s) per Section 5.

3.1.7 Go to Step 3.3.

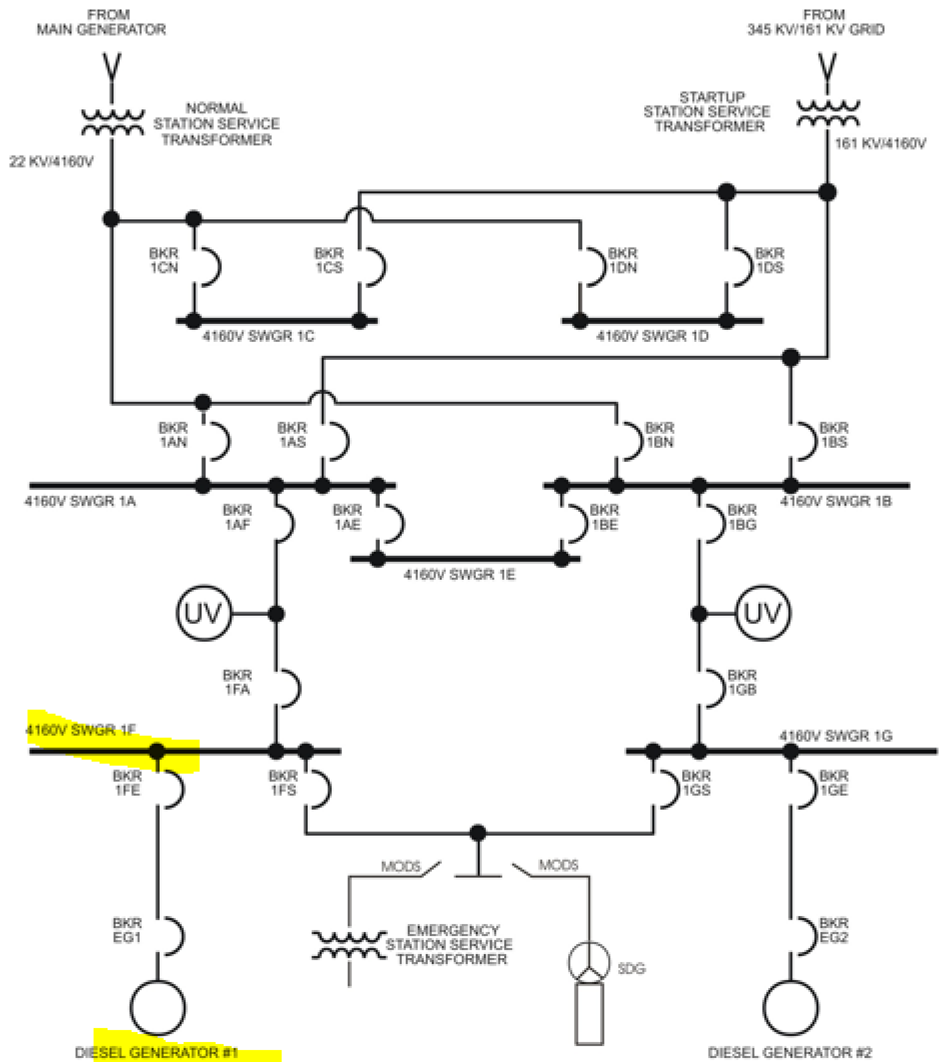
3.2 Enter an Unplanned LCO Condition as follows:

3.2.1 Duty SM/CRS declares component/system/operational parameter inoperable and informs Control Room Staff.

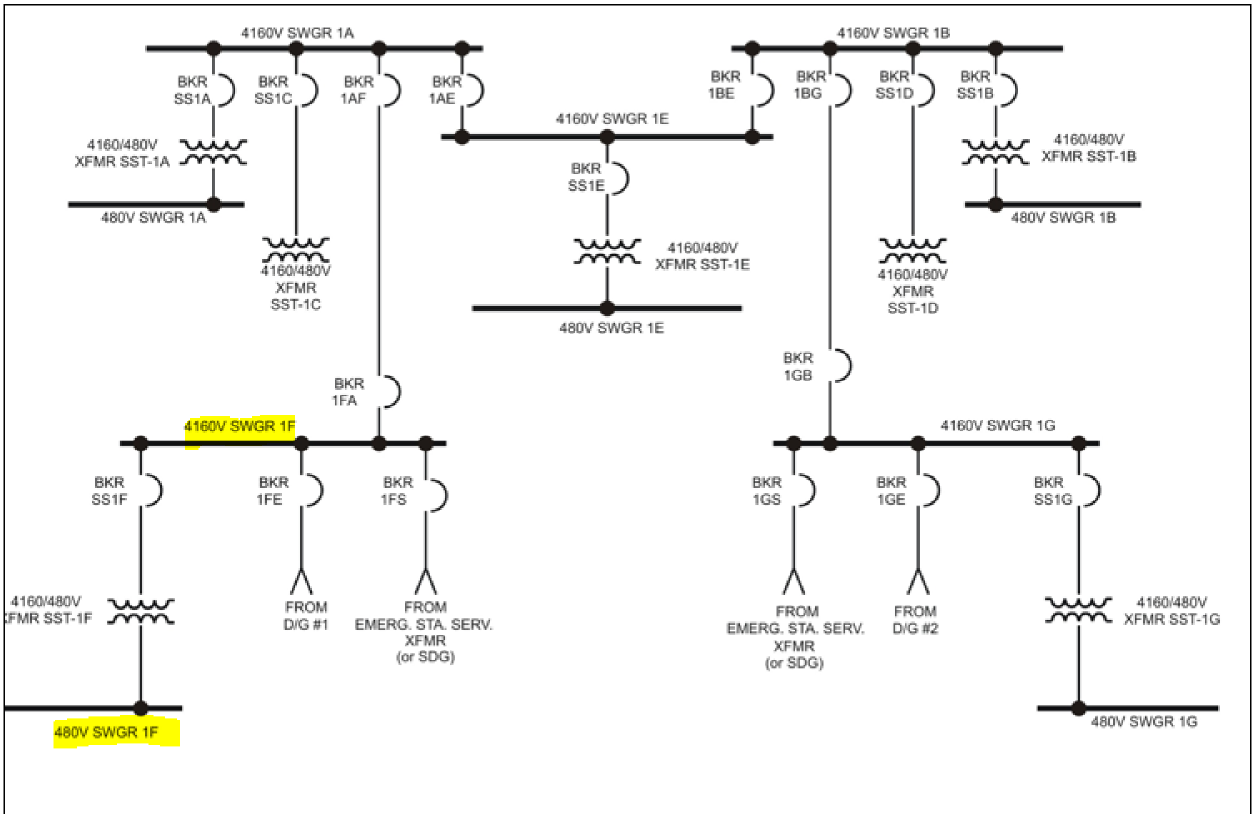
3.2.2 Duty SRO shall ensure verification or demonstration of redundant equipment required to be OPERABLE is performed, as required. Verification should include a review of open LCO Tracking Records and Narrative Log entries for Active and Potential LCO Conditions, and related support/supported system status. Ⓟ[5]

3.2.3 Duty SRO shall ensure Safety Function Determination is performed, as required, per Procedure 2.0.11.1.

3.2.4 Duty SRO shall determine whether a LCO Condition(s) is required to be entered and the required action(s) for the condition(s).



4160V DISTRIBUTION SYSTEM
Figure 4, Rev. 10
COR001-01



480V DISTRIBUTION SYSTEM
Figure 5, Rev. 10
COR001-01

ATTACHMENT 9 480V BUS 1F - MAJOR LOADS

ATTACHMENT 9 480V BUS 1F - MAJOR LOADS

LOADS	NOTES
480V BUS 1F	
MCC-CA	
MCC-K	Causes loss of MCC-Q, MCC-R, and MCC-RA.
MCC-L	
MCC-LX	
MCC-M	
MCC-N	
MCC-P	Causes loss of MCC-RX.
MCC-OG1	Causes loss of MCC-OG2.
CRD Pump 1A	
SAC 1A	
MCC-CA	
Starter Rack HV-STRR-ECBHI	
Control Power Panel A CP-CAD-1A	
Div 1 H_2/O_2 Analyzer Pump	
RR-MO-43A RR Pump A Suction	
PC-MO-1304 Torus Dilution Supply Train A	
PC-MO-1306 Drywell Dilution Supply	
RHR-MO-27A RHR A Outboard Injection	
MCC-K	
MCC-Q	
PC-MO-305 Bypass For PC-MO-230	
Reactor Building Floor Drain Sump Pumps 1A1 and 1B1	
DG Fuel Oil Transfer Pump 1A	Effects OPERABILITY of DGs.
Core Spray A FCU	
NW QUAD-RHR Room FCU	
Security System	
REC Pumps 1A and 1B	

PROCEDURE 5.3AC480 REVISION 52 PAGE 24 OF 49

MCC-K	
MCC-Q	
PC-MO-305 Bypass For PC-MO-230	
Reactor Building Floor Drain Sump Pumps 1A1 and 1B1	
DG Fuel Oil Transfer Pump 1A	Effects OPERABILITY of DGs.
Core Spray A FCU	
NW QUAD-RHR Room FCU	
Security System	
REC Pumps 1A and 1B	

PROCEDURE 5.3AC480 REVISION 52 PAGE 24 OF 49

Examination Outline Cross-Reference	Level	SRO
259001 (SF2 FWS) Feedwater Ability to (a) predict the impacts of the following on the REACTOR FEEDWATER SYSTEM; and (b) based on those predictions, use procedures to correct, control, or mitigate the consequences of those abnormal conditions or operations: A2.02 Feedwater heater isolation	Tier#	2
	Group#	2
	K/A #	259001 A2.02
	Rating	3.3
	Revision	0
Revision Statement:		

Question 93

The plant is at 90% power with 55 Mlbm/hr core flow.

At 1300, alarm point 3233 Feedwater Heater 5A High Level alarms and the following annunciator is received:

HEATER HIGH LEVEL TRIP	PANEL/WINDOW: A-2/C-6

Procedure 2.4EX-STM [Extraction Steam Abnormal] is entered.

At 1305:

The following annunciator is received:

MOISTURE SEPARATOR A HIGH LEVEL	PANEL/WINDOW: A-2/A-4

AND the following conditions exist:

- Feedwater temperature has lowered 13°F, slowly lowering
- Rod line is 107%, slowly rising

What action is required at 1306?

A. Scram and transition to Procedure 2.1.5 [Reactor Scram].

B. Trip turbine and transition to Procedure 2.2.77 [Turbine Generator].

C. Transition to 2.1.10 [Station Power Changes] and perform rapid power reduction using RR.

D. Transition to 2.1.10 [Station Power Changes] and insert emergency power reduction rods.

Answer: C
Explanation: The conditions given represent a rising level in high pressure FWH 5A, which has resulted in automatic isolation of the FWH and is backing up into Moisture Separator A, resulting in high level. Procedure 2.4EXT-STM subsequent action step 4.1 requires transition to Attachment 1 if Moisture Separator level is high. Attachment 1 step 1.4.1 requires performing a rapid power reduction IAW procedure 2.1.10 if Moisture Separator high level alarm is in with the associated FWH 5 high level trip annunciator in. For a rapid power reduction, Procedure 2.1.10 first requires lowering core flow to 40 Mlbm/hr, if rod line is below 118%. That would lower power to ~60-70%. 2.4EX-STM Attachment 1 step Step 1.3 states if the Moisture Separator high level alarm is in continuously for >4 minutes with the associated FWH 5 high level trip annunciator, to remove the unit from service IAW Att. 1 step 1.5. Since the condition of both annunciators simultaneously in has only existed for 1 minute, the appropriate action is to perform a rapid power reduction by lowering Reactor Recirc flow to attempt to reduce level in Moisture Separator A. Step 1.5.1 requires the operator to first scram, if annunciator 9-5-2/C-4 [TSV & TCV Closure Trip Byp Chan A/B] is clear, indicating that a turbine trip would cause an automatic scram. That alarm is clear when power is ≥29.5% RTP, so the next action is to insert a manual scram.
Distracters: Answer A is plausible because 2.4EX-STM Attachment 1 step Step 1.3 states if the Moisture Separator high level alarm is in continuously for >4 minutes with the associated FWH 5 high level trip annunciator, to remove the unit from service IAW Att. 1 step 1.5. Step 1.5.1 requires the operator to first scram, if annunciator 9-5-2/C-4 [TSV & TCV Closure Trip Byp Chan A/B] is clear, indicating that a turbine trip would cause an automatic scram. That alarm is clear when power is ≥29.5% RTP, so the next action would be to insert a manual scram, if high level in FWH 5A and in Moisture Separator A had existed for >4minutes. This answer is wrong because the high levels have only existed for 1 minute, and 2.4EX-STM requires a rapid power reduction to attempt to reduce the high level in Moisture Separator A and avert a reactor scram and turbine trip. Answer B is plausible for the same reason stated for distractor A and because if annunciator 9-5-2/C-4 was in alarm, 2.4EX-STM Att. 1 step 1.5.1 would be N/A, and step 1.5.2 would be the next action, which requires tripping the turbine and performing procedure 2.2.77 to shut down the main turbine. It is wrong because for the reason stated for distractor A, plus power is >29.5%, which implies 9-5-2/C-4 is clear.

