Grading summary spreadsheet

Summary of finalized corrections

3 Question 19

4 Question 23

5 Question 25

6 Question 37

7 Question 47

8 Question 71

9 Question SRO 3

10 Question SRO 7

11 Question SRO 12

12 Question SRO 22

13 Question SRO 23

14 Question SRO 25

15

Summary of finalized corrections:

- Question 19: accept two answers, “c” and “d”
- Question 23: accept two answers, “b” and “c”
- Question 25: accept two answers, “b” and “c”
- Question 37: accept two answers, “c” and “d”
- Question 47: accept two answers, “b” and “d”
- Question 71: accept two answers, “a” and “d”
- Question SRO 3: accept two answers, “a” and “b”
- Question SRO 7: accept two answers, “a” and “b”
- Question SRO 12: no correct answers, delete the question
- Question SRO 22: correct answer is “b”
- Question SRO 23: all 4 answers are correct, delete the question
- Question SRO 25: accept two answers, “c” and “d”

Question 19

This question has some mis-leading information within the stem, which caused some of the candidates to arrive at a different answer than was expected. This was due to wording within the stem that was in quotation marks. One of the bullets states:

- You are operating “all available DW cooling”

Since the candidates had a copy of the Primary Containment Control EOP, and given the wording contained within the quotation marks, it is NOT unreasonable for them to go to the step in the Drywell Temperature leg containing the wording “Operate all available drywell cooling IAW S.P. 27”. Support Procedure 27 directs the operator to bypass the RBCCW isolation signals and start all available drywell recirc fans.

The stem wording “all available DW cooling” is operating implies that Support Procedure 27 has already been performed. In this case, RBCCW would have been bypassed and the correct answer to the question would be “d”, rated capacity of DW recirc fans is inadequate. This would be true if Primary Containment Control had been entered and Support Procedure 27 had already been performed, and a subsequent re-entry condition exists causing a re-entry to Primary Containment Control.

If this is the first time the question of being able to maintain bulk drywell temperature below 150 deg. F is asked, the stem of the question should have referenced the previous step in Drywell Temperature Control (“Maintain bulk drywell temperature below 150 deg. F using available drywell coolers.”) If available drywell coolers is in quotation marks, there is no way the candidate can become confused with the wording in the quotation marks, given its location in the flowchart.

The wording “available drywell coolers” is different from “all available drywell cooling”. Available drywell coolers implies the drywell cooling system is being operated within normal operating procedures, which specifies only 4 of 5 drywell recirc fans running, with RBCCW supplied to the coolers. The wording “all available drywell cooling” directs RBCCW isolations to be bypassed and all 5 recirc fans to be operated.

Based upon interpretation of the “all available drywell cooling”, coupled with the other plant conditions, the candidate could reach the conclusion that RBCCW has indeed isolated, which would make “c” the correct answer.

Therefore, since there is no time line given for the LOCA event, and given the “all available DW cooling” in quotation marks, answers “c” and “d” are correct.

References: EMG-3200.02, Primary Containment Control
EOP User’s Guide, pp. 2-14 through 2-16

QUESTION #19

Given the following conditions:

- A Loss of Offsite Power has occurred
- Reactor is at rated temperature and pressure
- The drywell pressure entry condition for EMG-3200-02, "Primary Containment Control" has been satisfied.
- Reactor water level is 0" TAFand decreasing.
- You are operating "all available DW cooling" .
- The CRS asks: "Can bulk drywell temperature be maintained below 150 degrees F?"
- Your response is "NO".

What is the basis for this response?

A. A LOCA signal has caused Chilled Water to isolate.

B. A High Drywell Pressure signal has caused Drywell Recirc fans to trip.

C. A LOCA signal has caused RBCCW isolation valves to isolate.

D. The rated capacity of 5 Drywell Recirc fans is inadequate.

ANSWER: C

EXPLANATION:
RBCCW isolation occurs with Lo-Lo water level and High Drywell Pressure. Without RBCCW there is no heat sink for drywell cooling and temperature cannot be reduced. The RBCCW isolation must be cleared or bypassed (Support Procedure 27) this is done if/when the answer is "NO".

TECHNICAL REFERENCE(S): Primary Containment Lesson Plan pg 13; EOP-2 (Attach if not previously provided)

Proposed references to be provided to applicants during examination: EOPs

Learning Objective: (04) 07346 (As available)

Examination Outline Cross-reference:

Level	RO	SRO
Tier #	1	___
Group #	1	___
K/A #	295028/EA1.02	
Importance Rating	3.9	___

K/A Topic Description:
Ability to operate and/or monitor the drywell ventilation system as it applies to high drywell temperature

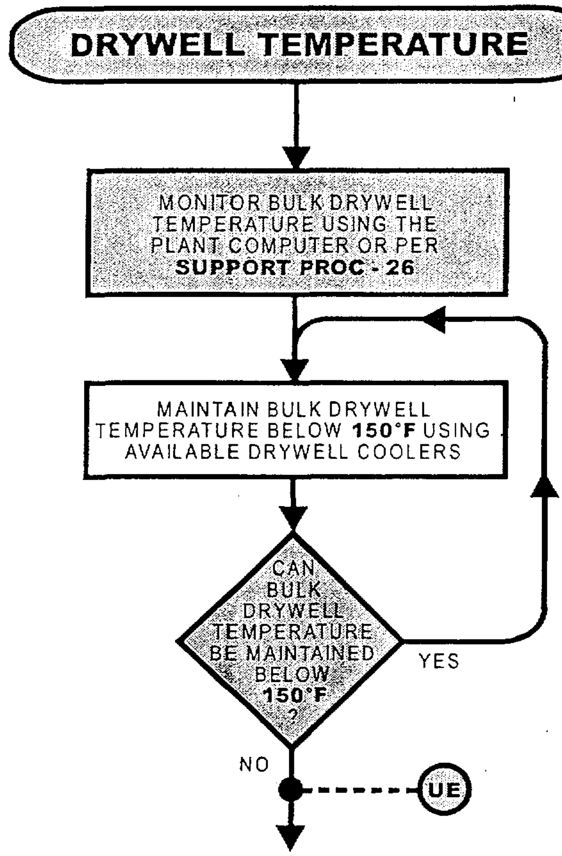
Question Source: Bank # ___
Modified Bank # ___ (Note changes or attached parent)
New X

Question Cognitive Level: Memory or Fundamental Knowledge X
Comprehensive or Analysis ___

10 CFR Part 55 Content: 55.41 X
55.43 ___

Comments:

DRYWELL TEMPERATURE CONTROL



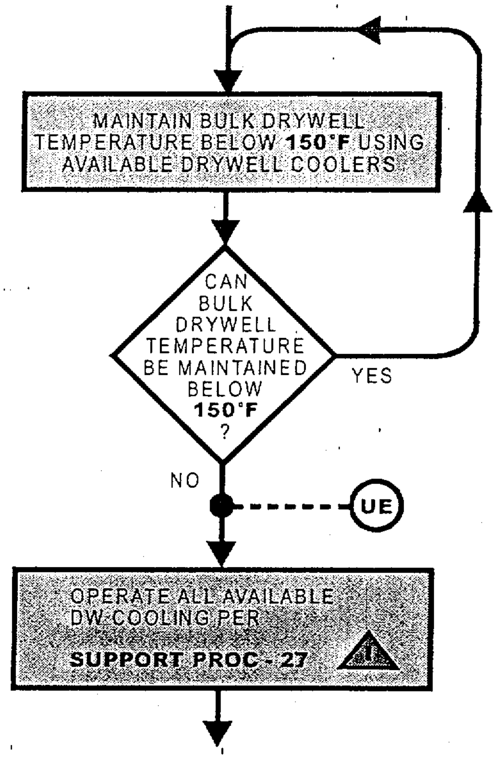
DISCUSSION

Normal system operating procedures provide instructions for controlling Drywell temperature during routine Plant operations, both shut down and at power. Under most circumstances, maintaining the required number of Drywell recirculation fans in operation, maintaining Drywell instrument nitrogen/air to support operation of the Drywell recirculation fan dampers, and maintaining a sufficient flow of cooling water to the Drywell coolers prevents excessive Drywell temperatures. The appropriate system lineups are established according to the following procedures:

- Procedure 312.9, Primary Containment Control, ensures four or five Drywell recirculation fans are in service.
- Procedure 309.2, Reactor Building Closed Cooling Water System, ensures at least one Reactor Building Closed Cooling Water (RBCCW) pump is running and one RBCCW heat exchanger is on-line.

Additionally, if Drywell temperature problems arise, Alarm Response Procedures and System Diagnostic and Restoration Procedure OPS-3024.09 prescribe actions that may be taken to maintain Drywell temperatures in the normal range.

DRYWELL TEMPERATURE CONTROL

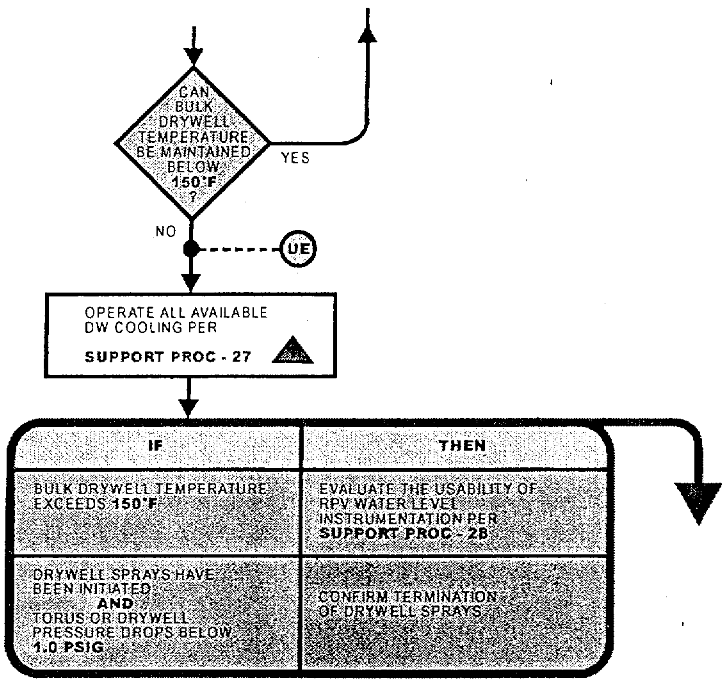


DISCUSSION

This question is asked if normal means of temperature control were adequate to maintain Drywell bulk temperature below 150°F. If normal methods were unsuccessful, then further actions are required.

Following the "DECISION" step is an Unusual Event flag. EPIP-OC-.01 recommends an Unusual Event Classification if Drywell bulk temperature is greater than or equal to 150°F, but less than or equal to 281°F for 5 minutes or longer.

DRYWELL TEMPERATURE CONTROL



DISCUSSION

If Drywell bulk temperature cannot be maintained below 150°F, cooling from all available Drywell coolers is maximized. Such actions may include:

- Operation of all five Drywell recirculation fans
- Operation of two RBCCW pumps and both RBCCW heat exchangers
- Operation of two Service Water pumps
- Maximizing Service Water flow to the RBCCW heat exchangers

These actions are performed at the discretion of the LOS.

The RBCCW system isolates upon the occurrence of either of the following conditions:

- Lo-Lo RPV water level AND high Drywell pressure
- Lo-Lo-Lo RPV water level

The pneumatic supply to the Drywell is required to maintain open the Drywell recirculation fan dampers. The Drywell pneumatic supply isolates on any one of the following conditions:

- Lo-Lo RPV water level
- Steam tunnel temperature at or above 180°F
- Any steam line flow at or above 4.0 mlbm/hr
- Reactor mode switch in RUN AND RPV pressure at or below 850 psig

Support Procedure -27 performs the following:

1) Defeats all isolation signals to the RBCCW Drywell isolation valves
2) Confirms open the RBCCW Drywell isolation valves
3) Starts all available Drywell recirc fans
4) Bypasses the Instrument Air Isolation valve, V-6-395 isolation signal and reopens the valve

Question 23

Answers "b" and "c" are both correct.

Answer "b" is consistent with ABN-26 guidance, to reduce reactor power and thereby reduce steam line activity. Since iodine production is proportional to reactor power, reducing power will have a direct impact on iodine production. Also, RAP 10F-2-d for Stack Effluent HI, directs actions IAW ABN-26. Therefore, answer "b" is procedurally driven from ABN-26, which dictates a power reduction to clear the alarms. Nowhere in the procedures does it have the operator removing normal reactor building ventilation and starting standby gas treatment system.

Answer "c" is also correct, because starting Standby Gas Treatment will remove radioactive iodine that is present under all conditions.

Therefore, answers "b" and "c" are correct.

References: RAP 10F-2-d, "STACK EFFLUENT HI"
ABN-26, High Main Steam Line or Off-Gas Activity

QUESTION #23

Given the following plant conditions:

- Reactor is at 100% power
- AOG is in service
- Main Steam Line Radiation Monitors all at approximately 550 mr/hr
- Stack Effluent HI alarm
- Reactor Bldg Vent Radiation at 8 mr/hr
- RCS activity at 90% of TS limit
- B" IC isolated for maintenance
- Significant/visible packing leak from "A" IC outboard steam isolation valve
- **NO** leaks in the "A" IC tube bundle

What action(s) would result in having the greatest reduction in the thyroid damage for the public?

A. Close "A" IC outboard steam isolation valve

B. Reduce reactor power until stack effluent HI alarm clears

C. Start SGTS and shutdown Reactor Building HVAC

D. Close "A" IC vent valve

ANSWER: C

EXPLANATION:
Starting SGTS is the only action that will remove radioactive iodine being released from the steam leak. The AOG will remove all iodine from the off gas regardless of reactor power so reducing power will not result in a reduction in iodine.

TECHNICAL REFERENCE(S): ____________ (Attach if not previously provided)

Proposed references to be provided to applicants during examination: None

Learning Objective: ____________ (As available)

Examination Outline Cross-reference:

Level	RO	SRO
Tier #	1	___
Group #	1	___
K/A #	295038/EK1.01	
Importance Rating	2.5	___

K/A Topic Description:
Knowledge of the operational implications of the biological effects of radioactive ingestion as it applies to Off Gas Release rate.

Question Source:
Bank # ____
Modified Bank # ____ (Note changes or attached parent)
New X

Question Cognitive Level:
Memory or Fundamental Knowledge ____
Comprehensive or Analysis X

Group Heading	
RADIATION MONITORS PROCESS STACK EFFLUENT	10F - 2 - d

STACK EFFLUENT HI	REFLASH

CAUSES:	SETPOINTS:	ACTUATING DEVICES:
(1) HI concentration of noble gas radioactivity in the main stack effluent.	1,000 cps	Ch. #1 RE-661-1621 VIA RIT-661-1615 VIA RYS-661-1615 Ch. #2 RE-661-1622 VIA RIT-661-1624 VIA RYS-661-1624 Reflash unit: PNL-661-1RAR3
		Reference Drawings: GU 3E-611-17-003 GU 3D-661-42-001

CONFIRMATORY ACTIONS:

Verify the high radiation level at the Stack RAGEMS noble gas effluent monitors on Panel 1R or Stack RAGEMS effluent recorders on Panel 10F. If the alarm is from a high concentration of noble gas in main stack effluent as verified from the Panel 10F Recorders, follow the manual corrective actions. If desired, contact Plant Chemistry to take a stack effluent noble gas sample.

If the primary containment was being vented, the source of the high stack activity may be from the primary containment. If the source of the activity is confirmed to be from the primary containment, the GSS shall insure the containment is vented through the Standby Gas Treatment System.

AUTOMATIC ACTIONS:

NONE

MANUAL CORRECTIVE ACTIONS:

Check for high radiation in the offgas stream, Reactor Building, Turbine Building, Old Radwaste, and New Radwaste, or trip of the Reactor Building Ventilation System and perform actions defined in Procedure 2000-ABN-3200.26, Increase in Offgas Activity.

Notify Chemistry of condition. The Offsite Dose Calculation Manual (ODCM 2000-ADM-4532.04, Section 4.6.1.1.5.c) may apply.

Prior Revision 0 incorporated the following Temporary Changes:

N/A

This Revision 0 incorporates the following Temporary Changes:

N/A

List of Pages

1.0 to 7.0

HIGH MAIN STEAM LINE OR OFF GAS ACTIVITY

1.0 APPLICABILITY

This procedure provides directions for abnormally high Main Steam line or Off Gas radioactivity release rates.

Section 3.1 Main Steam Radiation Levels 550 to 800 mr/hr

Section 3.2 Main Steam Radiation Levels greater than 800 mr/hr

Section 3.3 Rise in Off Gas Activity

2.0 INDICATIONS

2.1 Annunciators

Engraving	Location	Setpoint
OFF GAS HI-HI	10F-1-c	1,000 mr/hr
OFF GAS HI	10F-2-c	700 mr/hr
STACK EFFLUENT HI-HI	10F-1-d	2,000 cps
STACK EFFLUENT HI	10F-2-d	1,000 cps
RAD HI	J-5-b	550 mr/hr

2.2 Plant parameters

Parameter	Location	Change
Air ejector off gas radiation	Panel 10F, 1R	Rising
Stack effluent radiation	Panel 10F, 1R	Rising
Main steamline radiation	Panel 10F, 1R, 2R	Rising

2.3 Other indications – None

3.0 OPERATOR ACTIONS

If while executing this procedure, an entry condition for any EOP occurs,

then EXECUTE this procedure concurrently with the appropriate EOP.

3.1 Main Steam Radiation Levels 550 to 800 mr/hr

1. **If** two or more Main Steam Line Radiation Monitors, on Panel 1R and 2R are verified greater than 550 mr/hr, **but** less than 800 mr/hr,

   then PERFORM the following:

   A. **DIRECT** Chemistry to sample the Reactor coolant. [ ]

   B. **MONITOR** off gas and stack effluent activity. [ ]

   C. **If** Hydrogen Injection is in operation,

   then PERFORM the following:

   1. **REDUCE** Hydrogen Injection flow rate to between 5 and 6 scfm. [ ]

   2. **ALLOW** 10 minutes for the Main Steam RAD HI alarm (J-5-b) to clear. [ ]

   3. **If** Main Steam RAD HI alarm (J-5-b) clears within 10 minutes,

      then PERFORM the following:

      a. **MONITOR** off gas and stack effluent activity. [ ]

      b. **NOTIFY** Reactor Engineering of plant conditions. [ ]

4. **If** Main Steam RAD HI alarm (J-5-b) does **not** clear within 10 minutes, **and** fuel damage is confirmed by chemistry sample analysis and/or rising off gas activity, [ ]

   then COMMENCE plant shutdown in accordance with Procedure 203, Plant Shutdown.

5. **If** Hydrogen Injection is **not** in operation, **and** fuel damage is confirmed by chemistry sample analysis and/or rising off gas activity, [ ]

   then COMMENCE plant shutdown in accordance with Procedure 203, Plant Shutdown.

3.2 Main Steam Radiation Levels greater than 800 mr/hr

1. **If** two or more Main Steam Line Radiation Monitors, on Panel 1R and 2R are verified greater than 800 mr/hr, **and** off gas activity is rising, [ ]

   then SCRAM the Reactor in accordance with ABN-1, Reactor Scram.

2. **If** the Reactor has successfully scrammed,

   then CLOSE the following valves:

   - MSIVs [ ]
   - Isolation Condenser vents [ ]
   - Reactor Water sample valves V-24-29 and V-24-30 [ ]
   - Drywell Air Supply valve V-6-395 [ ]

3. **MONITOR** off gas and stack effluent activity. [ ]

4. **EVACUATE** the Turbine Building and/or the Reactor Building as directed by the US. [ ]

5. **REFER** to EPIP-OC-01, Classification of Emergency Conditions, for EAL evaluation. [ ]

6. **NOTIFY** Reactor Engineering of plant conditions. [ ]

3.3 Rise in Off Gas Activity

1. **If** Reactor power is greater than 40%, **and** off gas activity rises by more than 50% after factoring out any rise due to changes in thermal power,

   then PERFORM the following:

   A. **DIRECT** Chemistry to sample off gas and the Reactor coolant. [ ]

   B. **REFER** to Technical Specifications 3.6.E and 4.6.E. [ ]

   C. **REQUEST** guidance from Reactor Engineering. [ ]

2. **If** any of the following alarms are received,

   - OFF GAS HI (10F-2-c) [ ]
   - STACK EFFLUENT HI (10F-2-d) [ ]
   - STACK EFFLUENT HI-HI (10F-1-d) [ ]

   then PERFORM the following:

NOTE:	A change in any of the listed parameters may cause a fluctuation in the off gas release rate.

   A. **REVIEW** recent changes in any of the following parameters. [ ]

   - Off Gas line flow
   - Condenser vacuum
   - Steam seal header pressure

B. **NOTIFY** Chemistry of the condition. [ ]

C. **REDUCE** Reactor power until all three radiation alarms listed in Step 2 have cleared. [ ]

D. **If** all three radiation alarms listed in Step 2 **cannot** be cleared,

then DIRECT Chemistry to sample the Reactor coolant and off gas. [ ]

3. **If** the OFF GAS HI-HI alarm (10F-1-c) is received,

then PERFORM the following:

A. **VERIFY** off gas conditions. [ ]

B. **REDUCE** Reactor power until the OFF GAS HI-HI alarm clears. [ ]

C. **COMMENCE** plant shutdown in accordance with Procedure 203, Plant Shutdown. [ ]

D. **If** the OFF GAS HI-HI alarm does **not** clear within 15 minutes of actuation,

then PERFORM the following:

1. **SCRAM** the Reactor in accordance with ABN-1, Reactor Scram. [ ]

2. **CONFIRM** the following valves closed:

- Off Gas Exhaust Isolation Valve, V-7-31, on Panel 10XF [ ]
- AOG Inlet Valve, AOV-0001A/-0001B, on Panel 10XF [ ]

3. **PLACE** Drain Valves, V-7-29/SOV-016 control switch in the CLOSE position on Panel 10XF. [ ]

4. **If** the Reactor has successfully scrammed,

   then CLOSE the following valves

   - MSIVs [ ]
   - Isolation Condenser vents [ ]
   - Reactor Water sample valves V-24-29 and V-24-30 [ ]
   - Drywell Air Supply valve V-6-395 [ ]

5. **EVACUATE** the Turbine Building and/or the Reactor Building as directed by the US. [ ]

4. **REFER** to EPIP-OC-01, Classification of Emergency Conditions, for EAL evaluation. [ ]

5. **MONITOR** off gas and stack effluent activity. [ ]

6. **NOTIFY** Reactor Engineering of plant conditions. [ ]

4.0 **REFERENCES**

4.1 Technical Specifications

4.2 ABN-1, Reactor Scram

4.3 Procedure 203, Plant Shutdown

5.0 **ATTACHMENTS** – None

Question 25

Regarding core spray system availability per the Level Restoration procedure, all the EOPs are concerned with is main pump availability per each core spray system. The booster pumps are started with the US concurrence.

As it pertains to the core spray system, if the core spray sparger hi dp alarm is present, it only indicates the core spray system may not perform its design function of establishing a uniform spray pattern. RAP B-5-e and B-5-f (sparger dp hi alarms), list the cause of the alarm as high differential pressure across the sparger nozzles due to Core Spray line break in the vessel annulus. With the alarm in, it is assumed all core spray flow is diverted to the annulus. Even with this annulus flow, the core spray systems can be considered available as an injection source, and other mitigating actions will be based upon RPV water level at or above –30 inches. While it is absolutely true that the core spray system will not operate at design basis flows for spray cooling, this decision is not addressed until all actions have been taken to emergency depressurize and RPV water level cannot be restored and maintained above –30 inches. This condition is <u>NOT</u> what the question is asking.

Based upon the above argument, all four answers were assessed without any regard to sparger dp alarms.

For the remaining information in the question, the key to determining which set of conditions will result in core spray flow is the Flow Permissive signal. Per RAP B-2-e and B-2-f (SYSTEM 1/2 FLOW PERMISSIVE), the following conditions must be met:

- Booster pump dp signal for the respective core spray system, **AND**
- Core spray main pump discharge pressure, **AND**
- RPV pressure less than 305 psig

Based upon these criteria, answers "a" and "d" <u>CANNOT</u> be correct, as the booster pump overload trip affects its system, and the booster pump dp signal will <u>NOT</u> be generated, thereby eliminating the flow permissive signal for that system. However, both answers "b" and "c" are correct, as the booster pump trip affects the other system, allowing the flow permissive alarm to be received.

Therefore, answers "b" and "c" are correct.

References: RAP B-2-e, SYSTEM 1 FLOW PERMISSIVE
RAP B-3-e, BSTR PUMP A/C OL
RAP B-5-e, SPARGER 1 DP HI
RAP B-2-f, SYSTEM 2 FLOW PERMISSIVE
RAP B-3-f, BSTR PUMP B/D OL
RAP B-5-f, SPARGER 2 DP HI
EMG-3200.01A, RPV Control – No ATWS, Level Restoration
EOP User's Guide, pp. 1A-25 and 1A-39

QUESTION #25

Following a loss of offsite power, the crew has initiated EMG-3200.01A "RPV Control-No ATWS" and is at the step that specifies "Confirm the following sub-systems lined up for injection with pumps running".

Which of the following configurations of Core Spray annunciators **LIT** would confirm either Core Spray System 1 or Core Spray System 2 is lined up with pumps running?

A. SPARGER 1 DP HI, SYSTEM 1 FLOW PERMISSIVE, BSTR PUMP A/C OL

B. SPARGER 1 DP HI, SYSTEM 2 FLOW PERMISSIVE, BSTR PUMP A/C OL

C. SPARGER 2 DP HI, SYSTEM 2 FLOW PERMISSIVE, BSTR PUMP A/C OL

D. SPARGER 2 DP HI, SYSTEM 2 FLOW PERMISSIVE, BSTR PUMP B/D OL

ANSWER: B

EXPLANATION:
For A, C and D the sparger dp alarm indicates the sub-system that has the flow permissive (pumps actually running) is faulted and the flow may NOT be "lined up for injection" that is it may not be going into the RPV.

TECHNICAL REFERENCE(S): ______________ (Attach if not previously provided)

Proposed references to be provided to applicants during examination: ______________

Learning Objective: ______________ (As available)

Examination Outline Cross-reference:

Level	RO	SRO
Tier #	2	___
Group #	1	___
K/A #	209001/A2.05	
Importance Rating	3.3	___

K/A Topic Description:
Ability to predict the impacts of Core Spray Line Break on the Low Pressure Core Spray System and based on those predictions use procedures to correct, control or mitigate the consequences of those abnormal conditions or operations.

Question Source: Bank # ____
Modified Bank # ____ (Note changes or attached parent)
New X

Question Cognitive Level: Memory or Fundamental Knowledge ____
Comprehensive or Analysis X

10 CFR Part 55 Content: 55.41 X
55.43 ____

Comments:

Group Heading CORE SPRAY 1	B-2-e

SYSTEM 1 FLOW PERMISSIVE

CAUSES:	SETPOINTS:	ACTUATING DEVICES:
Booster pump differential pressure greater than 30.5/28.5 psid (RV40A/RV40C)	30.5 psid 28.5 psid	DPS RV40A or DPS RV40C
- AND -		- AND -
Core Spray pump discharge pressure greater than 100 psig	105 psig	PS RV29A or RV29C
- AND -		- AND -
Reactor pressure less than 305 psig	305 psig	RE17A or RE17B
<u>NOTE</u>: This alarm will activate only if all three conditions are met indicating that core spray should be injecting into the depressurized Rx core.		Reference Drawings: NU 5060E6003 Sh. 1 & 3 GU 3E-611-17-004 Sh. 1

CONFIRMATORY ACTIONS:

Check pump discharge pressures on Panel 1F/2F.

Check reactor pressure on Panel 4F.

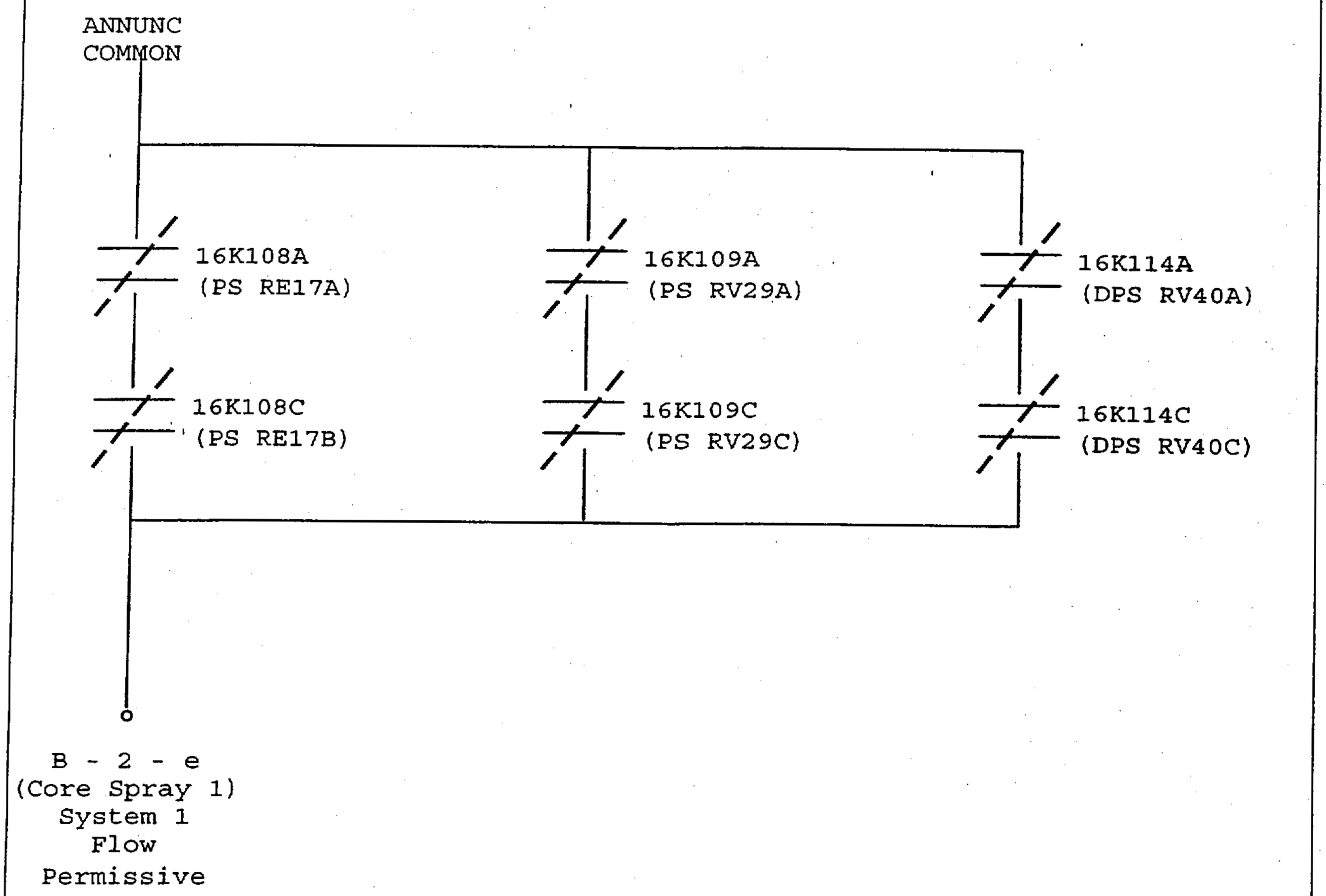
AUTOMATIC ACTIONS:

Core Spray pumps discharge pressure greater than 105 psig allows start of booster pump. Failure of booster pump to develop a differential pressure greater than 30.5/28.5 psid (RV40A/RV40C) within 5 seconds, trips booster pump and starts alternate pump. Reactor pressure less than 305 psig permits opening of Core Spray isolation valves with system initiation. <u>NOTE</u>: The alternate booster pump will not start automatically unless failure of both primary booster pumps occur.

MANUAL CORRECTIVE ACTIONS:

If alarm sounds and all three conditions are not met, repair switches if defective.

SYSTEM 1
FLOW
PERMISSIVE



Group Heading	
CORE SPRAY 1	B-3-e

BSTR PUMP A/C OL

CAUSES:	SETPOINTS:	ACTUATING DEVICES:
Core Spray booster pump, NZ03A or NZ03C, drive motor overload.	430 amps	49 / NZ03A or 49 / NZ03C
		Reference Drawings: GE 116B8328 Sh. 15A, 15B; GU 3E-611-17-004 Sh. 1

CONFIRMATORY ACTIONS:

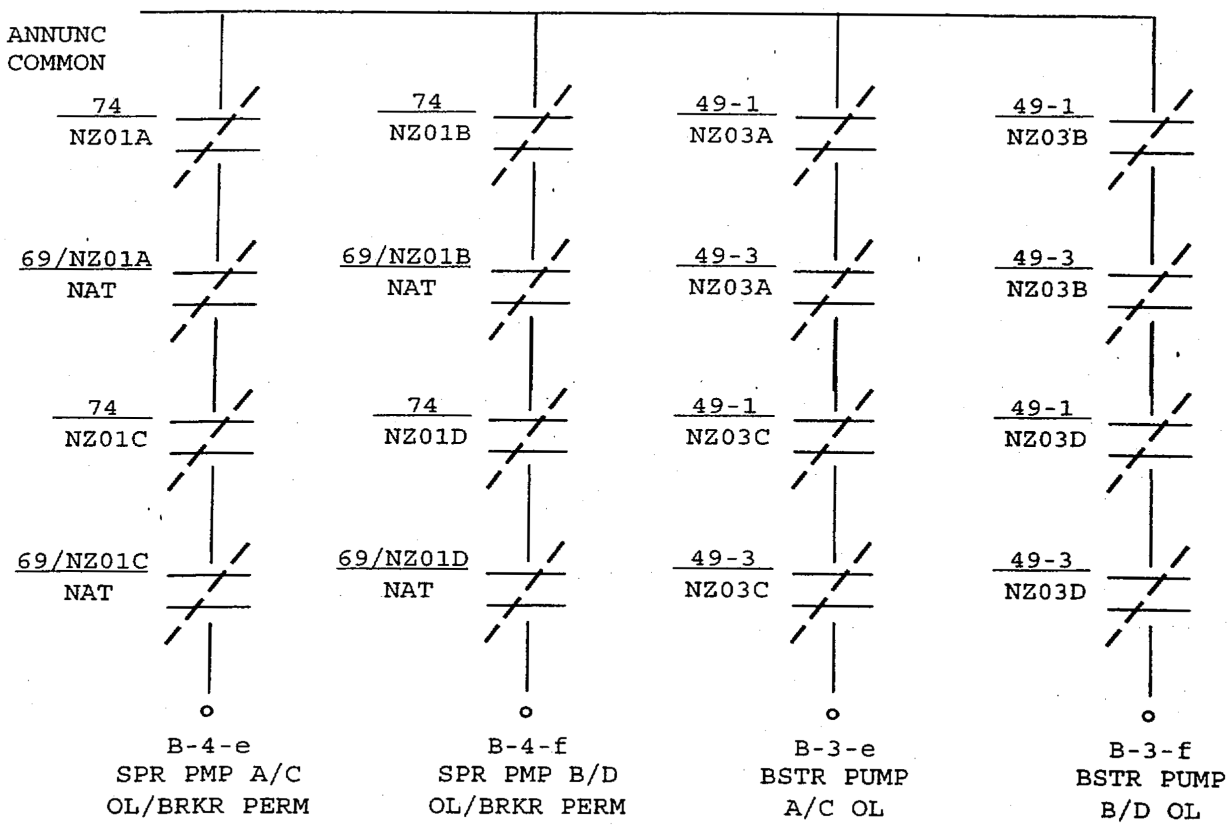
AUTOMATIC ACTIONS:

NONE

MANUAL CORRECTIVE ACTIONS:

Determine which pump is affected. Start alternate pump as required and trip affected pump. Refer to 2000-OPS-3024.07 "Core Spray System Diagnostic and Restoration Actions".