Answer D is plausible because with FW temperature lowering, 2.4EX-STM steps 4.4.2 and 4.4.3 require control rod insertion to maintain rod line <118% or to avoid the Stability Exclusion Region of the Power-To-Flow Map. If core flow was 40 Mlbm/hr, insertion of Emergency Power Reduction Rods would be the next step of a Rapid Power Reduction or, in some situations, to exit the Buffer Region of the Power-To-Flow Map. It is wrong because core flow is 55 Mlbm/hr, so the first step of rapid power reduction is to lower core flow by 15 Mlbm/hr. Also, load line is below 118%.

Technical References: Procedure 2.4EX-STM [Extraction Steam Abnormal](Rev 20), Procedure 2.1.10 [Station Power Changes](Rev 116), Alarm Card 9-5-2/C-4 [TSV & TCV Closure Trip Byp Chan A/B](Rev 49), Alarm Card A-2/C-6 [Heater High Level Trip](Rev 41), Alarm Card A-2/A-4 [Moisture Separator A High Level](Rev 41)

References to be provided to applicants during exam: none

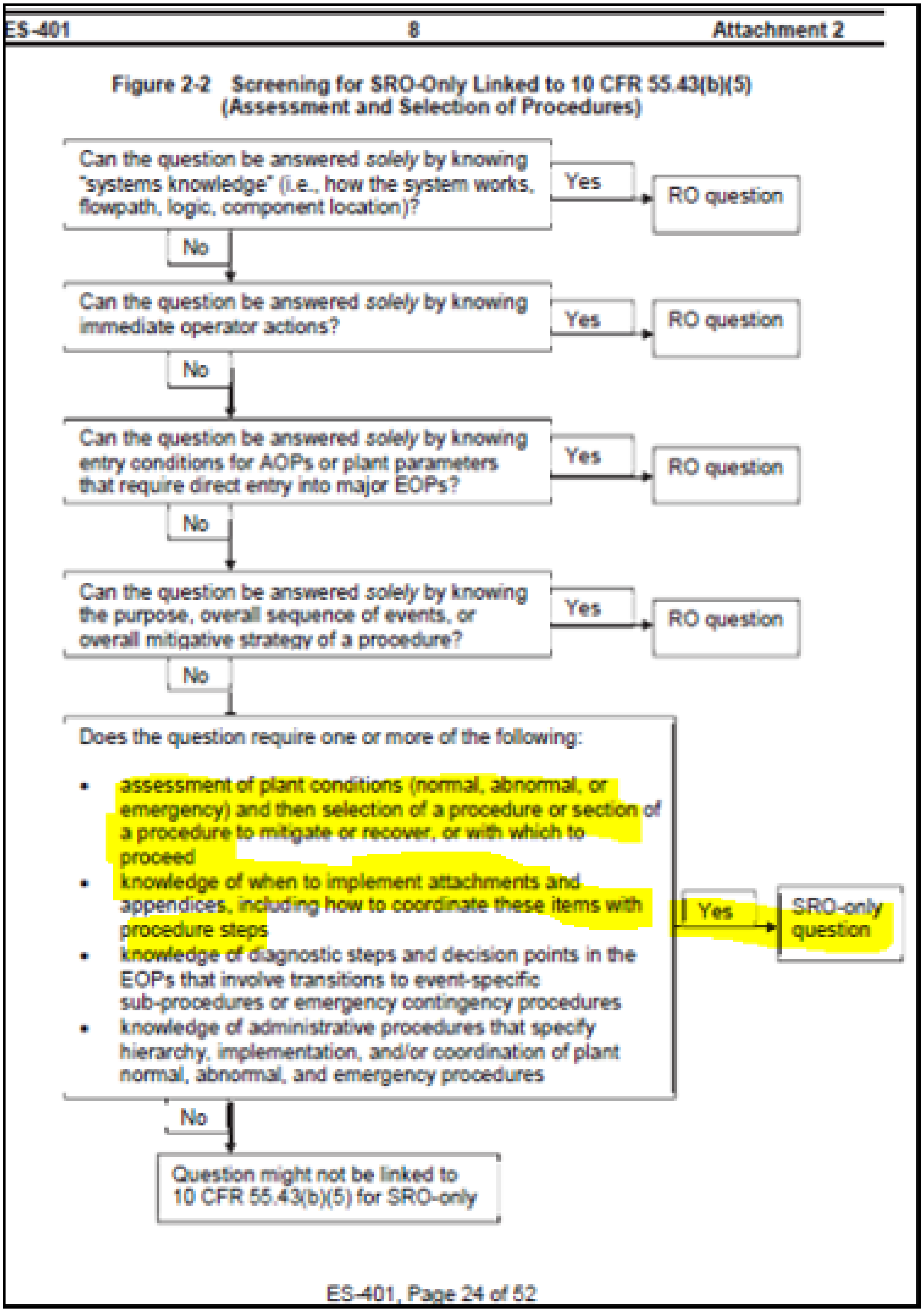
Learning Objective: INT032-01-23 EO-H, Given plant condition(s), state from memory if a manual reactor scram or an emergency shutdown from power is required due to the event(s).

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.43(b)(5)	
Level of Difficulty:	3	
SRO Only Justification:		

This requires evaluation of plant conditions and selection of a procedure/attachment with which to proceed. It also involves knowledge of the content of a procedure attachment versus knowledge of overall mitigative strategy or purpose.

PSA Applicability:

N/A


ES-401
8
Attachment 2
Figure 2-2 Screening for SRO-Only Linked to 10 CFR 55.43(b)(5)
(Assessment and Selection of Procedures)
Can the question be answered *solely* by knowing "systems knowledge" (i.e., how the system works, flowpath, logic, component location)?
Yes
RO question
No
Can the question be answered *solely* by knowing immediate operator actions?
Yes
RO question
No
Can the question be answered *solely* by knowing entry conditions for AOPs or plant parameters that require direct entry into major EOPs?
Yes
RO question
No
Can the question be answered *solely* by knowing the purpose, overall sequence of events, or overall mitigative strategy of a procedure?
Yes
RO question
No
Does the question require one or more of the following:
• assessment of plant conditions (normal, abnormal, or emergency) and then selection of a procedure or section of a procedure to mitigate or recover, or with which to proceed
• knowledge of when to implement attachments and appendices, including how to coordinate these items with procedure steps
• knowledge of diagnostic steps and decision points in the EOPs that involve transitions to event-specific sub-procedures or emergency contingency procedures
• knowledge of administrative procedures that specify hierarchy, implementation, and/or coordination of plant normal, abnormal, and emergency procedures
Yes
SRO-only question
No
Question might not be linked to 10 CFR 55.43(b)(5) for SRO-only
ES-401, Page 24 of 52

C. Facility Licensee Procedures Required To Obtain Authority for Design and Operating Changes in the Facility [10 CFR 55.43(b)(3)]

Some examples of SRO exam items for this topic include the following:

- screening and evaluation processes under 10 CFR 50.59, "Changes, Tests and Experiments"
- administrative processes for temporary modifications
- administrative processes for disabling annunciators
- administrative processes for the installation of temporary instrumentation
- processes for changing the plant or plant procedures

Section IV provides an example of a satisfactory SRO-only question related to this topic.

D. Radiation Hazards That May Arise during Normal and Abnormal Situations, including Maintenance Activities and Various Contamination Conditions [10 CFR 55.43(b)(4)]

Some examples of SRO exam items for this topic include the following:

- process for gaseous/liquid release approvals (i.e., release permits)
- analysis and interpretation of radiation and activity readings as they pertain to the selection of administrative, normal, abnormal, and emergency procedures
- analysis and interpretation of coolant activity, including comparison to emergency plan criteria and/or regulatory limits

SRO-only knowledge should not be claimed for questions that can be answered *solely* based on RO knowledge of radiological safety principles (e.g., radiation work permit requirements, stay time, and DAC hours).

E. Assessment of Facility Conditions and Selection of Appropriate Procedures during Normal, Abnormal, and Emergency Situations [10 CFR 55.43(b)(5)]

This 10 CFR 55.43 topic involves both (1) assessing plant conditions (normal, abnormal, or emergency) and then (2) selecting a procedure or section of a procedure to mitigate or recover, or with which to proceed. One area of SRO-level knowledge (with respect to selecting a procedure) is knowledge of the content of the procedure versus knowledge of the procedure's overall mitigative strategy or purpose.

CNS OPERATIONS MANUAL ABNORMAL PROCEDURE 2.4EX-STM EXTRACTION STEAM ABNORMAL	USE: CONTINUOUS QUALITY: QAPD RELATED EFFECTIVE: 10/2/19 APPROVAL: ITR-RDM OWNER: AOM-SUPPORT DEPARTMENT: OPS

Scram Actions

1. ENTRY CONDITIONS
   1.1 Abnormal Feedwater temperature rise or reduction.
   1.2 Feedwater heater trip.
   1.3 Moisture separator high water level.
   1.4 Feedwater heater bypassed.
   1.5 Main Condensate System flow erratic.
2. AUTOMATIC ACTIONS
   2.1 None.
3. IMMEDIATE OPERATOR ACTIONS
   3.1 IF reactor power rises to > 100% RTP, THEN reduce power to maintain ≤ 100% RTP per Procedure 2.1.10.
4. SUBSEQUENT OPERATOR ACTIONS
   4.1 Record current time and date. Time/Date: ________ / __________
   4.2 IF moisture separator high level, THEN perform Attachment 1 (Page 5).

NOTE – Feedwater temperature indications in Step 4.3 shall be used in the order listed unless inoperable. Operational decisions should not be made using lower order indications (e.g., RR-TR-165) if higher order indications (e.g., PMIS points) are available.

   4.3 Monitor feedwater temperature using following PMIS points (with a quality code of GOOD) or indicators:Ⓟ [2]
      4.3.1 PMIS FEEDWATER HEATING DISPLAY (FWHEAT Turn on Code).
      4.3.2 PMIS Point NSSRP617, FEEDWATER TEMPERATURE.

Scram Actions

ATTACHMENT 1 MOISTURE SEPARATOR HIGH LEVEL

ATTACHMENT 1 MOISTURE SEPARATOR HIGH LEVEL

1. MOISTURE SEPARATOR HIGH LEVEL

1.1 Monitor Main Turbine vibrations on Bearings 3, 4, 5, and 6 (Main Control Room, PANEL B).

1.1.1 **IF unexpected Main Turbine vibration level rise is observed on Bearing 3, 4, 5, or 6, THEN remove unit from service per Step 1.5.**

1.2 Verify all Main Turbine reheat stop valves and interceptor valves open.

1.2.1 **IF any reheat stop valve or interceptor valve closed, THEN remove unit from service per Step 1.5.**

NOTE – Moisture Separators A and C drain to Heater A-5. Moisture Separators B and D drain to Heater B-5.

1.3 **IF moisture separator high level alarm is in continuously for > 4 minutes with associated Number 5 heater High Level Trip, THEN remove unit from service per Step 1.5.**

1.4 IF high level in moisture separator and associated Number 5 heater has High Level Trip, THEN:

1.4.1 Perform rapid power reduction per Procedure 2.1.10 until one of following met:

1.4.1.1 Core flow reaches 40x10[6] lbs/hr.

1.4.1.2 Rod line reaches 118.0%.

1.4.1.3 Moisture separator high level alarm clears.

1.5 **If directed to remove unit from service:**

1.5.1 **IF Annunciator 9-5-2/C-4 clear, THEN SCRAM and enter Procedure 2.1.5.**

1.5.2 Trip Main Turbine.

1.5.3 IF reactor not scrammed, THEN remove Main Turbine from service per Procedure 2.2.77.

Scram Actions

Scram Actions

4.3.3 Average of following PMIS points:

4.3.3.1 B030, REACTOR FW CHNL B1 TEMP.

4.3.3.2 B031, REACTOR FW CHNL A1 TEMP.

4.3.3.3 B032, REACTOR FW CHNL B2 TEMP.

4.3.3.4 B033, REACTOR FW CHNL A2 TEMP.

4.3.4 RF-TI-1, RFP DISCH HDR TEMP (Board A).

4.3.5 RR-TR-165, RR SUCTION & FEEDWATER TEMP (Panel 9-4).

4.4 IF feedwater temperature lowering, THEN monitor APRMs for power rise.

4.4.1 Reduce power with recirculation flow per Procedure 2.1.10, as necessary, to restore power to level it was before feedwater temperature lowered.

4.4.2 Insert control rods per Procedure 10.13 to maintain rod line < 118%.

4.4.3 Insert control rods per Procedure 10.13 to avoid Stability Exclusion Region on Power-To-Flow Map.

NOTE – Reactor power should be monitored using multiple diverse indications. ®[2]

4.4.4 Trend feedwater temperature and reactor power operating point on Attachment 2 (Page 7).

4.4.4.1 **IF operating in UNANALYZED REGION, THEN SCRAM and enter Procedure 2.1.5.**

4.4.4.2 IF operating below NORMAL FEEDWATER HEATING REGION, THEN perform following:

a. Restore feedwater temperature to within region within 2 hours.

NOTE – Completion of the requirement to "lower reactor power to < 25% RTP within the next 4 hours" is not required if feedwater temperature has been restored to NORMAL FEEDWATER HEATING REGION.

b. IF feedwater temperature cannot be restored to NORMAL FEEDWATER HEATING REGION within 2 hours, THEN lower reactor power to < 25% RTP within the next 4 hours per Procedure 2.1.4.3.