BSTR PUMP A/C OL



SPARGER 1
DP HI

CAUSES:	SETPOINTS:	ACTUATING DEVICES:
High pressure differential across Core Spray System 1 sparger nozzles due to Core Spray line break in the vessel annulus.	0.3 ± 0.3 psid	DPIS RV30A

Reference Drawings:

GE 148F712
GE 885D781
GE 112C2845 Sh. 3
GU 3E-611-17-004 Sh. 2

CONFIRMATORY ACTIONS:

Verify pressure differential at instrument rack RK04.

AUTOMATIC ACTIONS:

None

MANUAL CORRECTIVE ACTIONS:

If instrument reading is greater than or equal to 1 psid, consider Core Spray System 1 inoperable. Verify operability of System 2.
Notify Licensed Operations Supervisor. Core MAPLHGR must be brought within 90% of limit within 2 hours. Contact Core Engineering by referencing the Core Maneuvering Daily Instructions for guidance on rod movement and power changes.

Group Heading CORE SPRAY 2	B-2-f

SYSTEM 2 FLOW PERMISSIVE

CAUSES:	SETPOINTS:	ACTUATING DEVICES:
Booster pump differential pressure greater than 47.0/25.0 psid (RV40B/RV40D)	47.0 psid 25.0 psid	DPS RV40B or DPS RV40D
- AND -		- AND -
Core Spray pump discharge pressure greater than 100 psig	140 psig	PS RV29B or RV29D
- AND -		- AND -
Reactor pressure less than 305 psig	305 psig	RE17C or RE17D
<u>NOTE</u>: This alarm will activate only if all three conditions are met indicating that core spray should be injecting into the depressurized Rx core.		Reference Drawings: NU 5060E6003 Sh. 2 & 4 GU 3E-611-17-004 Sh. 1

CONFIRMATORY ACTIONS:

Check pump discharge pressures on Panel 1F/2F.

Check reactor pressure on Panel 4F.

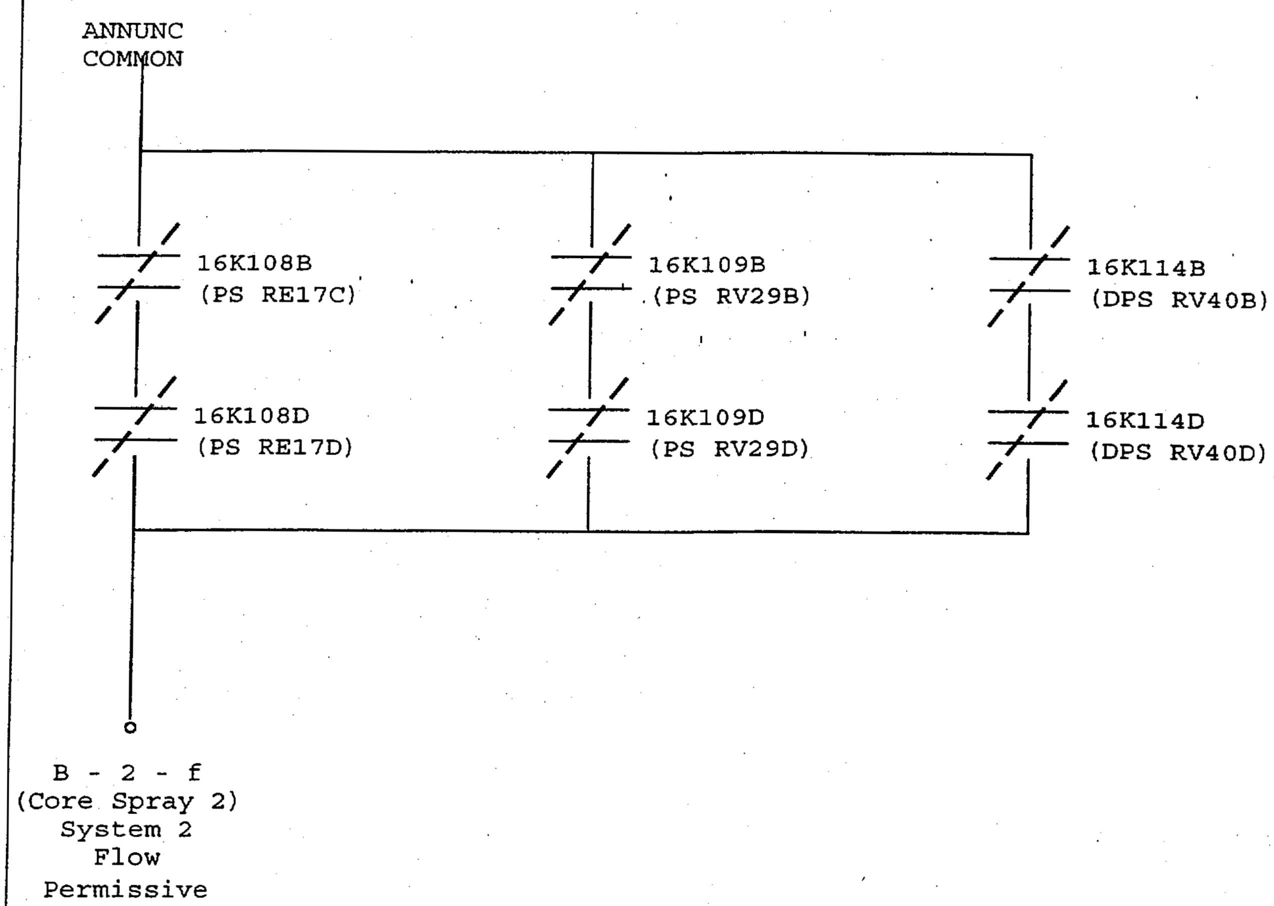
AUTOMATIC ACTIONS:

Core Spray pumps discharge pressure greater than 140 psig allows start of booster pump. Failure of booster pump to develop a differential pressure greater than 47.0/25.0 psid (RV40B/RV40D) within 5 seconds trips booster pump and starts alternate pump. Reactor pressure less than 305 psig permits opening of Core Spray isolation valves with system initiation. <u>NOTE</u>: The alternate booster pump will not start automatically unless failure of both primary booster pumps occur.

MANUAL CORRECTIVE ACTIONS:

If alarm sounds and all three conditions are not met, repair switches if defective.

SYSTEM 2
FLOW
PERMISSIVE



BSTR PUMP B/D OL

CAUSES:	SETPOINTS:	ACTUATING DEVICES:
Core Spray booster pump, NZ03B or NZ03D, drive motor overload.	430 amps	49 / NZ03B or 49 / NZ03D
		Reference Drawings: GE 116B8328 Sh. 15C, 15D; GU 3E-611-17-004 Sh. 1

CONFIRMATORY ACTIONS:

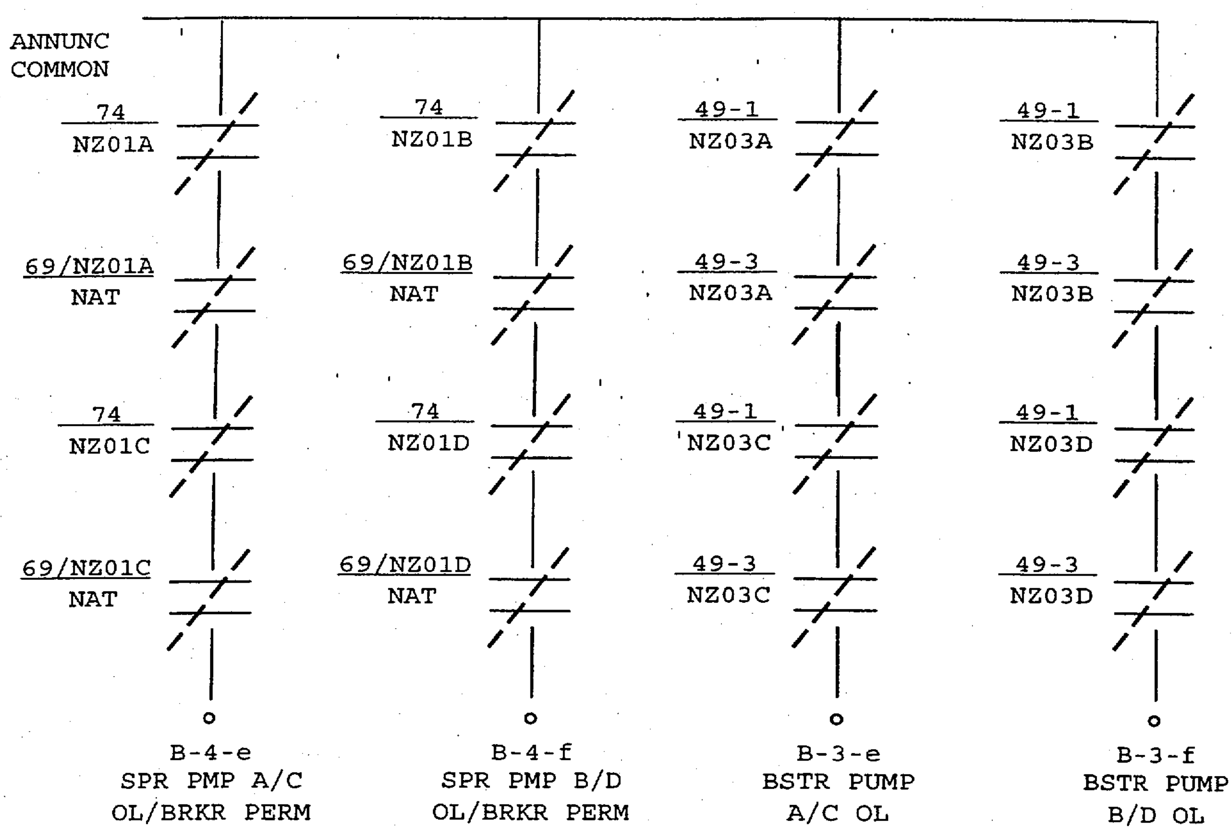
AUTOMATIC ACTIONS:

NONE

MANUAL CORRECTIVE ACTIONS:

Determine which pump is affected. Start alternate pump as required and trip affected pump. Refer to 2000-OPS-3024.07 "Core Spray System Diagnostic and Restoration Actions".

BSTR PUMP
B / D OL



Group Heading CORE SPRAY 2	B-5-f
SPARGER 2 DP HI	

CAUSES:	SETPOINTS:	ACTUATING DEVICES:
High pressure differential across Core Spray System 2 sparger nozzles due to Core Spray line break in the vessel annulus.	0.3 ± 0.3 psid	DPIS RV30B Reference Drawings: GE 148F712 GE 885D781 GE 112C2845 Sh. 3 GU 3E-611-17-004 Sh. 2

CONFIRMATORY ACTIONS:

Verify pressure differential at instrument rack RK04.

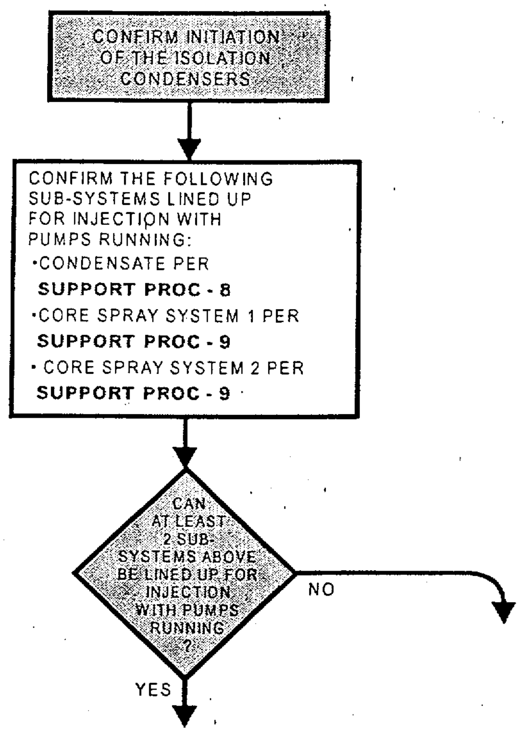
AUTOMATIC ACTIONS:

None

MANUAL CORRECTIVE ACTIONS:

If instrument reading is greater than or equal to 1 psid, consider Core Spray System 2 inoperable. Verify operability of System 1.
Notify Licensed Operations Supervisor. Core MAPLHGR must be brought within 90% of limit within 2 hours. Contact Core Engineering by referencing the Core Maneuvering Daily Instructions for guidance on rod movement and power changes.

RPV WATER LEVEL CONTROL (LEVEL RESTORATION)



DISCUSSION

The purpose of this step is to maximize the injection capability of the RPV injection subsystems. This is accomplished by confirming the correct system lineup, aligning the system for maximum flow, and confirming the pumps in the system are running in accordance with the applicable Support Procedure. Subsystem flow is maximized at this time to allow vessel makeup as pressure decreases below their respective shutoff heads. RPV pressure is reduced through either the RPV Pressure Control leg or from an emergency depressurization, which may be directed in subsequent steps. It is important to note that the direction to maximize flow at this point does not of itself authorize exceeding the 100°F/hr cooldown rate or provide a basis for anticipating emergency depressurization.

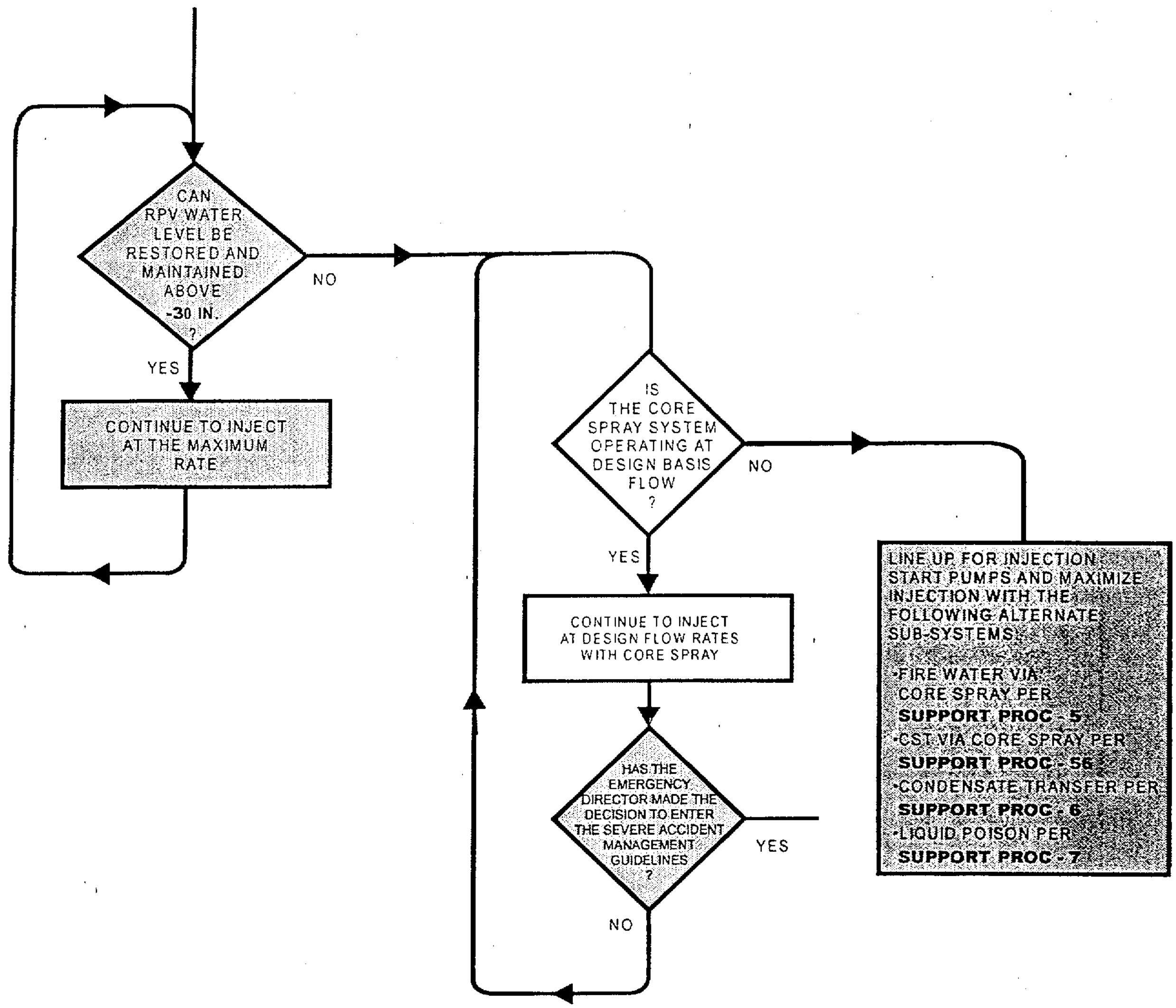
Core Spray System flow is maximized regardless of NPSH or Vortex limits. Restoring RPV water level to ensure adequate core cooling takes precedence over any potential damage to the pumps.

(Note - authorization to exceed NPSH and Vortex limits is given in the applicable Support Procedure by the omission of any direction to adhere to these limits.)

RPV injection subsystems are defined by the physical separation of components, flow paths, and injection points. An RPV injection subsystem, as identified in this step, is a motor-driven system loop that is capable of supplying makeup water to the RPV. Core Spray System 1, along with the flow path from the Torus to the RPV, forms one injection subsystem. The corresponding equipment in Core Spray System 2 forms a second subsystem. Any Condensate pump or pumps and a flow path from the Main Condenser hotwell through the Feedwater heaters and Feedwater Regulating Valves to the RPV constitute the third injection subsystem.

Support Procedure - 8 for the Condensate System, and Support Procedure - 9 for the Core Spray System provide instructions for confirming the correct subsystem lineups, aligning the subsystem for maximum flow, and confirming the pumps in the subsystem are running.

RPV WATER LEVEL CONTROL (LEVEL RESTORATION)



DISCUSSION

The Level Restoration steps have been expanded to include the Core Spray System operating as designed as a success path for alternate level control. This change permits reliance on design basis core cooling criteria in preference to low-quality injection and Primary Containment flooding. As long as RPV water level can be restored and maintained above the Minimum Steam Cooling RPV Water Level or design basis flow from the Core Spray System can be established and maintained, the core cooling will remain within design basis and no other action is immediately required. The "design basis" core cooling criteria is derived from information contained in the Plant FSAR.

Question #37

Per RAP H-6-A, ROD DRIFT, the cause is any control rod drifting more than 3" through an odd rod position, when the control rod is not selected. The RAP directs a scram if more than one rod is moving in or out abnormally. If only one rod is moving, it directs actions in accordance with ABN-6.

Per Technical Manual VM-RW-1316, Detailed Design Manual, Control Rod Monitor and Scan Routine, when a rod drift is detected, a 10-second timer starts. If the rod drifts for a period >10 seconds without the rod drift alarm clearing, RMCS will latch to the highest completed step having less than three insert errors and at least one rod withdrawn past the insert limit, making answer "c" correct. If the rod drift clears before the 10-second timer times out, then RMCS assumes it as a slow settling rod and the drift is determined to have cleared satisfactorily. In this case, the RWM will relatch with no insert errors and no withdraw errors, making answer "d" correct.

The operator actions of ABN-6 direct the operator to select the rod and apply a continuous insert signal to position 00. If the operator selects the drifting rod **before** the 10-second timer times out, the rod drift alarm will clear. While the actions for a drifting in control rod are not expected operator actions, it IS operations management expectations for the URO to identify and select the drifting rod for two reasons. First, it is easier to monitor the drifting rod once it has been selected. Second, if the drifting rod has been selected, **and** the rod drift alarm does NOT clear, this is indicative of more than one rod drifting, which requires a manual reactor scram. If the rod drift alarm clears when it is selected, then only one rod (the selected rod) can be drifting. At that point, the operator will break out ABN-6, go to the section for a drifting in control rod, and carry out the actions specified.

The students were taught to immediately select the identified rod that is drifting, for the above reasons. They were subjected to numerous drifting control rods during their training. Since Oyster Creek utilizes a full core display that shows all 137 control rod positions on the vertical section of Panel 4F, a drifting control rod is usually spotted within a few seconds, and it is not at all unlikely the rod will be selected before the 10-second timer has timed out.

Based upon when the drifting rod is selected, answers "c" and "d" are correct.

References: Rod Worth Minimizer lesson plan
VM-RW-1316, RWM DETAILED DESIGN MANUAL, sections 3.5.2.3, 3.11.1, and 3.11.3.3
ABN-6, Control Rod Drive System
RAP H-6-a, ROD DRIFT

QUESTION #37

Following a rod drifting in, the RWM will "relatch".

RMCS will locate the highest completed step that meets which one of the following criteria?

A. LESS THAN three insert errors and MORE THAN two rods are withdrawn past the insert limit.

B. **NO** insert errors and AT LEAST one rod is withdrawn past the insert limit

C. LESS THAN three insert errors and AT LEAST one rod withdrawn past the insert limit.

D. **NO** insert errors and **NO** withdraw errors

ANSWER: [redacted]

EXPLANATION:
Obtained from OC Training as a bank question used previously.

TECHNICAL REFERENCE(S): RWM Lesson Plan (Attach if not previously provided)

Proposed references to be provided to applicants during examination: None

Learning Objective: (01) 10446 (As available)

Examination Outline Cross-reference:

Level	RO	SRO
Tier #	2	
Group #	2	
K/A #	201006/K4.06	
Importance Rating	3.2	

K/A Topic Description:
Knowledge of Rod Worth Minimizer design feature(s) that permit correction of out of sequence rod positions

Question Source: Bank # X
Modified Bank # ____ (Note changes or attached parent)
New ____

Question Cognitive Level: Memory or Fundamental Knowledge X
Comprehensive or Analysis ____

10 CFR Part 55 Content: 55.41 X
55.43 ____

Comments:

2.5.1.8 Task Names

These parameters define the names of all tasks sending or receiving messages in the RWM System. These are the names used by the Task Builder (TKB) when the tasks are built and used by the system message facility to pass messages between RWM tasks. These parameters are RAD50 for actual use with system service calls. RAD50 is a method used by the Digital Equipment Corporation for storing three bytes of selected character data in two bytes instead of the normal three.

Task names as currently defined in the system are as follows:

PZDAS	'DAEXEZ'	Data Acquisition Subsystem
PZMMI	'MMEXEZ'	Man/Machine Interface Subsystem
PZARS	'DREXEZ'	Data Archival/Retrieval Subsystem
PZCRM	'CRMEXZ'	Control Rod Monitor and Scan
PZCOM	'COMTKZ'	PCS Communications Subsystem
PZSQE	'SEQEDZ'	Sequence Editor
PZDBE	'DBEDTZ'	Database Editor
PZCSL	'CONSLZ'	Console terminal message receiver.

2.5.1.9 Message Argument Offsets

These parameters define the offsets into an array for building the intertask messages. The arrays used for the messages must necessarily be local to the routine sending the message.

PIMNO = 1	Message number
PINUM = 2	Number of arguments
PIAR1 = 3	Argument 1
PIAR2 = 4	Argument 2
PIAR3 = 5	Argument 3
PIAR4 = 6	Argument 4
PITM1 = 11	Time word 1: (year, month)
PITM2 = 12	Time word 2: (day, hour)
PITM3 = 13	Time word 3: (minute, second)

1 TICK = 1/64 SEC

2.5.1.10 Timers

These parameters define the number of ticks CRMS is required to wait before initiating a full core scan under the scram and rod drift conditions. These parameters are defined as follows:

PT1TMR = 600	10 Second Offset for rod drift to clear
PT2TMR = 600	10 Second Offset for rod drift to remain clear
PTSCRM = 600	10 Second Offset after scram to full core scan

3.3.3 Digital Equipment Corporation, RSX-11M/M-Plus, Version 4.2, Volume 4C, Executive Reference Manual

3.4 GENERAL DESCRIPTION OF CRMS

3.4.1 CRMS Overview

CRMS performs an initialization routine at the time of RWM system initialization by a cold or warm boot of the RWM system computer. The CRMS initialization routine serves to test the operation of the RWM block/permissive function and initialize local variables within CRMS .

In conjunction with CRMS initialization, the DAS subsystem is prompted to perform a full core scan to provide an update of the current control rod positions. Upon the completion of the full core scan as determined through the status of the full core scan request flag in the global CVT, CRMS obtains the updated rod positions from the CVT and attempts to "latch" to the prescribed Low Power sequence. **(The RWM boots in Lower Power Mode by default.)** The latching operation consists of the determination of the sequence step corresponding to the current control rod pattern. Once the sequence has been latched, CRMS can compare present control rod positions to those required, identify existing errors and initiate control rod blocks as warranted.

During execution, CRMS monitors control rod position through either of two modes. The normal mode of operation is designated "Operator Follow Mode". In this mode of operation, CRMS tracks changes in RWM system input data resulting from normal control rod positioning by the plant operator. However, a need for a full core scan update of rod positions may periodically become apparent based on triggering events (e.g., rod drift alarm activation, reactor scram initiation, etc.) or through request by external sources. In such instances, the "Scan Mode" of operation is active and CRMS obtains updated position information for all control rods upon the completion of a full core scan by the DAS subsystem.

Within the realm of plant operation requiring activation of the sequence monitoring function, latching logic is required for the determination of the proper latched sequence step. **Under Low Power Mode,** in-step latching is accomplished as part of the operator follow mode. Each new sequence step is initiated through selection of control rods at the reactor manual control panel. Under certain conditions including the occurrence of a full core scan or the occurrence of specific changes in plant operation, relatching to the prescribed sequence is necessary. The CRMS module seeks to find the proper sequence step corresponding to current control rod positions by performing a search for the highest step completed without encountering an insert block condition. Instances during normal RWM system operation in which a relatch is required include the following:

- o RWM System Initialization
- o RWM System Unbypass
- o Following Rod Drift Timer Expiration
- o Following Operator Rod Test Request
- o Following Correction of an Existing Insert or Withdraw Error
- o When Power Drops Below LPAP
- o When Power Drops Below LPSP
- o Following any Full Core Scan (Power Less Than LPAP)
- o On a timed interval during operation in the transition zone (Power between LPSP and LPAP setpoints)

Utilizing the rod position input data and sequence latching logic detailed above, CRMS establishes a basis for the performance of the sequence monitoring function. The sequence monitoring function generally serves to enforce the required sequencing constraints identified through the engineer-defined sequence and **under Low Power Mode,** BPWS rules. Exceptions to this condition exist concerning the loading of special shutdown margin or test sequences and during activation of the rod test request. **Under Low Power Mode,** whenever a shutdown margin or test sequence is loaded in global, BPWS constraints are suppressed and rod sequencing is determined by the engineer-defined sequence alone. BPWS constraints may also be suppressed via the VT-220 Man-machine function, as the engineer defined sequence longer enforce adherence to prescribed sequencing constraints. Under operating conditions above the LPAP or whenever the RWM system is placed in bypass by the plant operator, Low Power sequence monitoring shall cease to be active.

Sequence monitoring, however, is available above the LPAP, but requires manual activation by the Control Room Operator. Power Operations Mode may be activated to enforce a Power Operations Mode sequence at any power level while the RWM bypass switch is in the normal position, and Power Operations Mode (POM) has been started, and the POM sequence has been loaded.

Exceptions to this functional logic for sequence monitoring activation include conditions involving reactor scram initiation, bypass of the LPAP status within the RWM system programming and request of the rod test sequencing constraint by the plant operator.

During the performance of the sequence monitoring function, the CRMS subsystem controls rod block status data located in the global CVT to enforce the prescribed sequence for rod movement as necessary. For normal **Low Power** plant operation below the LPSP, control rod movement shall be required to follow sequencing constraints established by an engineer-defined sequence and Banked Position Withdrawal Sequence (BPWS) rules. Whenever any change is detected in control rod position which exceeds bounds established for the prescribed sequence (2 insert errors or 1 withdraw error), corresponding control rod motion is blocked except for the correction of existing errors.

Under Power Operations Mode, control rod movement shall be required to follow sequencing constraints established by an engineer-defined POM sequence. The POM sequence and its enforcement differ from the Low Power Mode as follows:

- **Low power groups (Groups 1-1 through Groups 4-1) may not be defined and therefore may not be moved under Power Operations Mode.**
- **Individual control rods may be defined and therefore moved under Power Operations Mode.**
- **Only one insert error is allowed under Power Operations Mode.**
- **Under Power Operations Mode, a select error generates both insert and withdraw blocks.**
- **The Power Operations Mode sequence has only 10 steps, and will only latch to Step 1, as the sequence is not reversible. Once Step 1 is complete, and a rod in Step 2 is selected, the sequence is updated deleting Step 1 and moving up all the remaining steps. A relatch is then performed against the new Step 1.**
- **Under Power Operations Mode, rod movement is monitored against the current step only.**

Under either mode, CRMS provides appropriate messages for existing error and block conditions required by the MMI, COMTASK and ARCHIVE subsystems.

3.3 REFERENCES

3.3.1 GPUN Oyster Creek, Rod Worth Minimizer, Functional Specification, Document No. 100-8500001-06

- Section 2.6.3, Control Rod Position and Scanning Program
- Section 2.6.4, Sequence Monitoring Program
- Section 2.6.9, RWM Performance Requirements

3.3.2 NEDO-21231, Banked Position Withdrawal Sequence

3.5.2.2 Communications

Communication between the various subsystems of the RWM shall be accomplished through the global tables and RSX message facilities.

3.5.2.3 Timers

The term timer has two connotations within the CRMS routine. The first connotation is associated with the timed intervals mode of execution. Timer as used here refers to a system service call to "wake up" CRMS at a specified

future time through the system mark time service. (See reference 3.3.2). The second connotation occurs in the context of "checking" a timer. Timer as used here requires only a system service call to determine the current time. This type of timer is started by making a call to the TIME service and saving the time returned in a local variable. Subsequent passes of CRMS "check" the timer by making another call to the TIME service and calculating the difference between the current system time and the saved system time. All of these type of timers have an associated time offset. (i.e., T1 and T2 as defined in Chapter 2, Section 2.5.1.10). These timers are said to have expired when the difference between the current and saved system times is greater than the specified offset.

3.5.3 Data Interfaces

CRMS works with data at both the global and local levels to perform the functions required of the CRMS routine.

3.5.3.1 Global Data

At the global level, CRMS is reading from and writing to the current value table (which contains the current value and quality code) as well as the MMI communications tables. The complete list of global variables may be found in Chapter 2 and is not presented here. However, the global variables used by a COS module for input and output are identified within the sections provided below for each individual COS module.

3.5.3.2 Local Data

At the local level, CRMS requires at a minimum one variable per COS module. These variables will be used in one of two ways. For the modules associated with the on-demand type of execution, one pass is needed to process the module completely. In these cases the local variable is set equal to the state of the trigger variable, the conditions are processed, and the module is skipped in subsequent passes until another COS occurs. For the modules associated with the timed intervals execution, multiple passes are required to process the module completely. In these cases, the local variable is set equal to the state of the global variable at the first COS, and the initial pass processing is done. Subsequent passes will perform the timed sequence steps as needed, and the local variable will set equal to the trigger variable only when The trigger variable has returned to it's original value and all requirements of the COS have been met.

3.5.4 Special Interfaces

CRMS shall use distinct modules for checking and enforcement of the Banked Position Withdrawal Sequence (BPWS). Refer to Section 3.2 and Appendix A for a more thorough treatment of BPWS.

3.10.3 Detailed Description

3.10.3.1 Global Inputs

GLOBAL	COMMON VARIABLE	VARIABLE NAME
LDEUG	(PSCRM)	Scram signal
LDEUG	(PDRFT)	Rod drift signal

The scram timer parameter will be used for the ten second timer as described in Chapter 2, Section 2.5.1.10.

3.10.3.2 Global Outputs

None

3.10.3.3 Method

The scram COS module is entered on the first scram COS and on each subsequent pass by CRMS until both the scram and rod drift signals have cleared. Each pass of CRMS performs one of the following submodules. This is a timed interval module.

3.10.3.3.1 Initial COS

On the first detection of the scram signal being set, CRMS retains the set state, starts a ten second timer, and notifies the appropriate tasks through the message facility of the scram.

3.10.3.3.2 Timer

On subsequent passes, CRMS checks the timer until it has expired. At that point, the first of two full core scans is requested.

3.10.3.3.3 Verification

After the initial full core scan, CRMS checks the state of both the scram signal and the rod drift alarm. When both are clear, a second full core scan is requested, a scram reset message is sent through the message facility, and the reset state of the scram signal is retained so that subsequent passes of CRMS will ignore this module until the next scram COS. A check on the local rod drift variable is also performed at this point, and that variable is reset as needed to avoid a third full core scan request from the rod drift COS module.

3.11 ROD DRIFT COS (CRDRFT)

3.11.1 Purpose

The rod drift signal is a field input point converted by the DAS subsystem to a logical variable in global common. The rod drift signal explicitly defines to CRMS that a full core scan and rod block requests are to be made if the rod drift has not cleared within a T1 time period. Additionally, a second full core scan request is to be made after the drift has been clear for a T2 period of time and the first full core scan has been completed. Should the scram and rod drift signals both be present, the scram signal takes precedence.

3.11.2 Requirements

The rod drift status COS module fulfills the following requirements:

- o detects a COS on the rod drift status
- o A message indicative of the rod drift is sent through the message facility
- o employs two time offsets, T1 and T2, to avoid unneeded or excessive full core scans
- o initiates a full core scan at time T1 after the rod drift COS is detected
- o initiates a second full core scan after the rod drift status has been clear for a time T2

3.11.3 Detailed Description

3.11.3.1 Global Inputs

GLOBAL	COMMON VARIABLE	VARIABLE NAME
LDEUG	(PDRFT)	Rod drift signal
LDEUG	(PSCRM)	Scram signal

Note: The T1 and T2 time offsets are incorporated as parameters as defined in Chapter 2, Section 2.5.1.10.