Scram Actions

Scram Actions

SETPOINT	CIC	9-5-2/C-4
136.6 psig HP turbine inlet pressure < 29.5% RTP as measured by HP turbine inlet pressure (Tech Spec < 29.5% RTP/171.2 psig):		
1. (2704) TSV & TCV CLOSURE TRIP BYPASSED CHAN A1	1. MS-PS-14A	
2. (2705) TSV & TCV CLOSURE TRIP BYPASSED CHAN A2	2. MS-PS-14C	
3. (2706) TSV & TCV CLOSURE TRIP BYPASSED CHAN B1	3. MS-PS-14B	
4. (2707) TSV & TCV CLOSURE TRIP BYPASSED CHAN B2	4. MS-PS-14D	

PROBABLE CAUSES

- Lowering reactor power (i.e., reactor shutdown).

REFERENCES

- Technical Specification LCO 3.3.1.1, Reactor Protection System (RPS) Instrumentation.

ATTACHMENT 2 RAPID POWER REDUCTION HARD CARD

ATTACHMENT 2 RAPID POWER REDUCTION HARD CARD

1. RAPID POWER REDUCTION

NOTE – Power reduction may be stopped at any point when determined to be no longer needed.

1.1 IF power change is going to be > 10% and OWC Injection System operating in Operator Flow Control Mode, THEN place OWC INJECTION SYS ENABLE switch to SHUTDOWN (Panel A).

CAUTION – When reducing core flow from high power, rod line could exceed 118.0%.

NOTE 1 – If conditions exist where RR flow reduction cannot be reduced rapidly, rod insertion per Section 9 may be required.

NOTE 2 – Core flow reduction may result in entry into LCO 3.4.1 due to recirculation loop flow mis-match.

1.2 While monitoring rod line and feedwater flow, reduce core flow to 40×10^6 lbs/hr using Reactor Recirculation.

1.2.1 IF RRMG is being controlled locally, THEN operate per Procedure 2.4RR.

1.2.2 Before rod line exceeds 118.0%, go to Section 9.

1.3 WHEN core flow is ~ 40×10^6 lbs/hr, THEN go to Section 9 and perform remaining applicable steps of rapid power reduction.

9.5 Reduce rod line to < 70% by performing following:

9.5.1 Insert Emergency Power Reduction Rods per Procedure 10.13.

9.5.2 WHEN feedwater flow is 4.5×10^6 to 8.5×10^6 lbs/hr, THEN secure one RFP by performing following:

9.5.2.1 At any RVLC/RFPT HMI on RFPT-1A(1B) MAIN CONTROL screen, place RFPT controller to be removed from service in MDEM.

9.5.2.2 Slowly lower speed of RFPT being removed from service using UP/DOWN arrows on RFPT-1A(1B) controller.

9.5.2.3 Check speed of operating RFPT rises to maintain RPV level.

9.5.2.4 Ensure minimum flow valve for RFP being removed from service opens.

a. RFP A - RF-FCV-11A, MINIMUM FLOW.

b. RFP B - RF-FCV-11B, MINIMUM FLOW.

9.5.2.5 WHEN discharge pressure for RFPT being removed from service is less than RPV pressure, THEN press RFPT A(B) TURBINE TRIP button (Panel A) and check RFPT A(B) speed drops.

9.5.2.6 At Panel A, close RF-MO-29(30), RFP A(B) DISCHARGE VLV.

12. OPERATION IN BUFFER REGION

NOTE – GARDEL stability cases take ~ 15 minutes to run.

12.1 IF operation in buffer region around Stability Exclusion Region, THEN perform following:

NOTE 1 – The GARDEL stability monitor can be determined to be functioning by observing the STABILITY SUMMARY display in lower left of the main GARDEL graphical user interface. The date, time, and global and regional decay ratio values will update every 10 to 15 minutes after entering and during operation in the buffer region.

NOTE 2 – Normally GARDEL will provide a printout stating that an entry into the stability buffer region has been detected and that a stability case has started. Not receiving a printout does not necessarily reflect a problem with the stability monitor.

12.1.1 Review Stability Summary generated by GARDEL.

12.1.1.1 IF GARDEL stability monitor is not functioning, THEN perform following:

a. Immediately exit buffer region by performing one of following:

1. Raise speed of operating recirculation pump(s) per Section 6.

2. Insert Emergency Power Reduction Rods per Procedure 10.13.

b. Contact Reactor Engineering.

12.1.2 IF global decay ratio is > 0.80, THEN exit buffer region by performing one of following:

12.1.2.1 Raise speed of operating recirculation pump(s) per Section 6.

12.1.2.2 Insert Emergency Power Reduction Rods per Procedure 10.13.

12.1.3 IF global decay ratio is between 0.50 and 0.80 (inclusive) and regional decay ratio is higher than global decay ratio, THEN exit buffer region by performing one of following:

12.1.3.1 Raise speed of operating recirculation pump(s) per Section 6.

12.1.3.2 Insert Emergency Power Reduction Rods per Procedure 10.13.

13. RECORDS

13.1 No quality records generated by this procedure.

SETPOINT	CIC	A-2/C-5
Relay operation caused by:		
1. (3220) 20" below Heater A-5 centerline	1. CD-LS-60A	
2. (3219) 21" below Heater A-4 centerline	2. CD-LS-61A	
3. (3218) 20" below Heater A-3 centerline	3. CD-LS-62A	
4. (3217) 15" below Heater A-2 centerline	4. CD-LS-63A	
5. (3216) 26 7/8" below Heater A-1 centerline	5. CD-LS-64A	
6. (3225) 20" below Heater B-5 centerline	6. CD-LS-65A	
7. (3224) 21" below Heater B-4 centerline	7. CD-LS-66A	
8. (3223) 20" below Heater B-3 centerline	8. CD-LS-67A	
9. (3222) 15" below Heater B-2 centerline	9. CD-LS-68A	
10. (3221) 26 3/4" below Heater B-1 centerline	10. CD-LS-69A	

PROBABLE CAUSES

- Changing power levels.
- Level control valve malfunction.
- Heater tube leak.

REFERENCES

- Ⓟ[1] RICSIL 031. Affects Step 1.4.
- System Operating Procedure 2.2.29, Feedwater Heaters and Extraction Steam System.
- Abnormal Procedure 2.4EX-STM, Extraction Steam Abnormal.

HEATER HIGH LEVEL	PANEL/WINDOW: A-2/C-5

1. OPERATOR OBSERVATION AND ACTION

NOTE – Heater levels may be viewed from outside Heater Bay via cameras.

1.1 Check affected heater level at IR-1A or IR-1B.

1.2 Check affected heater level locally in the Heater Bay, as required.

1.3 Check applicable heater-to-heater and heater-to-condenser valves (CD-AO-LCV) are fully open.

HEATER	VALVES	POSITION
A-1	CD-AO-LCV64	OPEN
A-2	CD-AO-LCV63A and CD-AO-LCV63B	OPEN
A-3	CD-AO-LCV62A and CD-AO-LCV62B	OPEN
A-4	CD-AO-LCV61A and CD-AO-LCV61B	OPEN
A-5	CD-AO-LCV60A and CD-AO-LCV60B	OPEN
B-1	CD-AO-LCV69	OPEN
B-2	CD-AO-LCV68A and CD-AO-LCV68B	OPEN
B-3	CD-AO-LCV67A and CD-AO-LCV67B	OPEN
B-4	CD-AO-LCV66A and CD-AO-LCV66B	OPEN
B-5	CD-AO-LCV65A and CD-AO-LCV65B	OPEN

1.4 Check RF-TI-1, RFP DISCH HDR TEMP, indicator for a loss of feedwater heating and enter Procedure 2.4EX-STM, if required. Ⓟ[1]

1.5 Check Condensate System flow to determine if heater tube leak exists.

1.6 Adjust heater levels per Procedure 2.2.29, as necessary.

SETPOINT	CIC	A-2/A-4
(3200) 10 1/2"	CD-LS-58	

PROBABLE CAUSES

- Power level changes.
- Heater LCV failure.

REFERENCES

- Annunciator 9-5-2/C-4, TSV & TCV CLOSURE TRIP BYP CHAN A/B.
- ⓟ[1] CR-CNS-2003-03693, Corrective Action 16 Closure Report. Affects Step 1.3.
- ⓟ[2] SCR 2003-1432, Reactor Transient Caused by Loss of Feedwater Heating. Affects Step 1.1.1.
- General Operating Procedure 2.1.5, Reactor Scram.
- General Operating Procedure 2.1.10, Station Power Changes.
- System Operating Procedure 2.2.77, Turbine Generator.
- Abnormal Procedure 2.4EX-STM, Extraction Steam Abnormal.

MOISTURE SEPARATOR A HIGH LEVEL

PANEL/WINDOW: A-2/A-4

1. OPERATOR OBSERVATION AND ACTION

1.1 Monitor Main Turbine vibrations on Bearings 3, 4, 5, and 6.

1.1.1 **IF unexpected Main Turbine vibration level rise is observed on Bearing 3, 4, 5, or 6, THEN remove unit from service per Step 1.4.** Ⓟ[2]

1.2 Verify all Main Turbine reheat stop valves and interceptor valves open.

1.2.1 **IF any reheat stop valve or interceptor valve closed, THEN remove unit from service per Step 1.4.**

1.3 **IF Moisture Separator high level alarm is in continuous for > 4 minutes with a Heater A-5 High Level Trip, THEN remove unit from service per Step 1.4.** Ⓟ[1]

1.4 **IF directed to remove unit from service, THEN perform following:**

1.4.1 **IF Annunciator 9-5-2/C-4 clear, THEN SCRAM and enter Procedure 2.1.5.**

1.4.2 Trip Main Turbine.

1.4.3 IF reactor not scrammed, THEN enter Procedure 2.2.77.

1.5 IF high level in Moisture Separator and Heater A-5 has a High Level Trip, THEN perform following:

1.5.1 Perform rapid power reduction per Procedure 2.1.10 until Moisture Separator High Level Alarm clears.

1.5.2 Enter Procedure 2.4EX-STM.

NOTE – If only Moisture Separator A has high level alarm, with CD-MO-64 open and High Level Trip alarms clear, level Switch CD-LS-56 is most likely failed.

1.6 Ensure CD-MO-64, MOISTURE SEPARATOR A DRAIN TO HEATER A-5, is open on LR-102 (T-903-Corridor).

Scram Actions

Scram Actions

Examination Outline Cross-Reference	Level	SRO
2.4.42 Ability to recognize system parameters that are entry-level conditions for Technical Specifications.	Tier#	3
	Group#	
	K/A #	G2.4.42
	Rating	4.6
	Revision	
Revision Statement:		

Question 94

At 0800, an I&C surveillance for a pressure switch associated with one channel in a one-out-of-two-taken twice logic system is started.

The surveillance has a 6 hour Delayed Entry Time (DET).

The TS allowable value for the function is ≤ 10 psig.

At 1000, the channel tripped per the surveillance (as-found setpoint) at 9 psig.

At 1200, I&C reports having trouble getting the cover off of the pressure switch by hand and exit the RCA to obtain a special tool from the warehouse.

IAW procedure 0.26 [Surveillance Program],

What is the EARLIEST time the CONDITIONS and REQUIRED ACTIONS of Technical Specifications are REQUIRED to be entered?

A. 0800

B. 1000

C. 1200

D. 1400

Answer: D
Explanation: The channel under test is considered inoperable when the surveillance is started. However, per TS notes before SRs regarding Delayed Entry Time, when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to the DET, in

this case 6 hours, provided the associated Function maintains trip capability. If one channel of a one-out-of-two-taken twice logic system is removed from service, the remaining channels provide trip capability, so DET is allowed. This allows delaying entry into associated TS Conditions and Required Actions for a maximum of 6 hours from the surveillance start time, 0800. 6 hrs from 0800 is 1400.

None of the other information provided in the stem requires declaring the channel under test inoperable for a reason other than the surveillance.

Distracters:

Answer A is plausible because it is the surveillance start time, which would be correct if a DET was not provided by TS or if trip capability was not maintained by remaining OPERABLE channels. It is wrong because it is not the LATEST time listed, and a DET of 6 hrs applies, since a DET is specified, and other channels are providing the trip function.

Answer B is plausible because it is the time the instrument is tripped. The allowable value given in the stem is common to a "high" setpoint, where the trip function occurs as the parameter rises. Examinees sometimes confuse use of the qualifying signs (i.e ≥ or ≤) stated for TS allowable values with the purpose of the functions themselves. For instance, if asked to list the allowable value for RPS high reactor pressure trip, they sometimes list it as ≥ 1050 psig, since the trip occurs as pressure rises. For the situation given in the stem, an examinee may believe the channel tripped outside of the TS allowable value. If that were true, the channel would be considered inoperable for reasons other than the required surveillance, and associated CONDITIONS and Required Actions would be required to be entered at 1000. It is wrong because the trip setpoint is within the as-found allowable value of the surveillance, and for the reasons stated for distractor A.

Answer C is plausible because it is the time the physical problem with the transmitter is reported. It is wrong because the problem described does not render the channel inoperable for a reason other than the required surveillance and because of the reasons given for distractor A.

Technical References: Procedure 0.26 [Surveillance Program](Rev 71), TS 3.3.1.1 [RPS Instrumentation] (as an example for DET allowances)

References to be provided to applicants during exam: none

Learning Objective: SKL008-01-02 EO-9, Briefly describe the administrative process for the application of DETs during surveillance testing.

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X

Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.43(b)(2)	
Level of Difficulty:	3	
SRO Only Justification:		
This requires application of rules for administration of TS surveillance requirements and action statements.		
PSA Applicability		
N/A		

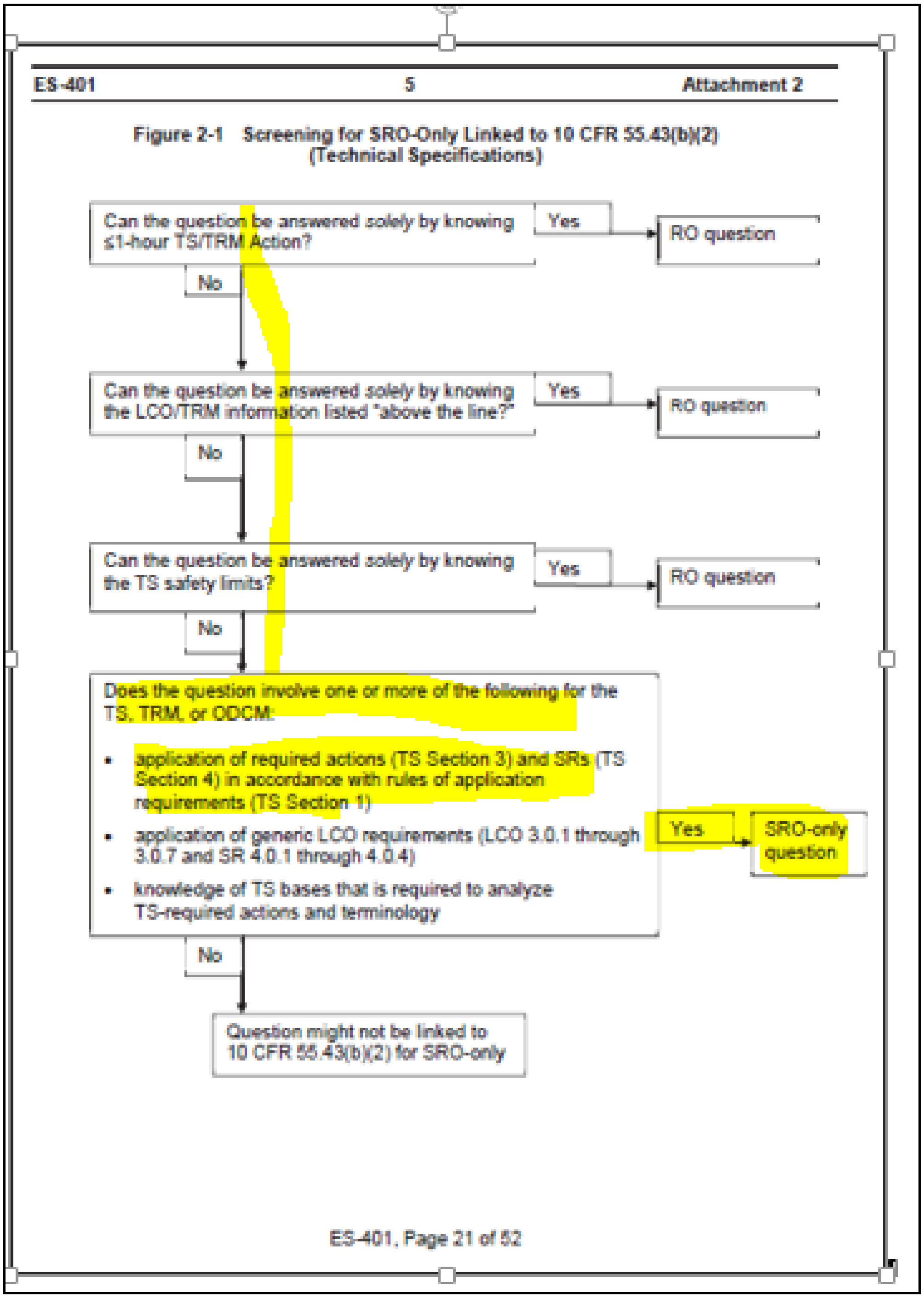


Figure 2-1 Screening for SRO-Only Linked to 10 CFR 55.43(b)(2) (Technical Specifications)

1.6 OPERABILITY DURING SURVEILLANCE TESTING GUIDELINES

1.6.1 Technical Specifications, Technical Requirements Manual, and Off-Site Dose Assessment Manual Surveillance Requirements may have notes that allow delayed entry into Conditions and Required ACTIONs for equipment made inoperable by performance of the surveillance. Even though delayed entry is allowed, the equipment/component is still considered inoperable while performing these surveillances. The delayed entry is only allowed if there is not a loss of function.

1.6.1.1 Restoration of an individual instrument within a Surveillance Procedure, including Independent Verification when required, shall be completed prior to testing another instrument within that Surveillance Procedure. Ⓟ[9]

PROCEDURE 0.26 REVISION 71 PAGE 19 OF 29

RPS Instrumentation
3.3.1.1

SURVEILLANCE REQUIREMENTS

NOTES

1. Refer to Table 3.3.1.1-1 to determine which SRs apply for each RPS Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains RPS trip capability.

Examination Outline Cross-Reference	**Level**	SRO
2.2.38 Knowledge of conditions and limitations in the facility license.	**Tier#**	3
	Group#	
	K/A #	G2.2.38
	Rating	4.5
	Revision	0
Revision Statement:		

Question 95

The plant is at 100% power.

At 1200, the shift complement of NLOs becomes one less than required by TS 5.5.2.a due to an NLO leaving the site due to illness.

(1) Which one of the following is the LATEST time that maintains compliance with the Operating License for the required NLO position to be filled?

AND

(2) If 10 CFR 50.54(x) is invoked due to a condition which prevents filling the NLO position within the required time, which one of the following persons must approve the deviation? **(Assume only persons listed are available, and plant conditions are normal.)**

A. (1) 1255
(2) Shift Manager

B. (1) 1255
(2) AOM-Operating Shift

C. (1) 1355
(2) Shift Manager

D. (1) 1355
(2) AOM-Operating Shift

Answer: D
Explanation:

The NLO staffing requirements are delineated in TS 5.5.2.a. TS 5.5.2.c allows shift crew composition to be less than the minimum requirement of 10 CFR 50.54(m)(2)(i) and Specification 5.2.2.a for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements The condition presented represents a deviation from TS. Procedure 2.0.1 lists the chain-of-command for an on-shift SRO for non-emergency situations as AOM-Operating Shift, Operations Manager, and GMPO (GMPO is the highest in the chain-of-command). 2.0.1 also states prior to taking action, the action shall be approved by highest person in the appropriate chain-of-command (declared event or non-event situation) that is available. Since the stem states Assume only persons listed are available, the AOM-Operating Shift must approve the deviation.
Distracters: Answer A part 1 is plausible because many TS required actions have a 1 hour completion time and because the reporting requirement for part 2 of the question has a 1 hour time limit. It is wrong because it does not reflect the latest time allowed by TS 5.5.2.c (within 2 hours). Part 2 is plausible because the Shift Manager initially acts as Emergency Director during a declared emergency, and procedure 2.0.1 lists the Emergency Director as the highest in the chain-of-command during emergencies. It also states in an emergency, an on-shift SRO may authorize deviation from a license condition (e.g., approved procedures) or Technical Specifications as allowed by 10CFR50.54(x) and (y) or 10CFR72.32(d). It is also plausible because procedure 2.0.1 states that at a minimum, an on-shift SRO must approve the deviation. This answer is wrong because the situation presented is non-emergency with one person higher in the chain-of-command than the SM, the AOM-Operating Shift, available; therefore, the AOM-Operating Shift must approve the deviation. Answer B part 1 is plausible and wrong for the same reason stated for distractor A. Part 2 is correct. Answer C part 1 is correct. Part 2 is plausible and wrong for the same reason stated for distractor A.
Technical References: TS 5.5.2 Organization, Unit Staff; Procedure 2.0.1 [Plant Operations Policy](Rev 66)
References to be provided to applicants during exam: none
Learning Objective: INT032-01-03 EO F.1.d, Discuss the following as described in Procedure 2.0.5, Reports to NRC Operations Center: Instructions section of procedure

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.43(b)(1)	
Level of Difficulty:	3	
SRO Only Justification:		
This question tests knowledge of administrative requirements in the Operating License and reporting requirements for deviations from the Operating License.		
PSA Applicability:		
N/A		

II. Examples of Additional Knowledge and Abilities as They Pertain to an SRO License and the 10 CFR 55.43(b) Topics [ES-401, Section D.1.c]

A. Conditions and Limitations in the Facility License [10 CFR 55.43(b)(1)]

Examples of SRO exam items for this topic include the following:

- reporting requirements when the maximum licensed thermal power output is exceeded
- administration of fire protection program requirements, such as compensatory actions associated with inoperable sprinkler systems and fire doors
- required actions necessary when a facility does not meet the administrative controls listed in Technical Specifications (TS), Section 5 or 6, depending on the facility (e.g., shift staffing requirements)
- National Pollutant Discharge Elimination System requirements, if applicable
- processes for TS and final safety analysis report changes

Note: The analysis and selection of required actions for TS Sections 3 and 4 may be more appropriately listed in the following 10 CFR 55.43 topic.

B. Facility Operating Limitations in the Technical Specifications and Their Bases [10 CFR 55.43(b)(2)]

Some examples of SRO exam items for this topic the following:

- application of required actions (TS Section 3) and surveillance requirements (SR) (TS Section 4) in accordance with rules of application requirements (TS, Section 1)
- application of generic limiting condition for operation (LCO) requirements (LCO 3.0.1 through 3.0.7; SR 4.0.1 through 4.0.4).
- knowledge of TS bases that are required to analyze TS-required actions and terminology
- same items listed above for the Technical Requirements Manual (TRM) and Offsite Dose Calculation Manual (ODCM)

SRO-only knowledge generally cannot be claimed for questions that can be answered *solely* based on knowledge of ≤1 hour action statements and the safety limits since reactor operators (ROs) are typically required to know these items.

5.2.2 Unit Staff

The unit staff organization shall include the following:

a. A non-licensed operator shall be assigned when the reactor contains fuel and two additional non-licensed operators shall be assigned when the reactor is operating in MODES 1, 2, or 3.

(continued)

Cooper 5.0-2 Amendment No. 241

INFORMATION ONLY

INFORMATION ONLY

Organization
5.2

5.2 Organization

5.2.2 Unit Staff (continued)

b. At least one licensed Reactor Operator (RO) shall be present in the control room when fuel is in the reactor. In addition, while the unit is in MODE 1, 2, or 3, at least one licensed Senior Reactor Operator (SRO) shall be present in the control room.

c. Shift crew composition may be less than the minimum requirement of 10 CFR 50.54(m)(2)(i) and Specification 5.2.2.a for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements.

16. 10CFR50.54(x) OR 10CFR72.32(d) DEVIATION FROM LICENSE Ⓟ[5]

NOTE 1 – Only NPPD employees can be considered part of the chain-of-command. The normal chain-of-command for an on-shift SRO is the Assistant Operations Manager - Operating Shift, Operations Manager, and GMPO. If an event has been declared, the chain-of-command for an on-shift SRO is the Emergency Director.

NOTE 2 – The use of 10CFR50.54(x) and (y) or 10CFR72.32(d) is not optional. If an emergency exists and protective action is needed to protect the public health and safety or site personnel, and no action consistent with the operating license or ISFSI general license can provide adequate or equivalent protection, then personnel shall take the protection action under 10CFR50.54(x) and (y) or 10CFR72.32(d).

16.1 In an emergency, an on-shift SRO (or an individual higher in the chain-of-command) may authorize deviation from a license condition (e.g., approved procedures) or Technical Specifications as allowed by 10CFR50.54(x) and (y) or 10CFR72.32(d).

16.3 Implement the action as follows:

16.3.1 Prior to taking action, the action shall be approved by highest person in the appropriate chain-of-command (declared event or non-event situation) that is available. However, an on-shift SRO, at a minimum, must approve the action.

16.3.2 Take specified action.

16.3.3 Make appropriate 10CFR50.72 or 10CFR72.75(b) notification per Procedure 2.0.5.

Examination Outline Cross-Reference	**Level**	SRO
2.4.8 Knowledge of how abnormal operating procedures are used in conjunction with EOPs.	**Tier#**	3
	Group#	
	K/A #	G2.4.8
	Rating	4.5
	Revision	1
Revision Statement: Replaced question with a new one based on NRC CE comment during "free review" that original question did not meet generic requirements for Tier 3.		

Question 96

An event has occurred requiring entry into EOP flowcharts, 2.4 series procedures, 5.1 series procedures, and 5.8 series procedures.

According to Procedure 2.0.1.2 [Operations Procedure Policy]…

(1) Which one of the following describes the requirements for use of EOP flowcharts and 2.4 series procedures?

AND

(2) If an explicit operation is required by EOPs and is addressed in both a 5.1 series procedure and a 5.8 series procedure, which action is required?

A. (1) EOP flowcharts and 2.4 series procedures may be performed concurrently.
   (2) Transition out of the 5.1 series procedure to the 5.8 series procedure.

B. (1) EOP flowcharts and 2.4 series procedures may be performed concurrently.
   (2) Transition out of the 5.8 series procedure to the 5.1 series procedure.

C. (1) EOP flowchart actions MUST be completed first, THEN 2.4 series procedure actions may be taken.
   (2) Transition out of the 5.1 series procedure to the 5.8 series procedure.

D. (1) EOP flowchart actions MUST be completed first, THEN 2.4 series procedure actions may be taken.
   (2) Transition out of the 5.8 series procedure to the 5.1 series procedure.