3.11.3.2 Global Outputs

None

3.11.3.3 Method

The rod drift alarm COS will be entered when the rod drift alarm change of state is first detected and on each subsequent pass until the rod drift has cleared satisfactorily. Each pass of CRMS performs one of the following submodules. This is a timed interval module.

3.11.3.3.1 Initial COS

On the first detection of a rod drift COS, a T1 timer is started. the state of the rod drift alarm is retained by CRMS, and the appropriate tasks are notified of the drift through the message facility.

3.11.3.3.2 Drift Determination

On subsequent passes, CRMS checks to see if the T1 timer is expired or the rod drift alarm is cleared. Should the T1 timer expire prior to clearing the rod drift signal, the T2 timer is started and two requests are made. The first request is to the rod blocks request COS to remove the insert and withdraw permissives. The second request is to the full core scan request COS module to initiate a full core scan. Should the rod drift clear before the T1 timer expires, a slow settling control rod is assumed and the drift is determined to have cleared satisfactorily.

3.11.3.3.3 Verification of Position Following Rod Drift

This last submodule is entered on all subsequent passes of CRMS after the T1 timer expiration processing is completed as detailed above. Each pass causes CRMS to check the rod drift status and the T2 timer. The T2 timer is restarted each pass in which the rod drift alarm is not clear. A second full core scan request is made when the first full core scan has completed and the T2 timer has expired. and a request to the rod block COS module is generated for the application of the insert and withdraw permissives.

Re Eng Trng

FILE

Exelon Nuclear

Course/Program:	NUCLEAR PLANT OPERATOR INITIAL	Module/LP ID:	2611-PGD-2621
Title:	©ROD WORTH MINIMIZER	Course Code:	828.0.0041
Author:	N. Boulware	Revision/Date:	04-12/27/02
Prerequisites:	None	Revision By:	N. Boulware
		Est. Teach Time:	~4 hours

Qualified Nuclear Engineer Review (If applicable):	[signature]	Date:	1/16/03
Training Supervision Review:	[signature]	Date:	1-16-03
Line Management Approval:	[signature]	Date:	1/16/03.

OBJECTIVES

From memory unless otherwise indicated and in accordance with the lesson plan, the trainee shall be able to:

Objective #	Objective Description	Pg. #
A. (01)10435	Given plant operating conditions, describe or explain the purpose(s)/function(s) of the system and its components.	2,6,7,14
B. (01)10446	Identify and explain system operating controls/indications under all plant operating conditions.	3-9,11
C. (01)10453	Explain or describe how this system is interrelated with other plant systems.	3,7,17
D. (01)10444	Describe the interlock signals and setpoints for the affected system components and expected system response including power loss of failed components.	4,14
E. (01)10447	Given normal operating procedures and documents for the system, describe or interpret the procedural steps.	8,18,20
F. (01)10451	Given Technical Specifications, identify and explain associated actions for each section of the Technical Specifications relating to this system including personnel allocation and equipment operation.	20

Exelon Nuclear

References:

A. Procedures:

1. 201, "Plant Startup"
2. 218, "Operation Below 10% Rated Power with the Rod Worth Minimizer Bypassed or Inoperable"
3. 409, "Operation of the Rod Worth Minimizer"
4. SO #2
5. SO #4
6. 106.11, "Reactivity Management

B. Technical Specifications:

1. Section 3.2.B.2

C. Drawings:

1. BR E015, RWM Patch Panel ER-653-089 Assy & Conn., Rev. 6
2. GE 237E912, RMCS Elementary Diagram, Sheets 1, 4, 5, & 8
3. GE 729E838, RWM System, Sheets. 1, 2, 3
4. GE 706E212, Rod Block Display
5. GU 3E-653-18-1000, RWM Conn. Diagram

D. Other:

1. OCNGS Updated FSAR, Section 7.7.1.3
2. NEDO-21331 "Banked Position Withdrawal Sequence"
3. SOER 84-2
4. LER 90-003 (OTDAITS # 900579)
5. VM-RW-1312, RWM Operator's Manual

Greg Bates

Lesson Description:

Approximately 4 hours of classroom lecture/discussion.

9. CRMS System Status Flags

   a. Initialization Request - initiates CRMS activities required to properly initialize the RWM System.

   b. Full Core Scan Request - used by CRMS to detect performance of core scan by DAS.

   c. Relatch Request – CRMS evaluates the proper sequence step corresponding to present rod positions.

   Relatches to currently loaded rod sequence.

   d. Rod Test Request - CRMS attempts to enter Rod Test mode.

      1) All rods must be fully in.

      2) allows operator to select and withdraw any single control rod regardless of sequence loaded.

      3) allows full utilization of one-rod-out permissive function without bypassing RWM.

   e. Inoperable Rod Request - allows inoperable rods to be removed from normal sequencing requirements. CRMS manages the status of control and operability.

F. Control Rod Sequencing

LO B,E

1. Six separate sequences available - test, shutdown margin, and four standard operating sequences (A1,A2,B1,B2)

2. Sequences are detailed through an engineer defined sequence (EDS) using sequence editor.

3. When any A or B sequence is loaded, CRMS checks for conformance to Banked Position Withdrawal Sequence (BPWS) rules.

4. Engineer Defined Sequence

   a. Stepwise listing of rod withdrawals.

   b. Each step identifies:

      1) a rod or group of rods to be withdrawn (or inserted), and

      2) insert and withdraw limits for rod motion.

   c. EDS always begins from all-rods-in.

d. Test and shutdown margin sequences - stepwise withdrawal of individual rods.

e. Standard operating sequences - stepwise withdrawal for groups of rods.

5. Banked Position Withdrawal Sequence (BPWS)

a. Set of rules for banked motion of rods in the core, which reduces rod worths to levels consistent with analyzed reactor safety limits.

b. Rules establish constraints for a defined set of ten rod groups.

"Black and white" pattern; rods are alternately full-in and full-out.

1) One set of rules for groups 1 through 4, below 50% rod density,

2) another set of rules for groups 5 through 10, above 50% rod density.

c. EDS is checked for conformance to BPWS when:

1) EDS is edited, and

2) when EDS is loaded into RWM.

Done by CRMS continuously.

6. Sequence Monitoring Operations

LO B

a. Performed by CRMS.

b. CRMS must "latch" to proper sequence step; done by comparing present rod positions to desired rod sequence.

c. When proper sequence step is established, CRMS uses rod block to enforce sequence.

d. Sequence latching performed in-step during normal operations: latched step is increased or decreased based on selection and/or movement of rods by operator.

e. Relatch occurs when proper step is unknown or requires re-evaluation due to changing plant conditions.

1) RWM System initialization

2) RWM System unbypass

3) Following a core scan

Power must be below LPSP.

4) Following correction of insert or withdrawal errors

5) Following rod drift timer expiration — **Rod drift reset.**

6) Following operator request

7) When power drops below LPAP

8) When power drops below LPSP

f. During relatch, CRMS attempts to determine step by comparing number of rod notches withdrawn to notch withdrawals required by the sequence.

   1) If step can be determined without identifying insert or withdrawal errors, relatch is complete.

   2) If not possible, step is determined by more detailed search of rod sequence.

g. When insert or withdrawal errors exist, CRMS finds the highest completed sequence step such that: — **During relatch.**

   1) less than three insert errors exist, and

   2) at least one rod in the step is withdrawn past the step insert limit.

   3) Results in a relatch to highest sequence step allowable without RWM insert block.

h. Once relatch completed, in-step latching is performed.

Conduct Interim Summary.

Content/Skills	Activities/Notes
IV. Controls, Interlocks, and Alarms	
A. Control Room Touch-screen CRT Display	**LO B** **Slide of Figure 41-4**
1. Sequence Display Information	
a. Upper left corner of screen provides:	
1) Current sequence step	
2) Group and subgroup identification	
3) Selected rod identification and position	
4) Insert and withdraw limits	
5) Separate block shows loaded sequence.	
b. Upper-center blocks provide:	
1) Rod having insert errors (total of two) or withdraw error (total of one)	
2) Next rod for insert or withdrawal.	
c. Selected rod and position always updated.	
d. Other information only updated during sequence monitoring operations.	
2. System Status Indications	**Slide of 41-4** **Q: How would the operator know a rod scan was in progress?** **A: Rod scan button turns red.**
a. Low Power Setpoint (LPSP) - Green when below the LPSP; red when at or above the LPSP.	
b. Rod Scan - Green when no core scan is in progress; red during performance of full core scan.	
c. RWM Bypass - Green when keylock switch is in "NORMAL;" red when the switch is in "BYPASS."	
d. Communication Link - Green when link between RWM and plant computer in functional; red when the link fails.	
e. Select Error - Green with no select error; red when a select error exists.	
f. Insert Block - Green when no insert block exists; red when an inset block develops.	
g. Withdraw Block - Green when no withdraw block exists; red when a withdraw block develops.	

3.2 SYSTEM INPUT AND SEQUENCE MONITORING FUNCTION

3.2.1 CRMS Subsystem Functional Overview

The Control Rod Monitor and Scan (CRMS) subsystem provides the means to monitor the change of state of key RWM system inputs and direct performance of the sequence monitoring function. CRMS also serves as a source of RWM system status information required by other RWM software subsystems.

CRMS polls the data maintained in computer memory upon the activation of computer system event flags triggered by DAS. These event flags are used to notify the CRMS subsystem whenever a change of state is detected in RWM system inputs by DAS. In this manner, CRMS determines changes in control rod selection, position and selected system inputs as the changes occur.

System input data monitored by CRMS is generally required to determine the activation of sequence monitoring requirements and identification of necessary sequence monitoring input. However CRMS also performs input monitoring functions of importance for other RWM software subsystems. The CRMS subsystem generates RWM system messages following the change of state of key RWM system inputs which are accessed by both the ARCHIVE and PCS subsystems. As a result, monitoring of RWM system inputs is always maintained by CRMS regardless of the need for sequence monitoring activites.

The CRMS subsystem also performs numerous system input and sequence monitoring functions on demand from other RWM software subsystems. These activities are keyed to changes in RWM system status flags maintained in computer memory.

3.2.2 Input Monitoring Operations

The CRMS subsystem monitors the status of several key system inputs on a continuous basis during RWM system operation. These system inputs include the following:

- Bypass Switch Position
- Low Power Setpoint (LPSP) Status
- Low Power Alarm Point (LPAP) Status
- SCRAM Signal Status
- Rod Drift Signal Status
- Rod Selection Input
- Rod Position Input

The bypass switch position and LPSP/LPAP status inputs are used by CRMS to determine whether sequence monitoring functions are required active. Whenever the system bypass switch is in the "normal" position and power remains below the LPSP, RWM system sequence monitoring activities are required. The CRMS subsystem monitors the sequence of control rod movement by the operator under these conditions and enforces the prescribed rod sequence. As reactor power is increased to a level between the LPSP and LPAP (transition zone), CRMS continues to monitor rod movement but ceases to enforce the sequence. Under operating conditions above the LPAP or whenever the RWM system is placed in bypass, all sequence monitoring functions cease to be active.

The reactor SCRAM and rod drift inputs are used by CRMS to trigger requests for full core scans of control rod position. This ensures that actual control rod positions are reflected in computer memory.

A full core scan of control rod positions is requested by CRMS following a ten second delay after the detection of a rod drift condition. At that point the CRMS subsystem also sets the rod blocks to prohibit control rod motion. A second full core scan is requested following a ten second delay after reset of the control rod drift.

During reactor SCRAM conditions, a subsequent rod drift condition is generally obtained due to control rod overtravel. The CRMS logic processes the reactor SCRAM signal in preference to the rod drift input resulting in a full core scan request from CRMS following a ten second delay after the detection of the reactor SCRAM. A second full core scan is requested following reset of both the SCRAM and rod drift inputs.

Monitoring of control rod selection and position inputs is always maintained by CRMS when the RWM system is in operation. These inputs are monitored in two seperate modes by CRMS. The normal mode of operation is designated as the "operator follow mode". In the operator follow mode, CRMS tracks changes in rod selection and position inputs as they occur during control rod selection and positioning by the operator. The second mode of operation is designated as the "scan mode". In the scan mode, CRMS obtains updated position information for all the control rods in the core following the completion of a full core scan by DAS.

3.2.3 System Status Flag Monitoring

As detailed above, CRMS subsystem operation is also keyed to numerous RWM system status flags. These system status flags include the following:

- Initialization Request Status
- Full Core Scan Request Status
- Relatch Request Status
- Rod Test Request Status
- Inoperable Rod Request Status

An initialization request status flag initiates CRMS program activities required to properly initialize the RWM system. The CRMS subsystem must evaluate initial operating conditions whenever the RWM system is placed on-line (initialized). This initialization request is set by the DAS subsystem when the DAS first begins operation and is used to trigger initial CRMS subsystem operation.

The full core scan request status flag is used by CRMS to detect the performance of scanning activity by the DAS subsystem. This status flag allows CRMS to determine the occurrence of a full core scan regardless of the source of the scan request. CRMS rod position monitoring in the scan mode is triggered by this status flag.

The relatch request status flag is used to request a "relatch" by CRMS to the control rod sequence. A relatch is simply an evaluation of the proper sequence step corresponding to present rod positions. This function is necessary for CRMS to establish the present sequence step during sequence monitoring activities. The relatch request status flag may be set by numerous CRMS subsystem modules or by other RWM software subsystems.

The remaining system status flags are used to request special sequence monitoring activities by CRMS. These request flags are only of importance to CRMs subsystem operation during the performance of sequence monitoring activities.

Upon receipt of a rod test request, CRMS attempts to initiate the RWM system "rod test" mode. This mode of RWM system operation may only be entered if all control rods are fully inserted within the reactor core. Once entered, CRMS will allow the operator to select and withdraw any single control rod regardless of the sequence loaded on the RWM. This allows the operator to fully utilize the one-rod-out permissive function during reactor shutdown conditions without requiring bypass of the RWM system.

Upon receipt of an inoperable rod request by CRMS, the operable status of control rods can be changed for sequence monitoring logic. Inoperable control rods must be removed from the normal sequencing requirements for power operation (ie, Banked Position Withdrawal Sequence). This status flag triggers changes in the status of control rod operability as managed by the CRMS subsystem.

3.2.4 Control Rod Sequencing Constraints

3.2.4.1 General

Any of six seperate sequences may be loaded on the RWM system including special test and shutdown margin sequences as well as the standard operating sequences for power operation (A1,A2,B1 or B2). The control rod sequence is detailed through an engineer defined sequence (EDS) developed using the off-line sequence editor subsystem. Whenever the A or B sequences are loaded at the RWM system, CRMS additionally checks for conformance to Banked Position Withdrawal Sequence (BPWS) rules.

3.2.4.2 Engineer Defined Sequence (EDS)

The engineer defined sequence consists of a stepwise listing of control rod withdrawals. Each step identifies a control rod or group of rods to be withdrawn and the applicable limits for control rod motion. These limits for rod motion are the defined step insert and withdraw limits which establish bounds for rod motion during a sequence step.

The control rod sequence identified through the engineer defined sequence always begins from an all-rods-in condition. The series of steps in the engineer defined sequence establishes a contiguous sequence for the movement of control rods to a target control rod pattern.

Test or shutdown margin sequences are always provided as a stepwise withdrawal sequence of individual control rods. This ensures that the exact sequence for rod movement is maintained under test or shutdown margin conditions.

In contrast, the standard control rod sequences developed for normal power operation are generally provided as a stepwise withdrawal sequence for groups of control rods. The rod grouping utilized in these sequences is generally based on BPWS rod group definitions since these sequences are required to be consistent with BPWS requirements. Each step identifies appropriate insert and withdrawal limits for a defined BPWS group or engineer defined BPWS subgroup.

3.2.4.3 Banked Position Withdrawal Sequence (BPWS)

The Banked Position Withdrawal Sequence consists of a series of rules for the banked motion of control rods within the core (Reference NEDO 21231). The banked withdrawal sequence of control rod groups identified through these rules reduces control rod worths to a level consistent with analyzed reactor safety limits.

The rules establish sequencing constraints for a defined set of ten (10) rod groups within the reactor core. Seperate rules apply for control rod movement both above and below 50 percent control rod density. Below 50 percent control rod density, rod motion is constrained by sequencing requirements for defined BPWS groups 1 through 4. Above 50 percent rod density, rod motion is constrained by sequencing requirements for the remaining control rods defined in BPWS groups 5 through 10.

Normal power operating sequences identified in the engineer defined sequences are checked for BPWS consistency through a user specified sequence step by the sequence editor subsystem. However, the CRMS subsystem also checks to ensure that BPWS sequencing requirements are met when these sequences are loaded on the RWM system. This on-line BPWS checking by CRMS ensures adherence to BPWS rules during normal power operation.

3.2.5 Sequence Monitoring Operations

3.2.5.1 General

Under proper system input conditions described above, the CRMS subsystem directs the sequence monitoring function of the RWM system. The CRMS subsystem monitors the motion of control rods against the desired sequence loaded on the RWM system. Error conditions involving the insertion or withdrawal of control rods are identified by CRMS as they occur and the status of control rod blocks is controlled in computer memory.

During active sequence monitoring operation, the CRMS subsystem must "latch" to the proper sequence step. This process requires the evaluation of present rod positions in comparison to the desired rod sequence. The CRMS subsystem determines the current location within the sequence and existing sequence errors through this process.