Answer: A
Explanation:

To support distractor plausibility for part 2, Procedure series numbers were used so the title EOP Support Procedure for series 5.8 procedures would not have to be given. APs (AOPs) are series 2.4 procedures.

EPs (Emergency Procedures) are similar to APs but address more severe conditions than APs and should not be confused with EOPs. Procedure 2.0.1.2 states APs may be used concurrently with EOPs, unless EOP actions conflict with AP actions, in which case EOP actions take precedence. It also states if an explicit operation is directed by EOPs per a 5.8 EOP Support Procedure, then transition shall be made from the Alarm/Abnormal/Emergency/System Operating/Instrument Operating Procedures (including hard cards) to the 5.8 Procedure to perform or continue performing that operation.

Distracters:
Answer B part 1 is correct. Part 2 is plausible because both procedures are intended for emergency conditions. It is wrong because procedure 2.0.1.2 states if an explicit operation is directed by EOPs per a 5.8 EOP Support Procedure, then transition shall be made from the Alarm/Abnormal/Emergency/System Operating/Instrument Operating Procedures (including hard cards) to the 5.8 Procedure to perform or continue performing that operation.

Answer C part 1 is plausible because EOPs/SAMGs are the highest level Operations procedure. An examinee may believe this requires all EOP actions to be prioritized to be performed before actions of other procedures It is wrong because procedure 2.0.1.2 states AP and EOP actions may be performed concurrently as long as they do not conflict, in which case EOPs take precedence. Part 2 is correct.

Answer D part 1 is plausible and wrong for the reason given for distractor C. Part 2 is plausible and wrong for the reason given for distractorB.

Technical References: Procedure 2.0.1.2 [Operations Procedure Policy](Rev 47)

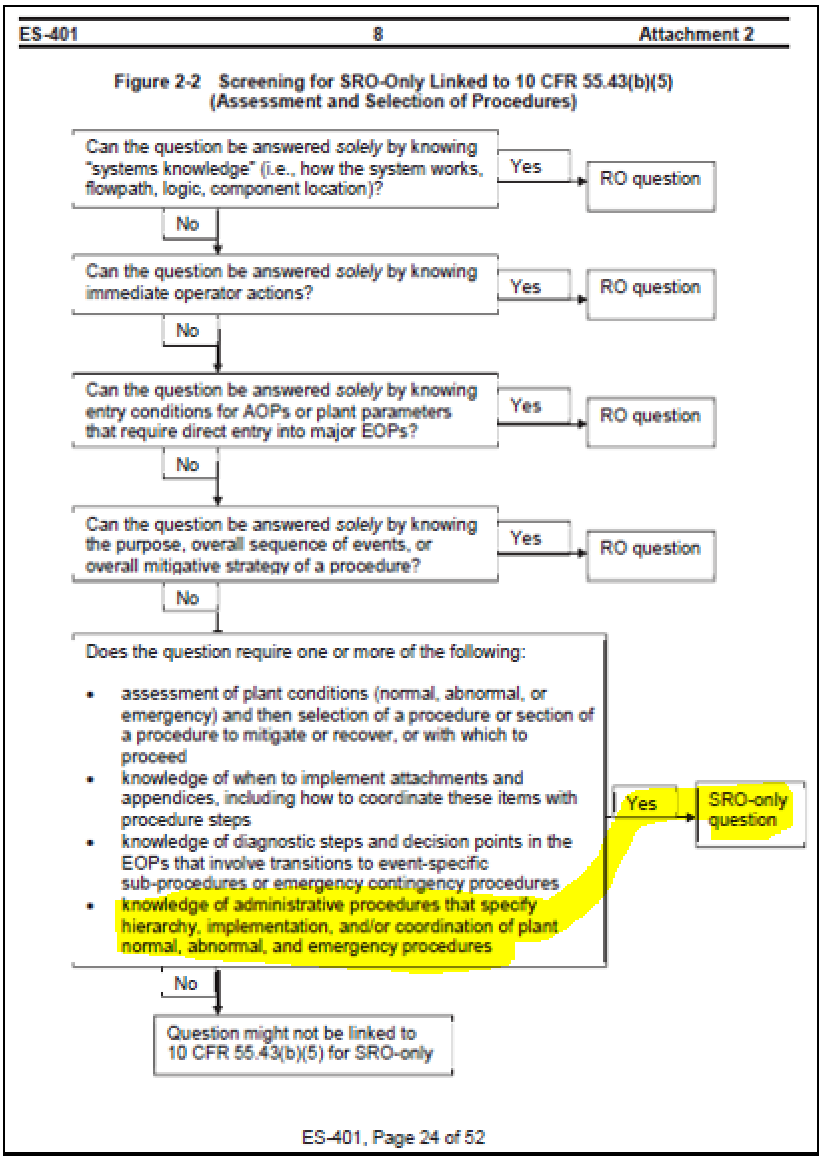
References to be provided to applicants during exam: none

Learning Objective: INT032-01-01 EO-R2, Describe the hierarchy between the Emergency Operating Procedures, Abnormal Procedures, and Emergency Procedures, including which guidance takes precedence

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X

Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	

10CFR Part 55 Content:	55.43(b)(5)
Level of Difficulty:	3
SRO Only Justification:	
This question requires assessment of plant conditions and selection of steps within an emergency (abnormal) procedure attachment with which to proceed. It also requires administrative knowledge of implementation hierarchy between EOPs and APs/EPs.	
PSA Applicability:	
N/A	



6.1.3 APs and EPs use a numeric-alpha numbering scheme. The alpha is a casualty or system descriptor. All APs are 2.4 series. EPs numeric series is defined below.

6.1.3.1 5.1 series typically address whole plant or large area emergencies.

6.1.3.2 5.2 series typically address individual piping system emergencies.

PROCEDURE 2.0.1.2	REVISION 47	PAGE 3 OF 15

6.1.3.3 5.3 series typically address electrical system emergencies.

6.1.3.4 5.4 series typically address fire emergencies.

6.1.3.5 5.5 series typically address security emergencies.

2.2 Operators shall ensure automatic safety initiations and actuations. They shall ensure automatic actions take place in response to valid initiation signals per their safety function design. Upon recognition of a failure of automatic safety feature, Operators shall manually perform those actions necessary to fulfill the safety function.

2.3 If a completed procedure is not retained as a quality record (such as a System Operating Procedure), step discrepancies or non-performance shall be documented/logged as discrepancies. This requirement does not apply to "pen and ink" type discrepancies such as typos and obvious numbering errors.

2.4 The term "Emergency Procedures" as used in this procedure does not include the Emergency Operating Procedures (EOPs)/Severe Accident Guidelines (SAGS) and Emergency Plan Implementing Procedures (EPIPs). Specific EOP usage is addressed in Procedure 5.8.

2.5 Alarm/Abnormal/Emergency/System Operating/Instrument Operating Procedures may be carried out concurrently with an EOP. In the event that conflicting actions are directed by procedures, the EOP actions shall take precedence. EOPs/SAMGs are Operations highest tier procedure. If an explicit operation is directed by EOPs per a 5.8 EOP Support Procedure, then transition shall be made from the Alarm/Abnormal/Emergency/System Operating/Instrument Operating Procedures (including hard cards) to the 5.8 Procedure to perform or continue performing that operation.

2.6 Specific Alarm Procedure usage is addressed in Procedure 2.3.1.

3. SYSTEM AND INSTRUMENT OPERATING PROCEDURES

3.1 SOPs and IOPs contain sections, as applicable, to fill and vent system, startup and secure system, layup system, operate support systems, most typical system operations, and recovering from abnormal or emergency transients.

3.2 SOP and IOP tasks have been structured to perform and complete a task with no consideration for on-going maintenance or abnormal and transient plant conditions. Examples of this are:

3.2.1 Fill and vent sections were created assuming the system was completely drained.

3.2.2 Securing/shutdown sections were created assuming the complete system was in service.

4. HARD CARDS®[a]

4.1 Hard Cards are attachments to applicable Operating Procedures that may be used for the timely operation of equipment needed to mitigate the effects of a transient/accident.

4.2 Hard Cards are created from existing procedure guidance and contain only the steps necessary to accomplish the task in the most expeditious manner.

Examination Outline Cross-Reference	Level	SRO
2.3.11 Ability to control radiation releases.	Tier#	3
	Group#	
	K/A #	2.3.11
	Rating	4.3
	Revision	0
Revision Statement:		

Question 97 From previous 2 NRC Exams 9/2018 ILT NRC Q#98

The plant is operating at low power with:

- Two Circulating Water pumps running
- De-icing in progress

The Floor Drain Sample Tank requires discharging.

1) Whose authorization(s)/approval(s) is/are required in order to accomplish this discharge?

AND

2) What action is required if one of the two operating circulating water pumps trip during the discharge?

A. (1) Shift Manager authorizes and approves the release.
(2) Terminate the discharge

B. (1) Shift Manager authorizes and approves the release.
(2) Reduce the discharge flow rate by 50%.

C. (1) Chemistry department authorizes the release, Shift Manager approves it.
(2) Terminate the discharge

D. (1) Chemistry department authorizes the release, Shift Manager approves it.
(2) Reduce the discharge flow rate by 50%.

Answer: C

Explanation: This question tests knowledge of SRO responsibilities for controlled release of radioactive material. Chemistry Procedure 8.8.11, Attachment 1 requires that chemistry authorizes the release and the duty Shift Manager approves the release. The loss of one CW pump would reduce flow to less than the minimum required 159,000 gpm and the discharge should be terminated. Part of the CW discharge is routed back to the intake structure for de-icing and does not flow to the discharge canal so the credited dilution flow is lowered. When de-icing is in operation, two CW pumps can be credited for 193,200 gpm and one CW pump can be credited with a dilution flow of 118, 800 gpm.		
Distracters: Answer A part 1 is plausible because the SM is the final approval and his authorization is required for rad discharges. It is wrong because Chemistry authorization is first required per procedure 8.8.11 [Liquid Radioactive Waste Discharge Authorization]. Part 2 is is correct. Answer B part 1 is plausible and wrong for the same reasons as stated for distractor A. Part 2 is plausible because loss of one CW pump would result in about 50% reduction in total CW flow. It is wrong because part of total CW flow is diverted to de-icing, so the resultant dilution flow is less than the minimum required for radioactive discharges. Answer D part 1 is correct. Part 2 is plausible and wrong for the same reasons as stated for distractor B.		
Technical References: procedure 8.8.11 [Liquid Radioactive Waste Discharge Authorization](Rev 34)		
References to be provided to applicants during exam: none		
Learning Objective: INT0320115 EO-B1, State who, by title, authorizes releases of radioactive liquid effluents from CNS; EO-B3, State the number of Circulating Water Pumps required to be in service during liquid radioactive discharges.		
Question Source:	Bank # **From previous 2 NRC Exams**	**9/2018 ILT NRC Q#98**
(note changes; attach parent)	Modified Bank #	
	New	
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.43(b)(4)	

Level of Difficulty:	2
SRO Only Justification:	
This tests knowledge of the process for liquid radioactive release approvals and execution..	
PSA Applicability	
N/A	

9/2018 ILT NRC Q#98

Question 98

The plant is operating at low power with:

- Two Circulating Water pumps running
- De-icing in progress

The Floor Drain Sample Tank requires discharging.

1) Whose authorization(s)/approval(s) is/are required in order to accomplish this discharg

AND

2) What action is required if one of the two operating circulating water pumps trip during t
discharge?

A. (1) Shift Manager authorizes and approves the release.
(2) Terminate the discharge

B. (1) Shift Manager authorizes and approves the release.
(2) Reduce the discharge flow rate by 50%.

C. (1) Chemistry department authorizes the release, Shift Manager approves it.
(2) Terminate the discharge

D. (1) Chemistry department authorizes the release, Shift Manager approves it.
(2) Reduce the discharge flow rate by 50%.

Answer: C

C. Facility Licensee Procedures Required To Obtain Authority for Design and Operating Changes in the Facility [10 CFR 55.43(b)(3)]

Some examples of SRO exam items for this topic include the following:

- screening and evaluation processes under 10 CFR 50.59, "Changes, Tests and Experiments"
- administrative processes for temporary modifications
- administrative processes for disabling annunciators
- administrative processes for the installation of temporary instrumentation
- processes for changing the plant or plant procedures

Section IV provides an example of a satisfactory SRO-only question related to this topic.

D. Radiation Hazards That May Arise during Normal and Abnormal Situations, including Maintenance Activities and Various Contamination Conditions [10 CFR 55.43(b)(4)]

Some examples of SRO exam items for this topic include the following:

- process for gaseous/liquid release approvals (i.e., release permits)
- analysis and interpretation of radiation and activity readings as they pertain to the selection of administrative, normal, abnormal, and emergency procedures
- analysis and interpretation of coolant activity, including comparison to emergency plan criteria and/or regulatory limits

SRO-only knowledge should not be claimed for questions that can be answered *solely* based on RO knowledge of radiological safety principles (e.g., radiation work permit requirements, stay time, and DAC hours).

E. Assessment of Facility Conditions and Selection of Appropriate Procedures during Normal, Abnormal, and Emergency Situations [10 CFR 55.43(b)(5)]

This 10 CFR 55.43 topic involves both (1) assessing plant conditions (normal, abnormal, or emergency) and then (2) selecting a procedure or section of a procedure to mitigate or recover, or with which to proceed. One area of SRO-level knowledge (with respect to selecting a procedure) is knowledge of the content of the procedure versus knowledge of the procedure's overall mitigative strategy or purpose.

ATTACHMENT 1 LIQUID RADIOACTIVE WASTE DISCHARGE FORM

ATTACHMENT 1 LIQUID RADIOACTIVE WASTE DISCHARGE FORM

Section 1. REQUEST FOR ANALYSIS OF RADIOACTIVE LIQUID WASTE PRIOR TO DISCHARGE

To: Chemistry From: Shift Manager Tank To Be Discharged: ______

Started Recirculation For Sample: Time: ______ Date: ______

Recirculation Of Tank Complete: Time: ______ Date: ______

Estimated Volume To Be Discharged: ______

Shift Manager: ______ Time: ______ Date: ______

Section 2. THIS SECTION TO BE COMPLETED BY CHEMISTRY

Monitor Source Check

Informed Control Room And Performed Source Check Initials: ______

Monitor Background: ______ Monitor Source Check Value: ______

Sample Point: ______ Sample Time: ______ Date: ______

Signature: ______

Section 3. AUTHORIZATION TO RELEASE RADIOACTIVE LIQUID WASTE

To: Shift Manager From: Chemistry Release Authorization Number: ______

Total µCi/ml: ______

Total Concentration is < 1.0E-02 µCi/ml YES/NO

Signature: ______

31 Day Dose, Percent Of Annual Limit For Each Value Is ≤ 2.0E+00 YES/NO

Signature: ______

You Are Authorized To Release Subject Tank With Following Restrictions:

Maximum Liquid Waste Discharge Rate (gpm): ______

Minimum Dilution Flow To Canal (gpm): 159,000

Discharge Monitor Alarm Setpoint (µCi/ml): ______

NOTE – Terminate Discharge If Above Specifications Cannot Be Maintained. Contents Of This Tank Are Within Chemical Parameters For Discharge.

Chemistry: ______ Time: ______ Date: ______

ATTACHMENT 1 LIQUID RADIOACTIVE WASTE DISCHARGE FORM

Section 4. SHIFT MANAGER APPROVAL TO RELEASE

4.1 Circle Appropriate Discharge Canal Flow Rate:

NUMBER OF OPERATING CW PUMPS	AVERAGE CW DISCHARGE FLOWRATE (gpm)	
	DE-ICING	NO DE-ICING
4	378,600	631,000
3	308,400	514,000
2	193,200	322,000
1	118,800	198,000

4.2 To: Operations Personnel From: Shift Manager

The Subject Tank Contents Are Approved For Release Subject To The Following Restrictions:

1) Maximum Liquid Disch Rate: __________ gpm (Section 3)

2) Minimum Dilution Flow To Canal Of: __________ gpm (Section 3)

3) Alarm Limits Specified (Section 3)

2 x Alarm Limit: ____________________

200 x Alarm Limit: __________________

4) Tank Volume Verified: ____________ (Compare To Section 1)

5) DISCHARGE IN PROGRESS Tags Installed On Running Circ Water Pumps.

Approval To Release:

Shift Manager: ______________________________ Time: ___________ Date: ___________

Examination Outline Cross-Reference	Level	SRO
2.1.4 Knowledge of individual licensed operator responsibilities related to shift staffing, such as medical requirements, "no-solo" operation, maintenance of active license status, 10CFR55, etc.	Tier#	3
	Group#	
	K/A #	G2.1.4
	Rating	3.8
	Revision	0
Revision Statement:		

Question 98 **From previous 2 NRC Exams** **3/2017 ILT NRC Q#94**

A CRS, who is also qualified as Shift Manager and as STE, began reactivation as SRO on May 1st, after an extended absence.

The SRO signed into eSOMS and completed Procedure 2.0.7 [Licensed Operator Active/Reactivation/Medical Status Maintenance Program], Att. 4 [SRO Reactivation] per the following:

May 1	May 2	May 3	May 4	May 5	May 6	May 7
12 hours under instruction (CRS initialed as coach)	12 hours under instruction (CRS initialed as coach)	12 hours under instruction (Shift Mgr initialed as coach)			12 hours as on-shift STE	12 hours as on-shift STE
May 8	**May 9**	**May 10**	**May 11**	**May 12**	**May 13**	**May 14**
		12 hours under instruction (Shift Mgr initialed as coach)			12 hours under instruction (CRS initialed as coach)	12 hours under instruction (CRS initialed as coach)

When did the SRO complete the **minimum** proficiency time for reactivation IAW Procedure 2.0.7 [Licensed Operator Active/Reactivation/Medical Status Maintenance Program]?

A. May 6

B. May 7

C. May 10

D. May 14

Answer: C
Explanation: IAW Procedure 2.0.7 [Licensed Operator Active/Reactivation/Medical Status Maintenance Program], step 2.8.5 specifies a minimum of four 12-hours shifts to meet the NRC required 40 hours for reactivation of an SRO license. Att. 4, SRO Reactivation, specifies 40 hours of under instruction proficiency time is required for reactivation, and SRO Licensees proficiency time is performing on-shift license authorized (CRS and/or SM) position tasks under active SRO (Coach) direction, so under instruction of either CRS or SM counts toward the required proficiency time. Time acting as STE, not under instruction for proficiency, does not count. Therefore, the four 12-hour shift (40 hour NRC) requirement would be completed after the fourth 12 hour day under instruction of either the CRS or SM, which is on May 10.
Distracters: Answer A is plausible because it reflects the fourth day of work after beginning reactivation, so 40 work hours would have elapsed. It is wrong because only 36 hours of under instruction time for proficiency would have been reached, which is less than the required 40 hours. Answer B is plausible because it reflects the fifth day of work and 60 total hours, the normal period required in a quarter for maintaining proficiency. The unprepared applicant may confuse the proficient requirement of 40 hours with a familiar limit of 60 hours and select this answer. It is wrong because only 36 hours of under instruction time for proficiency would have been reached, which is less than the required 40 hours. Answer D is plausible because it reflects the day 40 hours of U/I time under the CRS is reached. The unprepared applicant may believe, since he/she is primarily a CRS, only U/I under the CRS counts toward his/her proficiency. It is wrong because procedure 2.0.7 Att 4 states U/I time to regain proficiency may be under CRS or SM; therefore, the minimum requirement is met earlier than this answer reflects.
Technical References: Procedure 2.0.7 [Licensed Operator Active/Reactivation/Medical Status Maintenance Program](Rev 11)
References to be provided to applicants during exam: none
Learning Objective: INT032-01-01 EO-S1e, Discuss the following as described in 2.0.7 Licensed Operator Active/Reactivation/Medical Status Maintenance Program: Reactivation

Question Source:	Bank # **From previous 2 NRC Exams**	**3/2017 ILT NRC Q#94**
(note changes; attach parent)	Modified Bank #	
	New	
Question Cognitive Level:	Memory/Fundamental	
	Comprehensive/Analysis	X
10CFR Part 55 Content:	55.43(b)(1)	
Level of Difficulty:	3	
SRO Only Justification:		
This question tests knowledge of requirements for maintenance of active license status related to shift staffing requirements of the Operating License that is specific to SROs.		
PSA applicability:		
N/A		

3/2017 ILT NRC Q#94

Question 94

A CRS, who is also qualified as Shift Manager and as STE, began reactivation as SRO on May 1st, after an extended absence.

The SRO signed into eSOMS and completed Procedure 2.0.7 [Licensed Operator Active/Reactivation/Medical Status Maintenance Program], Att. 4 [SRO Reactivation] per the following:

May 1	May 2	May 3	May 4	May 5	May 6	May 7
12 hours under instruction (CRS initialed as coach)	12 hours under instruction (CRS initialed as coach)	12 hours under instruction (Shift Mgr initialed as coach)			12 hours as on-shift STE	12 hours as on-shift STE
May 8	**May 9**	**May 10**	**May 11**	**May 12**	**May 13**	**May 14**
		12 hours under instruction (Shift Mgr initialed as coach)			12 hours under instruction (CRS initialed as coach)	12 hours under instruction (CRS initialed as coach)

When did the SRO complete the **minimum** proficiency time for reactivation IAW Procedure 2.0.7 [Licensed Operator Active/Reactivation/Medical Status Maintenance Program]?

A. May 6

B. May 7

C. May 10

D. May 14

Answer: C. May 10

II. Examples of additional knowledge and abilities as they pertain to an SRO license and the 10 CFR 55.43(b) topics [ES-401N, Section D.1.c]**:**

A. Conditions and limitations in the facility license. [10 CFR 55.43(b)(1)]

Examples of SRO exam items for this topic include:

- Reporting requirements when the maximum licensed thermal power output is exceeded.
- Administration of fire protection program requirements such as compensatory actions associated with inoperable sprinkler systems, fire doors, etc.
- The required actions for not meeting administrative controls listed in Technical Specification (TS) Section 5 or 6, depending on the facility (e.g., shift staffing requirements).
- National Pollutant Discharge Elimination System (NPDES) requirements, if applicable.
- Processes for TS and FSAR changes.

2.4 Reactivation - Fulfilling deficient areas to achieve active status again. Ideally accomplished within calendar quarter.

2.5 Requal Training - NRC approved Licensed Operation Requal Training Program requirements.

2.6 Plant Tour - Tour all safely accessible areas of power block buildings/areas to ensure Licensee is current with plant and equipment status, location of in-plant controlled procedures, changes in posted Radiological Controlled Areas, etc. Tour must be under active SRO direction. Tour shall be completed during the 40 hour reactivation.

2.7 Coach - Active license RO or SRO coaches and monitors RO performing RO tasks during reactivation. Active license SRO coaches and monitors SRO performing CRS or SM tasks during reactivation.

2.8 Proficiency Time - Performing license authorized (RO, BOP, CRS, or SM) tasks to which Licensee is/will be assigned.

2.8.1 Track time on attachments and sign in Control Room Logs is recommended.

2.8.2 Extra fifth license position is not counted towards proficiency time.

2.8.3 Licensee should have no other concurrent duties.

NOTE – SRO is not required to stand panel watches to remain active to assume panel watch. Time spent on panel watch cannot be counted toward maintaining SRO active.

2.8.4 Maintaining Active Status - Licensees perform RO or SRO tasks for minimum of seven 8-hour or five 12-hour shifts per calendar quarter.

2.8.5 Reactivation - Licensee performs RO or SRO tasks for minimum of four 12-hour shifts (NRC requires 40 hours) under Coach direction.

2.8.6 Initial Activation - Licensee who has not completed a minimum of five 12-hour shifts under instruction in the quarter of or quarter proceeding receipt of their license shall perform a minimum of four 12-hour shifts under instruction prior to assuming licensed operator duties.

2.8.7 Under instruction and reactivation time satisfies active requirements; additional proficiency time is not required during calendar quarter.

3. RESPONSIBILITIES

3.1 Licensee shall:

3.1.1 Maintain active status, accurately completes and timely submits Attachment 1 for RO or Attachment 3 for SRO.

3.1.2 Accurately completes Attachment 2 for RO or Attachment 4 for SRO.

guidance outlined in Section 6.

7. REACTIVATION®[2]

7.1 Licensee shall:

7.1.1 Ensure compliance with active definition above completed prior to or during reactivation.

7.1.2 Review training/medical examination status. Complete any required items that are not up-to-date. Contact Operations Training, as needed, to complete training requirements.

7.1.3 Document proficiency time on Attachment 2 for RO or Attachment 4 for SRO.

7.1.3.1 Sign into eSOMS as an Under Instruction (U/I) to track proficiency time.

7.1.4 Document required procedure reading performance on attachment.

7.1.5 Document plant tour completion.

7.1.5.1 Plant tour shall be completed with and accompanied by an active SRO (Coach) and shall be performed during the 40 hour reactivation.

7.2 Active SRO Coach shall:

7.2.1 Initial proficiency time space.

7.2.2 Print name and date for each building toured with Licensee.

7.2.3 List tour observations and discussions on attachment.

ATTACHMENT 4 SRO REACTIVATION

ATTACHMENT 4 SRO REACTIVATION

Lesson Number: CNS001-01-88 BET 1396	Lesson Title: SRO Active Status Maintenance						Rev: 00	*Completion Date:	
Name (Print) / (X) Signature	Identification Number	SAT	UNSAT	INC	REG	Ch. Exam	Remarks	Records Input	Records Verify
		✓							

SHIFT TASKS

SRO Licensees proficiency time is performing on-shift license authorized (CRS and/or SM) position tasks under active SRO (Coach) direction. During this time, procedures pertaining to Operations Policy and shift turnover shall be reviewed. Shift tasks include any plant equipment operation, Clearance Order activity, Surveillance Procedures, shift turnovers, current ODMIs, and other significant Operational issues.

Document time below, and print-off and attach shift staffing report using eSOMS.

	BEGINNING OF SHIFT DATE	SHIFT	POSITION WORKED	COACH INITIALS
1)				
2)				
3)				
4)				

Additional time spent on-shift may be documented on a separate sheet and attached.