Once the proper sequence step is established, the CRMS subsystem controls the status of rod blocks maintained in computer memory to direct the enforcement of the desired rod sequence. Whenever any change is detected in control rod positions which exceeds the bounds established for the sequence (2 insert errors or 1 withdraw error), corresponding control rod motion is blocked except for the correction of existing error conditions. As a result, an insert block condition will occur if more than two rod insert errors are determined to exist and a withdraw block condition will occur with a single withdraw error. The CRMS subsystem provides appropriate messages concerning all existing error and block conditions for the other RWM subsystems.

3.2.5.2 Sequence Latching Logic

Sequence latching activity is performed by the CRMS subsystem in conjunction with the update of control rod position data during both the scan mode and operator follow mode. Following the performance of a full core scan by the RWM system, a relatch to the sequence is performed taking into account the current positions of all rods in the core. During updates of rod position in the operator follow mode, the CRMS subsystem performs in-step latching activity. In-step latching involves the increase or decrease of the latched sequence step based on the selection and/or movement of control rods by the operator.

A relatch to the sequence is generally performed whenever the proper sequence step is unknown or requires reevaluation due to changing plant conditions. Instances in which a relatch is performed by CRMS include the following circumstances:

- o RWM system initialization
- o RWM system unbypass
- o Following any full core scan (power below LPSP)
- o Following correction of an existing insert or withdraw error condition
- o Following rod drift timer expiration (rod drift reset)
- o Following operator request
- o When power drops below LPAP
- o When power drops below LPSP
- o On a timed interval during operation in the Transition Zone (Power between LPSP and LPAP)

During a relatch, the CRMS subsystem first attempts to determine the sequence step by a comparison of the number of control rod notches withdrawn to the notch withdrawals required by the sequence. If the sequence step can be determined in this manner without the identification of rod insert or withdrawal errors, the relatching process is complete. Otherwise, the proper sequence step is determined through a more detailed search of the rod sequence.

When rod insert or withdrawal errors are determined to exist, the CRMS subsystem searches to establish the highest completed sequence step such that less than three insert errors exist and at least one rod in step is withdrawn past the step insert limit. This effectively results in a relatch to the highest sequence step allowable without the occurrence of RWM insert block conditions.

Once a relatch to the sequence is completed, in-step latching is performed by the CRMS subsystem to maintain the proper sequence step during rod motion by the operator.

An increase in the latched sequence step is possible if attempted rod movement by the operator will result in less than three existing insert errors. This effectively allows a step increase by the RWM system only if it can be achieved without the occurrence of an insert block condition.

A decrease in the latched sequence step is possible only if all control rods in the present step have been moved to the associated step insert limit. This effectively allows a step decrease by the RWM system only if it can be achieved without the occurrence of a rod withdraw block condition.

3.2.5.3 Sequence Error and Rod Block Logic

Sequence error and rod block conditions are determined by the CRMS subsystem using a defined set of sequence monitoring logic. The logic used by the CRMS subsystem establishes absolute definitions of sequence error and block conditions as detailed below.

The three error conditions identified through sequence monitoring activity consist of control rod selection, insert and withdrawal errors. Precise definitions for each of these error conditions are provided in Appendix 1 of this manual but are repeated here for further clarification.

A select error exists whenever the control rod selected by the operator is determined to be outside of the currently loaded sequence (allowable latched step). The CRMS subsystem evalutes rod selection by the operator to ensure that the rod selected for motion meets either of two conditions. The control rod must either be within the current latched step or be within the next highest or next lowest step allowable through in-step latching requirements. Otherwise a rod selection error exists.

Rod insertion errors exist whenever a control rod is inserted to a position less than the insert limit for the last sequence step in which the control rod was defined. Insert errors can therefore be produced for rods positioned in the present sequence step or any previously completed sequence step.

Rod withdrawal errors exist whenever a control rod is withdrawn to a position beyond the last step in which the control rod was defined. If the control rod was not defined within the sequence up through the latched step, the rod must remain fully inserted or be defined as a withdraw error. A rod withdrawal error can therefore be produced for any control rod in the core with the exception of any fully withdrawn in-sequence rods.

The rod block logic employed by the CRMS subsystem is based upon the number of insert and/or withdraw errors which exist as defined above. As described earlier, when error conditions exist which exceed the bounds established for the sequence (2 insert errors or 1 withdrawal error), rod blocks are initiated by CRMS. Only corrective motion of control rods is allowed to clear existing errors under these circumstances.

Specific rod sequence conditions which cause a rod insert block during conditions requiring sequence enforcement may be summarized as follows:

- There is an existing rod withdrawal error resulting in a rod withdrawal block condition and the operator is not attempting its correction (operator has selected a rod differing from the withdraw error rod).
- Three insert errors have been produced by the operator during control rod motion.

Specific rod sequence conditions which cause a rod withdraw block during conditions requiring sequence enforcement may be summarized as follows:

- There are three existing rod insert errors resulting in a rod insert block condition and the operator is not attempting their correction (operator has selected a rod differing from any of the three insert error rods).
- A withdraw error has been produced by the operator during control rod motion.
- One or more rod withdrawal errors are determined to exist upon system initialization, system unbypass or power reduction below the LPSP.

3. Other Indications

   - Red scram light lit on the full core display for the affected rod.
   - Control rod position indicates blank with green backlighting on full core display.
   - One divisional group of scram solenoid lights <u>**not**</u> lit on Panels 4F **and** 6R or 7R.
   - Accumulator LOW PRESS/HI LEVEL alarm on 5F/6F.

3.1.2 **If** one control rod is moving in,

then **PERFORM** the following:

1. **SELECT** the rod and **APPLY** a continuous insert signal to position 00. [ ]
2. **ISOLATE** the associated HCU in accordance with Procedure 302.1, Control Rod Drive Hydraulic System. [ ]
3. **MONITOR** the following parameters for indications of fuel failure:
   - Off-gas activity [ ]
   - Reactor coolant activity [ ]
   - Main steam line radiation [ ]
4. **NOTIFY** Reactor Engineering of the abnormal rod motion. [ ]
5. **CONSULT** Technical Specifications, Section 3.2 [ ]

Group Heading **CONTROL RODS/DRIVES ROD CNTRL**		**H-6-a**
ROD DRIFT		
CAUSES: Any of the Control Rods drifting more than 3" through an odd rod position, when the Control Rod is not selected.	SETPOINTS: Actuation of odd numbered position switch on non-selected control rod.	ACTUATING DEVICES: AR2-1, AR2-2, AR2-3, AR2-4 Reference Drawings: GE 148F481 GU 3E-611-17-010

CONFIRMATORY ACTIONS:

Check Control Rod position indication on Panel 4F.

AUTOMATIC ACTIONS:

NONE

MANUAL CORRECTIVE ACTIONS:

If <u>more than one</u> Control Rod is moving in or out abnormally, scram the reactor in accordance with 2000-ABN-3200.01, Reactor Scram. If single rod unintended motion is indicated (insert or withdrawal), perform the actions defined in 2000-ABN-3200.06, Abnormal Control Rod Motion, as appropriate.

Question 47

Regarding the IRM/APRM circuitry and indications, the following sources of power exist:

- ±24 VDC, which powers the detector circuitry. This power is via batteries.
- CIP-3, which provides recorder power on Panel 4F.
- RPS bus 1 and 2, which powers trip circuitry and RPS trip units associated with the respective drawers.

For ±24 VDC, this power is provided by batteries, which will NOT be affected by the stated transient.

For CIP-3, it's normal power source is via the rotary inverter powered from VMCC 1B2. On a loss of VMCC 1B2 (from the LOOP), the rotary inverter will automatically swap to the DC motor, powered from DC Distribution Center B, with no loss of AC output voltage from the rotary inverter, and no loss of power to CIP-3.

For RPS buses 1 and 2, the RPS MG set flywheels will maintain power long enough for the EDGs to start and re-power 1C and 1D buses. The basis for this is presented below.

In a memo dated January 11, 1996 regarding loss of RPS power during LOOP, the RPS engineer provided the following information. (Copy of memo is enclosed)

- Upon a loss of offsite power with a successful anticipatory scram, the RPS MG set output breaker and Electrical Protection Assemblies will trip on under-frequency or under-voltage in approximately 15 seconds.
- Upon a loss of offsite power with no anticipatory scram, the RPS MG set output breaker and EPAs will trip on under-frequency or under-voltage in approximately 4 seconds.

The difference in the response of the RPS MG set output upon a loss of supply voltage described above depends on whether the anticipatory scram signal (turbine trip on LOOP) is received or not. This is the result of the difference in RPS load pre-scram versus post-scram. After a scram, the RPS load is greatly reduced due to the de-energization of the scram pilot solenoid valves, the scram contactors, and the condenser low vacuum or turbine trip control relays.

Since no power is lost to the IRM and APRM circuits, all indications will be available at Panels 4F, 3R, and 5R throughout the transient.

During the initial license class simulator training, the students were exposed to numerous losses of offsite power scenarios. During all scenarios where the EDGs were available, RPS power was NOT lost because the EDGs re-power the 1C and 1D buses within approximately 10 seconds from the loss of power signal. Since the RPS MG sets are designed to maintain voltage and frequency for approximately 15 seconds, this results in NO loss of RPS power during the transient.

Based upon this information, answers "b" and "d" are correct.

References: RAP 9XF-5-c, CIP-3 INV AC INP LOST
GPUN Memo 2252-96-001, dated January 11, 1996

QUESTION #47

Given the following conditions:

- Immediately following a loss of all offsite power you are the reactor operator and observe one control rod at position 48 with the remaining control rods at 00.
- Ten seconds later both emergency buses are energized from Diesel Generators (EDGs).

Which of the following describes the affect on IRM/APRM indications?

A. Lose IRM/APRM indications due to loss of PSP-1&2.

B. Maintain IRM/APRM indications due to DC power supply available.

C. Lose IRM/APRM indication due to loss of vital buses and RPS MG set voltage.

D. Maintain IRM/APRM indications due to re-powered busses and RPS MG set flywheels.

Answer: B
EXPLANATION: *DC will maintain power via an inverter. All remining power sources will (at least momentarily) lose power or do not power up the IRM/APRM indicators.*

TECHNICAL REFERENCE(S): Neutron Monitoring Lesson Plan
(Attach if not previously provided)

Proposed references to be provided to applicants during examination: ______

Learning Objective: ______ (As available)

Examination Outline Cross-reference:

Level	RO	SRO
Tier #	2	___
Group #	1	___
K/A #	215005/K6.01	
Importance Rating	3.7	___

K/A Topic Description:
Knowledge of the effect that a loss or malfunction of the RPS will have on the APRM/LPRM

Question Source: Bank # ______
Modified Bank # ______ (Note changes or attached parent)
New X

Question Cognitive Level: Memory or Fundamental Knowledge ______
Comprehensive or Analysis X

10 CFR Part 55 Content: 55.41 X
55.43 ______

Comments: Information on recorder power obtained from OC training.

Group Heading

V I T A L   P O W E R   A C   X F E R S

9 X F - 5 - c

C I P - 3   I N V
A C   I N P   L O S T

CAUSES:	SETPOINTS:	ACTUATING DEVICES:
DC drive motor for continuous instrument panel supply generator running. This indicates loss of power or trip of the AC power.	DC Drive motor running	2MS Reference Drawings: BR 3013, Sh. 1 GE 3300C15A3164 GU 3E-611-17-022

CONFIRMATORY ACTIONS:

DC Drive light is "ON" at CIP-3 Rotary Inverter Control Panel.

AUTOMATIC ACTIONS:

Inverter switches to DC drive.

Once in DC-RUN, the rotary Inverter will transfer back to AC DRIVE, after a 2 minute time delay, when the start selector switch is placed in the AUTO RUN position.

MANUAL CORRECTIVE ACTIONS:

Correct cause as necessary and return AC motor to service.

Reference Procedure 339, "Vital Power System".

GPU Nuclear **Memorandum**

Subject: Loss of RPS Power During LOOP

Date: January 11, 1996

From: J. P. Munley, RPS Engineer

Location: Oyster Creek 2252-96-001

To: J. Vaccaro, Instructor Nuclear IV

Per our discussions, the following provides a description of RPS MG Set flywheel design and operation and will serve as input in modeling the Simulator for a loss of offsite power.

The RPS Motor Generator Set flywheel is designed to mitigate a 2 second supply voltage interruption with a drop of output voltage and frequency of less than 5% and recovery to steady state regulation after restoration of rated supply voltage within 2 seconds. Experience has shown that the output voltage and frequency drop following a loss of MG Set supply power is load dependant. For higher loads, the output voltage and frequency degrade more quickly than for lower loads, when the output voltage and frequency degrade more slowly.

The RPS will, therefore, trip at different times upon a loss of supply power depending upon the load on the MG Set.

1. Upon a loss of offsite power with a successful anticipatory scram, the RPS MG Set output breaker and Electrical Protection Assemblies will trip on under-frequency or under-voltage in approximately 15 seconds.

2. Upon a loss of offsite power with no anticipatory scram, the RPS MG Set output breaker and electrical protection assemblies will trip on under-frequency or under-voltage in approximately 4 seconds.

The difference in the response of the RPS MG Set output upon a loss of supply voltage described above depends on whether the anticipatory scram signal is received or not. This is the result of the difference in RPS load pre-scram versus post-scram. After a scram, the RPS load is greatly reduced due to the de-energization of the scram pilot solenoid valves, the scram contactors, and the Condenser Low Vacuum or Turbine Trip control relays.

This description provides the necessary details of RPS MG Set output design and operation during a loss of offsite power to allow approximate modeling of the OC Simulator. Please contact me with any further questions or comments.

J. P. Munley
Extension 4252

/bl

cc: C. Desai, System Engineer
P. Cervenka, Plant Engineering Supervisor

Question 71

The turbine bypass valves do NOT pass approximately 10% steam flow. Each bypass valve passes approximately 5% steam flow, while the FLOW MISMATCH alarm is set at 7%. Based upon this, there are two possible answers to this question, based upon two failure mechanisms which affect the bypass valves.

The first failure mechanism deals with a failure of the Bypass relay in the turbine front standard, calling for turbine bypass valves to open. The Bypass relay in the Front Standard translates relay (servo) motion into a mechanical motion which exits the Front Standard, goes through the floor to the Heater Bay and across the Heater Bay ceiling to the individual bypass valves contained in two valve blocks. The mechanical motion at the bypass valve blocks is transmitted to each of the nine bypass valves through a cam and cam follower arrangement. As the cam rotates, the lobe on the first bypass valve will progressively open #1 bypass valve throughout its range of travel from full shut to full open. When the first bypass valve reaches approximately 70% open, the cam for the second bypass valve will progressively open #2 bypass valve. When the second bypass valve is approximately 70% open, the cam for the third bypass valve will progressively open #3 bypass valve. Since all nine bypass valves are controlled by this cam arrangement, each successive bypass valve will start to open before the previous valve is fully open. In the case of the Bypass relay fault, a second bypass valve will be partially open when the first bypass valve is fully open. This steam flow will more than likely exceed 7%, resulting in the Flow Mismatch alarm. Additionally, the flow being diverted from the HP turbine through the now-open bypass valves will cause turbine third stage extraction pressure to drop. Since the RPS system uses third stage extraction pressure to bypass the anticipatory scrams, any reduction below the equivalent 40% pressure will cause the anticipatory scrams to in fact be bypassed, even though actual reactor power can be above 40%. In this case, answer "d" is a correct answer.

The second failure mechanism that can affect turbine bypass valves is a failure of an individual bypass valve. Each of the nine bypass valve mechanisms at the two bypass valve blocks in the heater bay have a fast-acting accumulator to ensure the bypass valve will respond quickly when needed. These accumulators are 12 inches in diameter and use turbine operating oil pressure (at approximately 250 psig) as their hydraulic motive force. If an individual bypass valve accumulator were to fail in the open direction, <u>ONLY</u> that bypass valve will be affected. Therefore, it will result in an approximate 5% steam flow diversion from the main turbine through the open bypass valve. This 5% steam flow will <u>NOT</u> be sufficient to activate the Flow Mismatch alarm. In this case, if the alarm were to come in, it can only be caused by additional steam flow to reach the 7% alarm setpoint, and it can be deduced there is a steam leak somewhere in the Turbine Building. Therefore, answer "a" is correct for this failure mechanism.

Based upon the given information and these possible failure mechanisms, answers “a” and “d” are correct.

References: RAP J-7-a, FLOW MISMATCH
GE 233R309, Turbine Controls
OCNGS UFSAR, Section 10.2.1, Turbine Generator, pg. 10.2-1

QUESTION #71

The following plant conditions exist:
- The reactor power has just been increased to 40% power
- Turbine-Generator is on the line at approximately 200 MWE
- A malfunction causes a bypass valve to fully open
- FLOW MISMATCH alarm (J-7-a) annunciates shortly after the bypass valve (BPV) opens

Answer the following:
a) Is FLOW MISMATCH an expected alarm for the stated conditions?
b) What is the operational significance of this alarm at 40% power?

A. **NO** this is **NOT** expected. The significance is that a steam line break has occurred in the Turbine Building.

B. **NO** this is **NOT** expected. The significance is that extraction steam has isolated from feedwater heaters.

C. Yes this is expected. The significance is that extraction steam has isolated from feedwater heaters.

D. Yes this is expected. The significance is that Turbine Anticipatory Scrams have been bypassed.

ANSWER: D

EXPLANATION:
This is an expected alarm since BPVs will "pass" approximately 10% steam flow. The alarm is set at 7%. The steam going through the BPVs bypass first stage turbine and will not be "counted" as power for the 40% trip setpoint. With no other alarms in it should not be assumed that there may be a steam line break. Although the BPVs will have some impact on extraction steam flow it is not the reason the alarm is actuated.