PROCEDURE REVIEW

2.0.1 Plant Operations Policy Initials: ________

2.0.2 Operations Logs and Reports Initials: ________

2.0.3 Conduct of Operations Initials: ________

2.0.4 Relief Personnel and Shift Turnover Initials: ________

2.0.9 Control of Operator Aids Initials: ________

2.0.12 Operator Challenges Initials: ________

ATTACHMENT 4 SRO REACTIVATION

Licensee Name: ______________________________

PLANT TOUR

Plant tour shall be completed with and accompanied by an active SRO (Coach) during the 40 hour reactivation. Tour may be performed as multiple tours to cover all buildings and shall include **ALL safely accessible** areas of following buildings/areas:

	COACH NAME/DATE (Please Print)
REACTOR BUILDING	____________ / ______
TURBINE BUILDING	____________ / ______
RADWASTE BUILDING	____________ / ______
AUGMENTED RADWASTE	____________ / ______
CONTROL BUILDING	____________ / ______
DIESEL GENERATOR BUILDING	____________ / ______
INTAKE STRUCTURE	____________ / ______
345 AND 161 KV SWITCHYARDS	____________ / ______

ITEMS OBSERVED/DISCUSSED DURING TOUR

____
____
____
____
____
____
____
____
____

SPECIAL PRESCRIPTION RESPIRATOR GLASSES VERIFICATION

Corrective respirator glasses are part of my NRC license condition: [ ] YES; [ ] NO

If YES, then I have verified my corrective respirator glasses are located in Control Room repository.

Initials: ________

Examination Outline Cross-Reference	Level	SRO
2.4.40 Knowledge of SRO responsibilities in emergency plan implementation.	Tier#	3
	Group#	
	K/A #	G2.4.40
	Rating	4.5
	Revision	0
Revision Statement:		

Question 99

A General Emergency Protective Action Recommendation (PAR) is being issued for the first time during a SLOWLY progressing event.

Wind direction is from 180° directly to and along the centerline of Sector A.

Assuming no impediments for evacuation exist,

(1) What is the MINIMUM **radius** for which **ALL** sectors must be evacuated?

AND

(2) What is the MINIMUM **number of downwind sectors** that must be evacuated beyond the ALL sectors radius?

A. (1) 2 miles
(2) 3

B. (1) 2 miles
(2) 4

C. (1) 5 miles
(2) 3

D. (1) 5 miles
(2) 4

Answer: A
Explanation: The Shift Manager is an SRO and assumes the role of On-shift Emergency Director when an EAL is met. The Shift Manager is responsible for approving PARs IAW Procedure 5.7.20. The standard PAR for a GE requires evacuating all sectors out to

two miles and downwind sectors out to five miles. Affected downwind sectors are determined based on wind direction using Procedure 5.7.20 Att. 5. There are 16 equal sectors covering the entire 360 degrees around the site. Each sector covers 22.5 degrees. A minimum of three sectors are affected for PARs, the sector covering the direction the wind is blowing toward and one sector on either edge/side of it. If the wind direction is within three degrees of the boundary of two sectors, then those two sectors plus their other adjacent sectors, which makes a total of four sectors. For the case given, the wind direction is along the centerline of sector A, which is ~eleven degrees from the closest edge of sector A: therefore, only three sectors are required to be evacuated out to five miles. (sectors R,A,B)
Distracters: Answer B part 1 is correct. Part 2 is plausible because if the wind direction is within three degrees of the boundary of two sectors, then those two sectors plus their other adjacent sectors, which makes a total of four sectors. This answer is wrong because the wind direction is along the centerline of sector J, which is ~ eleven degrees from the closest edge of sector J: therefore, only three sectors are required to be evacuated out to five miles. Answer C part 1 is plausible because the standard PAR for a GE requires evacuating downwind sectors out to 5 miles. It is wrong because all sectors are only required to be evacuated out to a radius of 2 miles. Part 2 is correct. Answer D part 1 is plausible and wrong for the reason given for distractor C. Part 2 is plausible and wrong for the reason given for distractor B.
Technical References: procedure 5.7.20 [Protective Action Recommendations](Rev 31)
References to be provided to applicants during exam: none
Learning Objective: ERO001-01-15 EO-3b, State the PAR to be given to off-site authorities at a General Emergency for the following: A Non-Rapidly Progressing Severe Accident (RPSA)

Question Source:	Bank #	
(note changes; attach parent)	Modified Bank #	
	New	X
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.43(b)(5)	
Level of Difficulty:	3	

SRO Only Justification:	
Requires knowledge of specific information in an Emergency Plan Implementing Procedure attachment required to approve Protective Action Recommendations.	
PSA Applicability:	
N/A	

E. Assessment of Facility Conditions and Selection of Appropriate Procedures during Normal, Abnormal, and Emergency Situations [10 CFR 55.43(b)(5)]

This 10 CFR 55.43 topic involves both (1) assessing plant conditions (normal, abnormal, or emergency) and then (2) selecting a procedure or section of a procedure to mitigate or recover, or with which to proceed. One area of SRO-level knowledge (with respect to selecting a procedure) is knowledge of the content of the procedure versus knowledge of the procedure's overall mitigative strategy or purpose.

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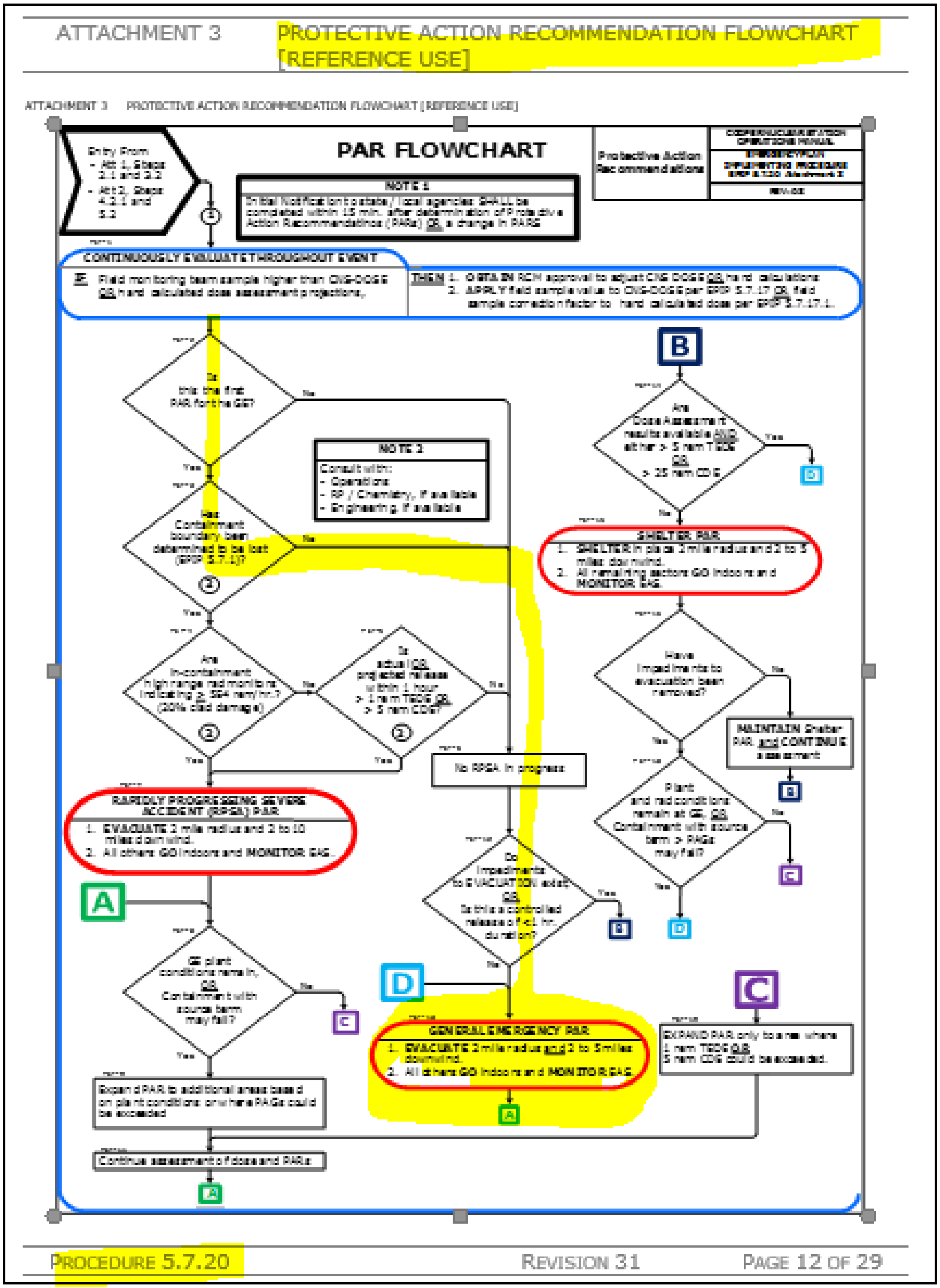
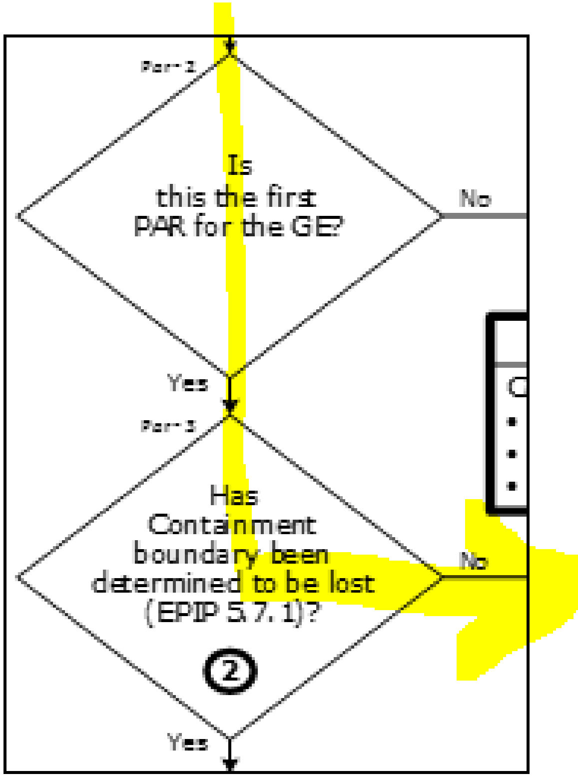
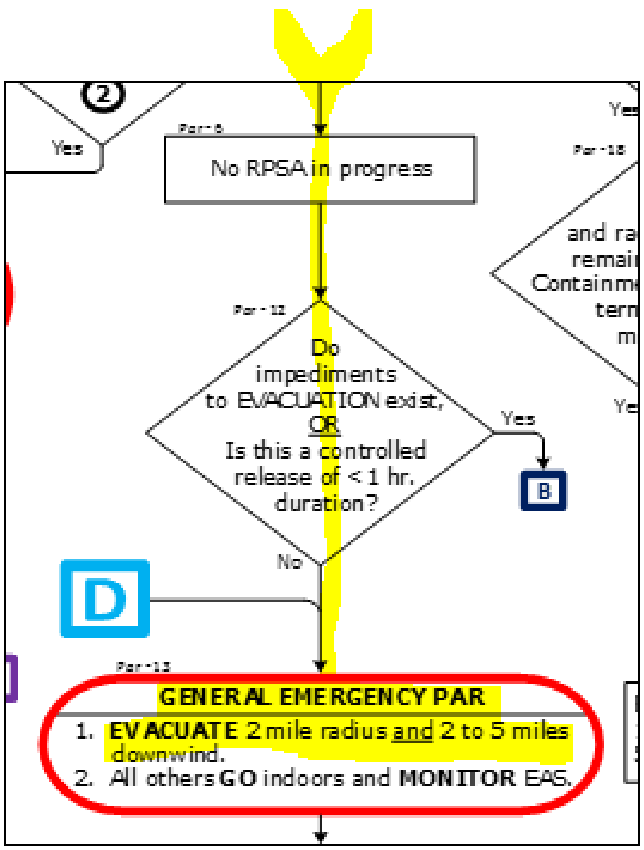

ATTACHMENT 3 PROTECTIVE ACTION RECOMMENDATION FLOWCHART [REFERENCE USE]
PAR FLOWCHART
Protective Action Recommendations
NOTE 1
NOTE 2
CONTINUOUSLY EVALUATE THROUGHOUT EVENT
SHELTER PAR
MAINTAIN Shelter PAR and CONTINUE assessment
No RPSA in progress
RAPIDLY PROGRESSING SEVERE ACCIDENT (RPSA) PAR
GENERAL EMERGENCY PAR
Continue assessment of dose and PARs
PROCEDURE 5.7.20
REVISION 31
PAGE 12 OF 29


Par - 2
Is this the first PAR for the GE?
No
Yes
Par - 3
Has Containment boundary been determined to be lost (EPIP 5.7.1)?
No
2
Yes


2
Yes
Par - 8
No RPSA in progress
Par - 12
Do impediments to EVACUATION exist, OR Is this a controlled release of < 1 hr. duration?
Yes
B
No
D
Par - 13
GENERAL EMERGENCY PAR
1. EVACUATE 2 mile radius and 2 to 5 miles downwind.
2. All others GO indoors and MONITOR EAS.

ATTACHMENT 4 FLOWCHART DECISION BASIS [INFORMATION USE]

NOTE – A Rapidly Progressing Severe Accident (RPSA) is a General Emergency with loss of containment integrity (emergency action levels indicate containment barrier loss) and loss of ability to cool core. This path is used for scenarios in which containment integrity can be determined as bypassed or immediately lost during General Emergency with core damage.

4. **DETERMINE** if RPSA is occurring.

4.1 IF these criteria cannot be immediately confirmed, THEN **ASSUME** RPSA is not taking place.

4.2 Step Par-2: *Is this the first PAR for the GE?* This question is establishing whether there is an existing PAR in effect and being executed.