TECHNICAL REFERENCE(S): Alarm Response J-7-a "FLOW MISMATCH" (Attach if not previously provided)

Proposed references to be provided to applicants during examination: None

Learning Objective: ____________ (As available)

Examination Outline Cross-reference:

	RO	SRO
Level		
Tier #	2	
Group #	2	
K/A #	239001/A1.09	
Importance Rating	3.5	

K/A Topic Description:
Ability to predict and/or monitor changes in parameters associated with the Main and Reheat Steam System controls including the Main Steam Flow.

Question Cognitive Level:	Memory or Fundamental Knowledge	____
	Comprehensive or Analysis	X
10 CFR Part 55 Content:	55.41 X	
	55.43 ____	

Comments: Licensee should confirm the stated conditions would prompt an RO to initiate a shutdown without specific direction from the Shift Manager.

FLOW MISMATCH

CAUSES:	SETPOINTS:	ACTUATING DEVICES:
Greater than 7% difference in the total main steam flow and the sum of steam flow through the turbine 1st stage and extraction steam flow to the 2nd stage reheater.	7% with 10 second time delay	DRFCS Software DO-5505 Tag: STM_LEAK_ALM Hardware DIO-2 DO#8 Reference Drawings: GU 3E-625-41-001, Sht. 3 GU 3E-611-17-011

CONFIRMATORY ACTIONS:

1. Check turbine bypass valve status.
2. Check Condenser Bay and Trunnion Room radiation level and temperatures for indications of a possible steam line break.

AUTOMATIC ACTIONS:

None

MANUAL CORRECTIVE ACTIONS:

If the Plant is operated with Bypass valves open and the Main Turbine is on-line, then inappropriate bypassing of the Turbine Anticipatory Scrams may occur.

IF a steam line break is confirmed,

THEN scram the reactor in accordance with 2000-ABN-3200.01, Reactor Scram.

This alarm indicates that a parameter has exceeded or has the potential to exceed an Emergency Action Level (EAL). Enter Procedure EPIP-OC-.01, Classification of Emergency Conditions. EAL - RCS Integrity.

10.2 TURBINE GENERATOR

10.2.1 Design Bases

The Turbine Generator has been designed to produce electrical power from the steam generated in the reactor, and to discharge exhaust steam into the condenser.

The turbine nameplate rating is 640,700 kW, 1800 rpm, 15 stage, tandem compound, six flow, two stage (513°F) reheat steam turbine with 38 inch last stage buckets, designed for steam conditions of 950 psig saturated with 0.28 percent moisture, 1 inch mercury absolute exhaust pressure and 0 percent makeup while extracting for three stages of feedwater heating. The six flow design and speed of 1800 rpm were dictated by the pressure and temperature of the steam available from the reactor.

The generator is a direct driven, 60 cycle, 24,000 volt, 1800 rpm conductor cooled, synchronous generator rated at 687,500 kVA at 0.8 power factor, 45 psi hydrogen pressure and 0.58 Short Circuit Ratio (SCR). The turbine includes one double flow (high pressure) and three double flow (low pressure) elements. Exhaust steam from the high pressure element passes through moisture separators and reheaters before entering the three low pressure units. The separators are designed to reduce the moisture content of the steam to less than 1 percent by weight.

The turbine controls include speed governor, overspeed governor, steam control valves, main stop and bypass valves, combined intercept and reheat stop valves, and two initial pressure regulators: one electro hydraulic and the other mechanical.

The ability of the plant to follow system load is accomplished by adjusting the reactor power level, either by regulating the reactor recirculation flow or by moving the control rods. The turbine speed governor can override the initial pressure regulation, and close the steam admission valves when an increase in system frequency or a loss of generator load causes the speed of the turbine to increase. In the event that the reactor is delivering more steam than the admission valves will pass, the excess steam is bypassed directly to the Main Condenser by automatic pressure controlled bypass valves. Other standard protective devices are included.

Control and bypass valves are provided to maintain constant reactor pressure. The Turbine Bypass System (TBS), with a rated capacity of 40 percent of the turbine rated steam flow is used during startup to control reactor pressure until the turbine can use all of the reactor steam. The system also limits transient pressure changes and resultant reactor flux

Question SRO 3

In the Containment Pressure leg of Primary Containment Control, if primary containment isolation is NOT required (i.e., pressure is less than 3 psig), direction is given to vent the containment in order to maintain containment pressure below 3 psig. There is absolutely NO direction implicit or explicit to secure the venting if it will result in dropping below the CSIL.

Answers "c" and "d" CANNOT be correct, as it states venting is NOT allowed. This would be in direct conflict with the directions to vent the containment and maintain pressure below 3 psig.

Answers "a" and "b" are both correct.

In answer "a", directions to vent the containment per the steps in the Pressure Control leg do take precedence over any directions to spray in the Drywell Temperature leg. By procedure, we are required to vent the containment to keep it less than 3 psig.

In answer "b", venting the containment will result in a reduction of temperature. This is a classic Ideal Gas Law concept. Since the containment volume is constant, any reduction in pressure will result in a corresponding reduction in temperature. This is expressed below.

$$P_1V_1/T_1 = P_2V_2/T_2$$

This concept is part of the Generic Fundamentals course the candidates went through While the drywell temperature reduction may not be significant, it will occur.

Additionally, the class has been taught that a total loss of drywell cooling will take approximately 13 hours for drywell temperature to reach 281 °F. This is based upon engineering calculations performed in the 1980s that confirms this. The annunciator response for drywell temperature above 150 °F and not able to be reduced, is to perform a normal reactor shutdown. The reactor can be shutdown and cooled down to a cold shutdown condition within this time frame. Therefore, spraying the containment for a total loss of drywell cooling is not needed, nor desired.

While the basis for answer "a" is directly related to the EOPs, the basis for answer "b" is a fundamental concept, which is reinforced during all phases of training. The question did NOT distinguish between a procedurally driven concept or a fundamental concept. Therefore, answers "a" and "b" are correct.

References: EMG-3200.02, Primary Containment Control
EOP User's Guide, pp. 2-28 and 2-29
BWR Generic Fundamentals, Thermodynamics, Chapter 3, Steam
DOE Fundamentals Handbook, Thermodynamics, Heat Transfer, and Fluid Flow

QUESTION # SRO-3

A loss of all drywell cooling has occurred and you have entered Primary Containment Control, EMG-3200.02 when the drywell temperature entry conditions are exceeded.

The following conditions exist:

- All attempts to restore drywell cooling have failed.
- Drywell pressure is at 2.75 psig and steady.
- When you direct the RO to "vent the containment per support procedure 31" the STA notifies you that the drywell temperature is approaching 200 degrees F.
- **NO** other entry conditions for Primary Containment Control or RPV control exist at this point.

Answer the following:
Are you allowed to vent the containment? Also, provide a basis for this action.

A. Yes, reduction of drywell pressure is the most important strategy at this point.

B. Yes, venting the drywell will also result in reduction in drywell temperature.

C. No, venting the drywell will result in exceeding the Containment Spray Initiation Limit.

D. No, venting the drywell may cause a inadequate NPSH for the Containment Spray Pumps.

ANSWER: C

EXPLANATION:
With drywell temperature above 200 degrees F any reduction in drywell pressure (below 2.75 psig) will result in exceeding CSIL. Once CSIL is exceeded the plant will, ultimately require EMERGENCY DEPRESSURIZATION since sprays cannot be initiated. The order should be changed to "spray the containment" before CSIL is exceeded. With no other entry conditions present, NPSH should not be a problem for Containment Spray Pumps.

TECHNICAL REFERENCE(S): EOPs (Attach if not previously provided)

Proposed references to be provided to applicants during examination: EOPs

Learning Objective: ________ (As available)

Examination Outline Cross-reference:

Level	RO	SRO
Tier #	___	1
Group #	___	1
K/A #	295024/EA2.02	
Importance Rating	___	4.0

K/A Topic Description:
Ability to determine and/or interpret drywell temperature as it applies to High Drywell Pressure.

Question Source: Bank # ___
Modified Bank # ___ (Note changes or attached parent)
New X

Question Cognitive Level: Memory or Fundamental Knowledge X

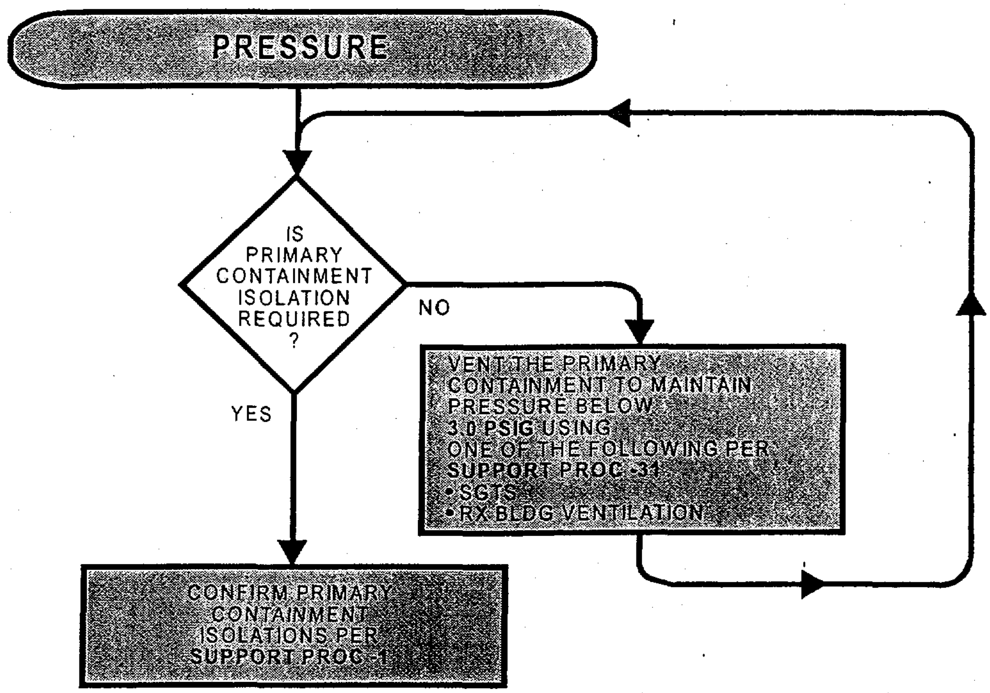
Comprehensive or Analysis

10 CFR Part 55 Content: 55.41 X

55.43 55.43(b)(5)

Comments: Applicant must select the appropriate "flow path" in Containment Control. With a LOCA, drywell pressure will increase with temperature, however in the loss of drywell cooling with no LOCA temperature increase will be greater than pressure increase, hense venting the containment is NOT the right thing to do.

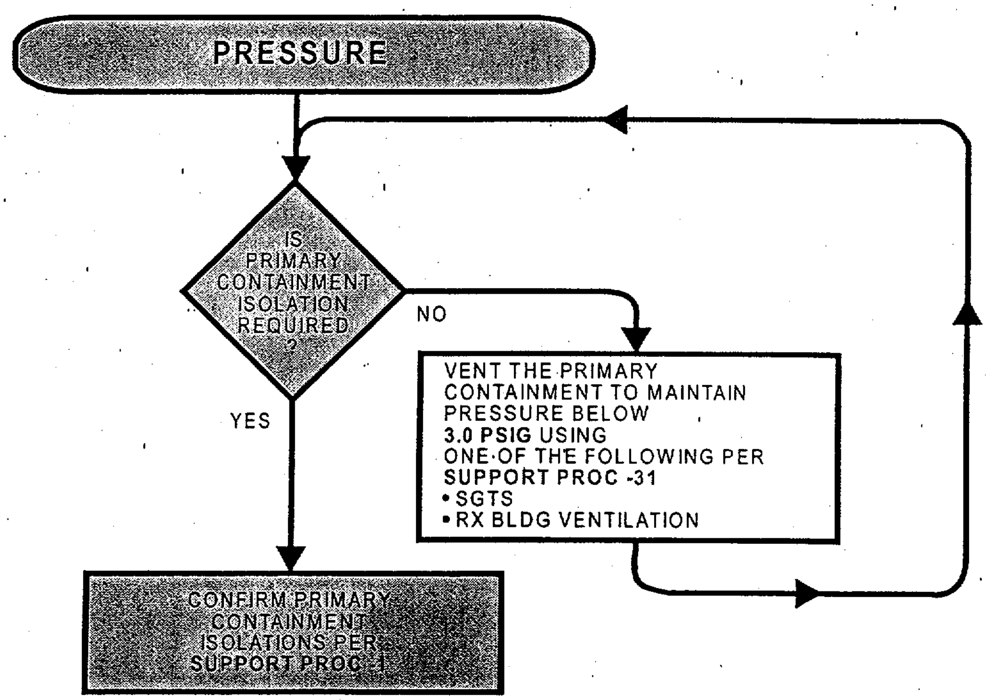
PRIMARY CONTAINMENT PRESSURE CONTROL



DISCUSSION

This question is asked to determine if a Reactor Lo-Lo water level (86 in.) OR high Drywell pressure (3.0 psig) signal is present. If neither signal is present, the operator is permitted to use SBGT or Reactor Building Ventilation to vent the Primary Containment via the 2 in. vent lines as necessary to maintain Drywell pressure below 3 psig. If an isolation signal is present, the operator is directed to abandon containment venting in accordance with Support Procedure -31 and confirm Primary Containment isolations in accordance with Support Procedure -1.

PRIMARY CONTAINMENT PRESSURE CONTROL



DISCUSSION

The initial action taken to control Primary Containment pressure employs the same methods used during normal Plant operations: using 2 in. containment vent lines to SGTS or Reactor Building Ventilation as required to maintain containment pressure below the high Drywell pressure scram setpoint. Thus the Primary Containment Pressure Control leg provides a smooth transition from normal system operating procedures to emergency operating procedures, and assures that normal methods of Primary Containment pressure control are attempted in advance of initiating more complex actions to terminate increasing Primary Containment pressure.

Support Procedure -31 provides instructions for venting the Primary Containment via the 2 in. vents to either the SGTS train or the Reactor Building Ventilation system. The choice of systems is left to LOS discretion. The 2 in. Torus vents are the preferred vent path because they take advantage of the Torus scrubbing which will help remove Drywell airborne radionuclides as they flow down the downcomers and bubble through the Torus water volume before exiting the 2 in. Torus vent line.

If the Torus cannot be vented because of high Torus level or mechanical failure of the 2 in. Torus vent valves, Support Procedure -31 provides contingency actions for venting the Drywell through the Drywell 2 in. vent lines.

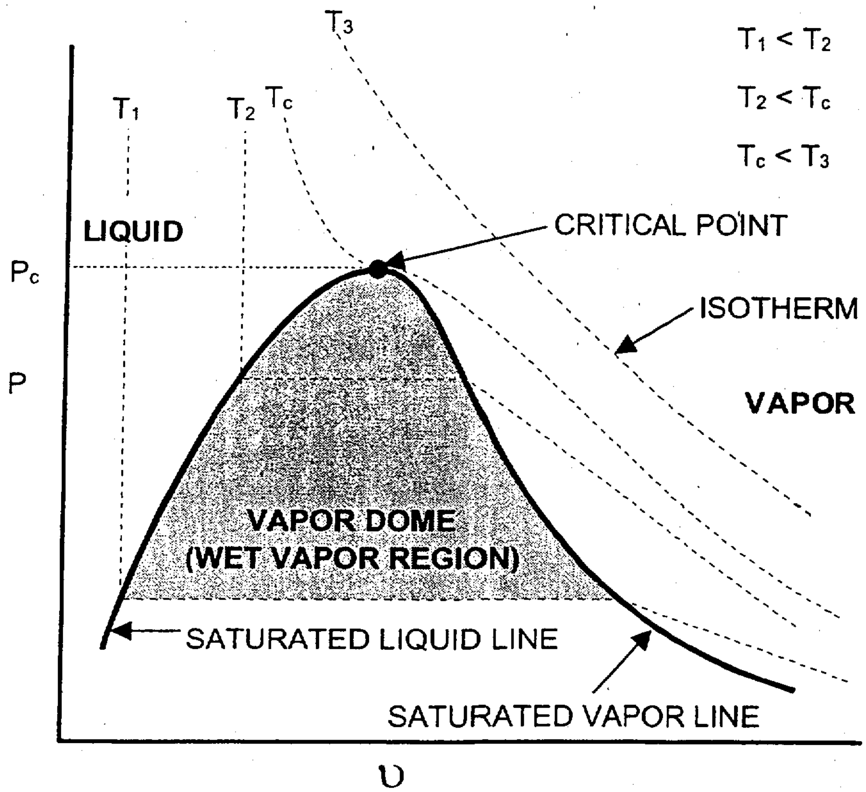
No direction is given to the operator at this time to override isolation interlocks or to exceed normal offsite release rates. If Primary Containment pressure cannot be controlled below 3.0 psig or if RPV level drops below 86 in., a containment isolation will occur and venting will be terminated. If higher than normal offsite release rates are experienced while venting, the operator should secure the vent path.

It should be noted that use of Support Procedure -31 is only required as necessary to maintain Primary Containment pressure below 3.0 psig. If upon entry to the PRIMARY CONTAINMENT CONTROL procedure, Primary Containment pressures are at their normal values and not increasing, venting per Support Procedure -31 is not required.