4.2.1 If PARs already in effect, then RPSA extended PARs are not warranted.

4.3 Step Par-3: *Has Containment Boundary been determined to be lost per EPIP 5.7.1, Attachment 3, Table F-1?* Potential losses do not meet this criterion. The intention is to anticipate significant radiological release and off-site dose due to loss of containment meeting assumptions that warrant extended RPSA default PARs.

4.3.1 If containment is intact, then applying RPSA extended PARs are not warranted.

4.4 Step Par-4: *Are in-containment high range radiation monitors indicating greater than or equal to 5E4 rem/hr?* This corresponds to equivalent of about 20% clad damage. This step provides a quick assessment as to state of reactor core and fuel integrity.

4.4.1 If in-containment monitors indicate this level of fuel damage, then applying RPSA extended PARs is warranted in anticipation of eventual extremely high radiological release rates and resulting off-site dose.

4.4.2 If in-containment monitors do not indicate this level of fuel damage, then applying RPSA extended PARs is not warranted unless decision of Step Par-5 is YES.

ATTACHMENT 5 AFFECTED SECTOR DETERMINATION [INFORMATION USE]

NOTE 1 – Wind direction is given as "wind from" (easterly wind or wind direction 90° means wind blowing from east to west).

NOTE 2 – Effective Sector Determination table below adds additional sector if wind direction is within 3° of sector edge.

TABLE 1

WIND FROM (°)	SECTORS AFFECTED	WIND FROM (°)	SECTORS AFFECTED	WIND FROM (°)	SECTORS AFFECTED
351 to 9	H, J, K	126 to 144	P, Q, R	261 to 279	D, E, F
10 to 13	H, J, K, L	145 to 148	P, Q, R, A	280 to 283	D, E, F, G
14 to 31	J, K, L	149 to 166	Q, R, A	284 to 301	E, F, G
32 to 35	J, K, L, M	167 to 170	Q, R, A, B	302 to 305	E, F, G, H
36 to 54	K, L, M	171 to 189	R, A, B	306 to 324	F, G, H
55 to 58	K, L, M, N	190 to 193	R, A, B, C	325 to 328	F, G, H, J
59 to 76	L, M, N	194 to 211	A, B, C	329 to 346	G, H ,J
77 to 80	L, M, N, P	212 to 215	A, B, C, D	347 to 350	G, H, J, K
81 to 99	M, N, P	216 to 234	B, C, D		
100 to 103	M, N, P, Q	235 to 238	B, C, D, E	There is no O Sector	
104 to 121	N, P, Q	239 to 256	C, D, E		
122 to 125	N, P, Q, R	257 to 260	C, D, E, F	There is no I Sector	

1.4 IF wind shift observed following initial PAR issuance, THEN downwind sectors should be **RE-EVALUATED** for inclusion of new sectors (do not delete sectors) as follows:

NOTE 1 – During extreme wind shift due to severe weather, PARs should not be extended to sectors wind is rapidly shifting through unless shown by dose assessment projection EPA PAGs would be exceeded in those sectors for short duration of release.

NOTE 2 – Plant condition based PARs should be based on wind direction after extreme wind shift has subsided.

1.4.1 IF GE declared based on existing plant conditions, THEN PARs should be **EXPANDED** to include new sectors.

Examination Outline Cross-Reference	**Level**	SRO
2.1.35 Knowledge of fuel handling responsibilities of SROs	**Tier#**	3
	Group#	
	K/A #	G2.1.35
	Rating	3.9
	Revision	0
Revision Statement:		

Question 100

Which activity REQUIRES Refuel Floor Supervisor permission during refueling operations in Mode 5?

A. Using greater than 50 gallons of demineralized water on the refuel floor

B. Re-commencing fuel handling operations

C. Allowing access to Reactor Bldg 1001'

D. Allowing under vessel access

Answer: B

Explanation:
Refuel Floor Supervisor permission is required to re-commence fuel handling operations IAW Procedure 2.2.31 Attachment 2 (Reset Checklist) which shall be used each time the normal fuel handling process is stopped/interrupted. This includes, but is not limited to, Shift Turnover, Fuel Mover/Spotter mid-shift role change, or following a distraction which interrupts the normal fuel handling process flow. Putting the applicable procedure in the stem would eliminate under vessel access plausibility due to title being "Fuel Handling - Refueling Platform".

Distracters:
Answer A is plausible due to the Refuel floor SRO is required to brief available refueling floor personnel on limiting demineralized water usage and requirement to notify Control Room if using > 50 gallons demineralized water each shift. The candidate who confuses briefing vs. giving permission would choose this answer. This answer is incorrect because Refuel Floor Supervisor permission is not required to use greater than 50 gallons of demineralized water on the refuel floor.

Answer C is plausible due to the Refuel floor SRO permission is required to access the fuel handling area - the fuel handling area is located Rx Bldg 1001'. The candidate who confuses refuel floor with fuel handling area would choose this answer. This answer is incorrect because Refuel Floor Supervisor permission is not required to allow access to the refuel floor. Answer D is plausible because under vessel area gets posted to prohibit access without Shift Manager's permission. The candidate who confuses access permission authority would select this choice. This answer is incorrect because Refuel Floor Supervisor permission is not required to allow access to the under vessel area.
Technical References: Procedure 2.1.20.3 [RPV Refueling Preparation (Wet Lift of Dryer and Separator)](Rev 67), Procedure 10.25 [Refueling - Core Unload, Reload, and Shuffle](Rev 65), Procedure 2.2.31 [Fuel Handling - Refueling Platform](Rev 57)
References to be provided to applicants during exam:
Learning Objective: INT0231002001160A Identify the administrative duties and responsibilities of the each of the following: Refueling Floor Supervisor

Question Source:	Bank #	4/2015 ILT NRC Q#95
(note changes; attach parent)	Modified Bank #	
	New	
Question Cognitive Level:	Memory/Fundamental	X
	Comprehensive/Analysis	
10CFR Part 55 Content:	55.43(b)(7)	
Level of Difficulty:	3	
SRO Only Justification:		
This question requires knowledge of Refuel floor SRO responsibilities.		
PSA Applicability:		
N/A		

From 4/2015 ILT NRC exam

Question: 95

Which activity REQUIRES Refuel Floor Supervisor permission during refueling operations in Mode 5?

A. Allowing under vessel access.

B. Allowing access to the refuel floor.

C. Re-commencing fuel handling operations.

D. Using greater than 50 gallons of demineralized water on the refuel floor.

Answer:
C. Re-commencing fuel handling operations.

F. Procedures and Limitations Involved in Initial Core Loading, Alterations in Core Configuration, Control Rod Programming, and Determination of Various Internal and External Effects on Core Reactivity [10 CFR 55.43(b)(6)]

Some examples of SRO exam items for this topic include the following:

- evaluation of core conditions and emergency classifications based on core conditions
- administrative requirements associated with low-power physics testing processes
- administrative requirements associated with refueling activities, such as approvals required to amend core loading sheets or administrative controls of potential dilution paths and/or activities
- administrative controls associated with the installation of neutron sources
- knowledge of TS bases for reactivity controls

G. Fuel-Handling Facilities and Procedures [10 CFR 55.43(b)(7)]

Some examples of SRO exam items for this topic include the following:

- refuel floor SRO responsibilities
- assessment of fuel-handling equipment SR acceptance criteria
- prerequisites for vessel disassembly and reassembly
- decay heat assessment
- assessment of SRs for the refueling mode
- reporting requirements
- emergency classifications

This list does not include items that the RO may be responsible for at some sites, such as fuel-handling equipment and refueling-related control room instrumentation operability requirements, and AOP immediate actions. For example, an RO is required to stop the refueling process when communication is lost between the control room and the refueling floor; therefore, this task is both an RO and SRO responsibility, not an SRO-only responsibility.

III. Justification for Plant-Specific Exemptions

The 25 SRO-only questions *shall* evaluate the additional K/As required for the higher license level in accordance with 10 CFR 55.43(b). [Section D.2.d of this examination standard]

The fact that a facility licensee trains its ROs to master certain 10 CFR 55.43 K/As and skills does NOT mean that they can no longer be used as a basis for SRO-only questions. [Operator Licensing Program Feedback Item 401.36]

ATTACHMENT 2 RESET CHECKLIST

ATTACHMENT 2 RESET CHECKLIST

Fuel handling Reset Checklist shall be used each time normal fuel handling process stopped/interrupted. This includes, but not limited to, Shift Turnover, Fuel Mover/Spotter mid-shift role change, or following a distraction which interrupts normal fuel handling process flow.

Spotter shall perform fuel handling Reset Checklist by reading each step to Fuel Mover and Mover responding with appropriate response. Spotter shall verify response is as expected.

1. Current fuel move sheet page number.
2. Current step number.
3. Current Z-elevation of grapple/tool.
4. Location of bridge north/south control.
5. Location of trolley east/west control.
6. Location grapple raise/lower control.
7. Core/pool location of next move.
8. Current configuration of component/grapple (IS/IS not clear).
9. Sequence of specific control manipulations required to recommence fuel handling.
10. Permission from Refuel Floor SRO to recommence fuel handling operations.

4.7.6 Lock Mode switch to REFUEL and remove key.

4.7.7 A hardcopy of the approved SNM Transfer Form (Procedure 10.21, Attachment 1) is on Refueling Floor and in the Control Room.

4.7.8 Perform Procedures 6.REFUEL.302, 6.LOG.602, and 6.REFUEL.305 refueling requirement checks (LCO 3.9.1).

4.7.9 Section 4.7 steps have been completed.

SM Signature/Date: ______________________

4.8 Drywell accountability has been completed.

Outage Drywell Coordinator Signature/Date: ______________________

4.9 Radiation Protection shall perform or verify following:

4.9.1 Drywell ARMs are installed and operational.

4.9.2 Access to drywell third level is restricted by radiological posting and radiation area barrier with a very high radiation area lock.Ⓟ[4]

4.9.3 A Special Work Permit has been prepared to cover refueling.

4.9.4 Drywell has been posted to prohibit access without Radiation Protection permission.

RP Signature/Date: ______________________

NOTE – Under vessel access is allowed if requirements of Step 6.1 are met.

4.10 Under vessel area has been posted to prohibit access without Shift Manager's permission. This is to limit spurious reactor scrams.Ⓢ[1]

SM Signature/Date: ______________________

4.11 Reactor Engineer will verify following:

4.11.1 SDM requirements per SR 3.1.1.1 are met during all planned refueling operations.

4.11.2 SNM Transfer Form meets requirements of Procedure 10.6.

Reactor Engineer Signature/Date: ______________________

4.12 CAUTION tag placed on rod movement control switch (may be cleared if fuel moves are suspended) (LCO 3.9.3 or 3.10.6).

SM Signature/Date: ______________________

1. PURPOSE

   1.1 Operation of refueling platform.

2. PRECAUTIONS AND LIMITATIONS

   2.1 Personnel over-exposure may occur during use of RAISE OVERRIDE function of either monorail or frame mounted hoists due to unmonitored removal of radioactive material from spent fuel storage pool (SFSP) or reactor cavity.

   2.2 Personnel over-exposure may occur due to failure of short mast and long mast main hoist raise cutout limits.

   2.3 Refueling Platform Operators must be qualified to TQD-232, Refuel Bridge Operator.

   2.4 Prevention of material from falling into RPV, reactor cavity, or spent fuel storage pool maintained by requirements of Procedures EN-MA-118 and 7.4.32.

   2.5 Operation of SYSTEM STOP button (Operators console) will stop undesired movement of refuel bridge.

   2.6 Release of radioactive materials may occur from careless handling practices due to irradiated fuel rods may be brittle and contain fission gases under pressure.

   2.7 Force applied to refuel platform mast cable may produce electrical cable faults.Ⓟ[4]

   2.8 While working in proximity of a LPRM, SRM, or IRM assemblies, applying a downward force to either boss on plunger section may dislodge assembly from top grid.

   2.9 Access to fuel handling area on refueling floor and overhead bridge crane when fuel handling in-progress shall be permitted to personnel with Refuel Floor SRO authorization.

   2.10 No more than one fuel bundle should be suspended above fuel storage array to limit fuel damage if bundle was dropped.

   2.11 Fuel bundle being moved shall be less than 24" above fuel storage array.

NOTE 1 – Steps 4.23 and 4.24 may be performed concurrently with remainder of Section 4.

NOTE 2 – Step 4.24 may be performed before Step 4.23.

4.23 **ENSURE** night shift Refuel Floor SRO briefs available Refuel Floor personnel to include following:®[2]

- **LIMIT** demineralized water usage.
- **NOTIFY** Control Room if using greater than 50 gallons demineralized water.

Initials/Time/Date: ______/______/______

4.24 **ENSURE** day shift Refuel Floor SRO briefs available Refuel Floor personnel to include following:®[2]

- **LIMIT** demineralized water usage.
- **NOTIFY** Control Room if using greater than 50 gallons demineralized water.

Initials/Time/Date: ______/______/______

NOTE – Steps 4.25 through 4.28 may be performed concurrently.

4.25 WHEN average reactor coolant temperature less than 212°F, THEN **INFORM** Maintenance commence drywell head removal per Procedure 7.4DISASSEMBLY.

Initials/Time/Date: ______/______/______

4.26 **LOWER** and **MAINTAIN** average reactor coolant temperature 115°F to 190°F until RPV level raised 3' to 4' above RPV flange.

Initials/Time/Date: ______/______/______

4.27 **CLOSE** RWCU-395, INLET SUBCOOLING ISOLATION (RWCU HX Room west between heat exchangers).

Initials/Time/Date: ______/______/______