BWR GENERIC FUNDAMENTALS

THERMODYNAMICS

CHAPTER 3
STEAM



STUDENT TEXT

REV 3

Using the element's atomic weight improves the accuracy of the calculation. However, the added accuracy is insignificant and is not usually required. Hence, the following relationship can be made:

$$\text{Number of moles} = \frac{\text{Mass (grams)}}{\text{Atomic Mass}\left(\frac{\text{grams}}{\text{mole}}\right)}$$

Equation 3-2

This is true for all substances whether they be solids or fluids (liquids, vapors, or gases).

Calculate the number of moles of U-238 that are present in a fuel rod containing 3 kg of U-238.

Example 3-1

IDEAL GASES

Most familiar gases are colorless and odorless, such as the oxygen and nitrogen of the atmosphere, the bubbles of carbon dioxide that rise in a glass of soda pop, and the hydrogen or helium gas that is used to fill balloons. A few gases are colored; for example, nitrogen dioxide is red-brown and iodine vapor is violet. Anything that we can smell exists in the gaseous state, because our sense of smell reacts only to gases.

The word "gas" refers to a substance that at ordinary temperatures and pressures is present in the gaseous state only. The word "vapor" is used for gas that has evaporated from a material that is usually solid or liquid at ordinary temperatures.

Gases have observable physical properties. They fill available space, but can be compressed into a smaller volume by applying pressure. They are affected by temperature, can expand and contract, or exert different pressures. It is obvious from the force of the wind on a stormy day that gases can flow readily from place to place and that they have mass. However, gases are not very dense. An air-filled vessel floats on the surface of a pond because the air is less dense than the water.

Because of their interrelated effects, temperature, pressure, and volume must be specified when discussing gases. The quantitative relationships among the temperature, pressure, and volume of a gas are expressed in the gas laws, which were first explored in the eighteenth and nineteenth centuries. Any gas that perfectly obeys the gas laws is called an ideal gas.

The properties of an ideal gas are constant throughout its mass. Chemical reactions, external forces, or molecular forces do not effect ideal gas molecules.

The Ideal Gas Law is useful because at low pressures, all real gases behave like an ideal gas. Monatomic gas behavior is similar to perfect gases. It can be described very accurately using the Ideal Gas Law, such as helium (He) and argon (Ar). Accuracy will decrease with diatomic and polyatomic gases, such as oxygen (O_2) and carbon dioxide (CO_2). Also, as gas pressure increases, the accuracy decreases. Experimentally derived corrections allow the Ideal Gas Law to be applied to the behavior of these gases with desired accuracy.

CHARLES' LAW

Figure 3-1 shows a piston and cylinder assembly filled with a gas at absolute temperature (T_1) and volume (V_1). The piston is free to move against a constant external pressure (P_1). A burner is provided to allow heat to be added to the gas.

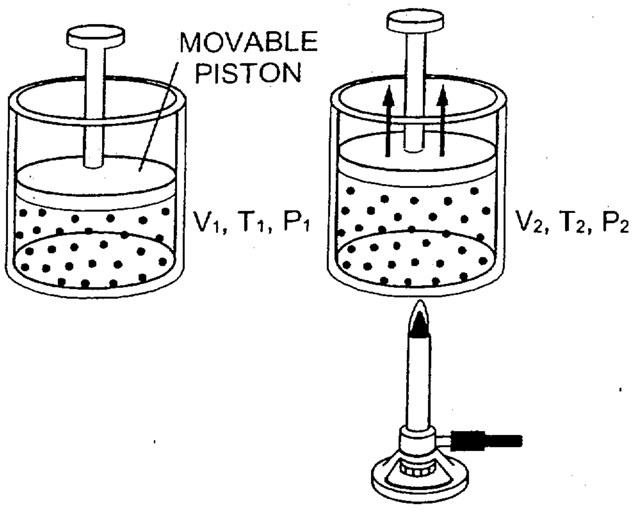


Figure 3-1 Charles' Law

Adding heat causes the temperature of the gas to increase. As the gas temperature increases, the volume increases and applies pressure against the piston causing the piston to move outward. Once the pressure on the internal piston face equalizes to the external pressure (P_1), the piston stops moving. The system is again in equilibrium. The initial pressure (P_1) is the same, but the absolute temperature (T_2) is higher and the volume (V_2) is greater.

Repeating the process of adding heat, causing the piston to move outward, and remeasuring the process variables of gas volume and temperature leads to the following conclusion:

"At low pressures, the volume of a gas at constant pressure is directly proportional to the absolute temperature of the gas."

This statement is Charles' Law, written mathematically as:

$$\frac{V_1}{T_1} = \frac{V_2}{T_2} = \frac{V}{T} = k \text{ (constant)}$$

At a constant pressure (P)

Equation 3-3

Equation 3-3 is valid only for absolute temperature measurements of low-pressure gases; the constant (k) is different for each gas.

BOYLE'S LAW

The piston and cylinder assembly is reconfigured by removing the burner. The cylinder is filled with a gas at volume (V_1), temperature (T_1), and at an absolute pressure (P_1). Heat will not be added to the gas through the cylinder, so the temperature of the gas will remain constant.

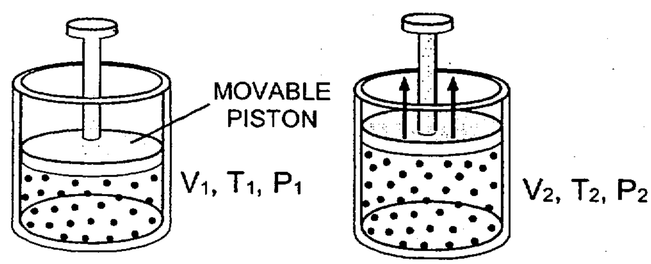


Figure 3-2 Boyle's Law

The piston is physically moved to a new position, creating a new volume (V_2) and absolute pressure (P_2). After V_2 and P_2 are measured, the procedure is repeated, recording the data. Examining the measured variables, the following conclusion about the gas may be derived:

"At low pressures, the volume of a gas at constant temperature is inversely proportional to the absolute pressure of the gas."

This statement is Boyle's Law, written mathematically as:

$$P_1V_1 = P_2V_2 = PV = k \text{ (constant)}$$

At a constant temperature (T)

Equation 3-4

Equation 3-4 is valid only for <u>absolute pressure</u> measurements; the constant (k) is different for each gas. Since temperature is constant, the units of measure have no effect on the equation.

COMBINED GAS LAW

Charles' Law and Boyle's Law are valid for ideal gases and real gases in the pressure range where a real gas behaves like an ideal gas. Therefore, any real gas at low pressure will obey these laws and may be combined to derive the following law:

> "For a given mass of any gas, the product of the absolute pressure and volume occupied by the gas, divided by its absolute temperature, is a constant."

This statement is the Combined Gas Law, written mathematically as:

$$\frac{P_1V_1}{T_1} = \frac{P_2V_2}{T_2} = \frac{PV}{T}$$

Equation 3-5

A compressor discharges into an air receiver and cycles off when the pressure in the receiver reaches 160 psia. During the compression, heat is added to the air. The temperature in the receiver is 140°F. Assuming no air loads are in service, at what temperature (°F) should the compressor restart to maintain the receiver above 150 psia?

Example 3-2

IDEAL GAS LAW

By applying the gas laws already presented in this chapter, we can derive the Ideal Gas Law. Remember, Boyle worked with constant temperature; Charles worked with constant pressure. Their laws will be further expanded to form the Ideal Gas Law.

An ideal gas is defined as one in which PV/T = K (a constant) under all circumstances. PV/T = K is a specific application of the General Energy Equation. Though no such gas exists, the fact that a real gas behaves approximately like an ideal gas provides a basis for theories for the gaseous state.

Experimenters discovered the constant (K), in terms of the number of moles (n) of gas in a sample, by understanding that the molar volume of a gas at 273K (0°C) and standard pressure [1 atmosphere (atm) or 14.7 psia] is 22.4 liters.

$$\frac{PV}{T} = K$$

Where:

P	=	Pressure (1 atmosphere or 14.7 psia)
V	=	Volume (22.4 liters)
T	=	Temperature (273 K or 0°C)
K	=	Constant (in terms of number of moles

Substituting and rearranging:

$$\frac{PV}{T} = nR$$

$$R = \frac{PV}{nT}$$

$$R = \frac{(1\,\text{atm})(22.4\,\text{L})}{(n)(273\,\text{K})}$$

Where:

n	=	number of moles of gas
R	=	universal gas constant (a conversion factor)

Empirical data has shown that the value of the universal gas constant (R) is:

$$R = 0.0821\frac{\text{atm liters}}{\text{mole K}} \text{ or } 8.314\frac{\text{J}}{\text{mole K}}$$

Equation 3-6

The universal gas constant (R) is an energy equivalent for PV energy. To convert the units of the universal gas constant from atm liters (atm ℓ) to Joules (J):

$$(1\ \text{atm}\ \ell)\left(\frac{14.7\frac{\text{lb}_f}{\text{in}^2}}{1\ \text{atm}}\right)\left(\frac{61.03\ \text{in}^3}{1\ell}\right) = 897.1\ \text{in lb}_f$$

$$(897.1\ \text{in lb}_f)\left(\frac{1\ \text{ft}}{12\ \text{in}}\right) = 74.8\ \text{ft lb}_f$$

Since:

$$1\ \text{ft lb}_f = 1.35582\ \text{J}$$

Then:

$$(74.8\ \text{ft lb}_f)\left(\frac{1.35582\ \text{J}}{1\ \text{ft lb}_f}\right) = 101.4\ \text{J}$$

Thus:

$$1\ \text{atm}\ \ell = 101.4\ \text{J}$$

Equation 3-7

DOE-HDBK-1012/1-92
JUNE 1992

DOE FUNDAMENTALS HANDBOOK
THERMODYNAMICS, HEAT TRANSFER, AND FLUID FLOW
Volume 1 of 3

U.S. Department of Energy
Washington, D.C. 20585

FSC-6910

COMPRESSION PROCESSES

Compression and pressurization processes are very common in many types of industrial plants. These processes vary from being the primary function of a piece of equipment, such as an air compressor, to an incidental result of another process, such as filling a tank with water without first opening the valve.

EO 1.32	**Apply the ideal gas laws to SOLVE for the unknown pressure, temperature, or volume.**
EO 1.33	**DESCRIBE when a fluid may be considered to be incompressible.**
EO 1.34	**CALCULATE the work done in constant pressure and constant volume processes.**
EO 1.35	**DESCRIBE the effects of pressure changes on confined fluids.**
EO 1.36	**DESCRIBE the effects of temperature changes on confined fluids.**

Boyle's and Charles' Laws

The results of certain experiments with gases at relatively low pressure led Robert Boyle to formulate a well-known law. It states that:

> the pressure of a gas expanding at constant temperature varies inversely to the volume, or

$$(P_1)(V_1) = (P_2)(V_2) = (P_3)(V_3) = \text{constant.} \quad (1\text{-}40)$$

Charles, also as the result of experimentation, concluded that:

> the pressure of a gas varies directly with temperature when the volume is held constant, and the volume varies directly with temperature when the pressure is held constant, or

$$\frac{V_1}{V_2} = \frac{T_1}{T_2} \quad \text{or} \quad \frac{P_1}{P_2} = \frac{T_1}{T_2}. \quad (1\text{-}41)$$

Ideal Gas Law

By combining the results of Charles' and Boyle's experiments, the relationship

$$\frac{Pv}{T} = \text{constant} \tag{1-42}$$

may be obtained. The constant in the above equation is called the ideal gas constant and is designated by R; thus the ideal gas equation becomes

$$P\nu = RT \tag{1-43}$$

where the pressure and temperature are absolute values. The values of the ideal gas constant (R) for several of the more common gases are given in Figure 39.

Gas	Chemical Symbol	Molecular Weight	Gas Constant ft-lbf/lbm°R	Specific Heat Btu/lbm		Specific Heat Ratio
		M	R	c_p	c_v	k
Air		28.95	53.35	0.172	0.240	1.40
Carbon dioxide	CO_2	44.00	35.13	0.160	0.205	1.28
Hydrogen	H_2	2.016	766.80	2.44	3.42	1.40
Nitrogen	N_2	28.02	55.16	0.176	0.247	1.40
Oxygen	O_2	32.0	48.31	0.155	0.217	1.40
Steam	H_2O	18.016	85.81	0.36	0.46	1.28

Steam at pressures less than 1 psia behaves very nearly as a perfect gas.

Figure 39 Ideal Gas Constant Values

The individual gas constant (R) may be obtained by dividing the universal gas constant (Ro) by the molecular weight (MW) of the gas, $R = \frac{Ro}{MW}$. The units of R must always be consistent with the units of pressure, temperature, and volume used in the gas equation. No real gases follow the ideal gas law or equation completely. At temperatures near a gases boiling point, increases in pressure will cause condensation to take place and drastic decreases in volume. At very high pressures, the intermolecular forces of a gas are significant. However, most gases are in approximate agreement at pressures and temperatures above their boiling point.

The ideal gas law is utilized by engineers working with gases because it is simple to use and approximates real gas behavior. Most physical conditions of gases used by man fit the above description. Perhaps the most common use of gas behavior studied by engineers is that of the compression process using ideal gas approximations. Such a compression process may occur at constant temperature (pV = constant), constant volume, or adiabatic (no heat transfer). Whatever the process, the amount of work that results from it depends upon the process, as brought out in the discussion on the First Law of Thermodynamics. The compression process using ideal gas considerations results in work performed on the system and is essentially the area under a P-V curve. As can be seen in Figure 40, different amounts of work result from different ideal gas processes such as constant temperature and constant pressure.

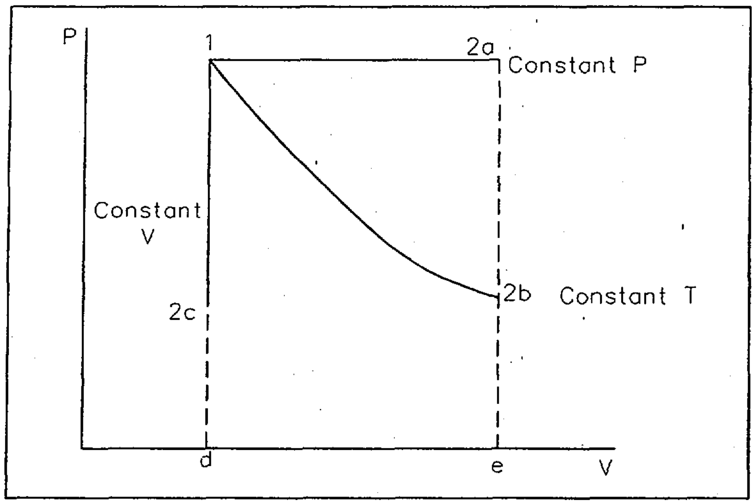


Figure 40 Pressure-Volume Diagram

Fluid

A *fluid* is any substance that conforms to the shape of its container. It may be either a liquid or a gas.

Compressibility of Fluids

Usually a fluid may be considered incompressible when the velocity of the fluid is greater than one-third of the speed of sound for the fluid, or if the fluid is a liquid. The treatment of a fluid that is considered incompressible is easy because the density is assumed to be constant, giving a simple relationship for the state of the substance. The variation of density of the fluid with changes in pressure is the primary factor considered in deciding whether a fluid is incompressible.

Question SRO 7

Answer "d" is NOT correct. The "C" Battery is declared inoperable whenever battery temperature drops below 50 °F. This is determined by battery electrolyte temperature, not battery room temperature.

The question states that 4160V switchgear room temperature is reading about 40 °F due to an unusually cold night. It does NOT address actual battery temperature. Furthermore, there is no information given that would lead one to believe that all equipment in the area has reached a thermal equilibrium with the room temperature.

However, both "a" and "b" are correct statements. Procedural actions to install temporary heating in the room in accordance with CC-MA-103-1001, requires a TCCP be initiated. Within the TCCP initiation procedure, the first step is to initiate an Action Request, if one has not already been written. This direction is given on page 7 of CC-MA-103-1001.

Both actions would be required to mitigate the room temperature problems and prevent the loss of the "C" battery.

Therefore, both "a" and "b" are correct.

References: Procedure 340.3, 125 Volt DC Distribution System C, pp. 2.0 and 16.0
CC-MA-103-1001, Implementation of Configuration Changes, pp. 1-8

QUESTION # SRO-7

It is a particularly cold January night. The Turbine Building Operator calls you up to let you know that the 4160 V switchgear room temperature is abnormally cool with a local room thermometer reading only about 40 degrees F.

What immediate action(s) are required?

A. Initiate a Temporary Configuration Change Package (TCCP) and install a portable heater in the room.

B. Initiate an Action Request to have install a portable heater in the room.

C. Conservatively, declare the 4160 Switchgear Room Fire Suppression System inoperable and assign a continuous Fire Watch in the room.

D. Determine the reactor must be placed in the COLD SHUTDOWN CONDITION while attempting to resolve any HVAC problems.

ANSWER: D

EXPLANATION:
With a 4160 V room temperature below 50 degrees F the "C" battery must be declared inoperable. With the "C" battery inoperable, TS 3.7.B requires "The reactor shall be placed in the COLD SHUTDOWN CONDITION...". Although the US may take other actions, the TS requirements must be initiated immediately and take precedence over other actions.

TECHNICAL REFERENCE(S): DC Distribution Lesson Plan page 4; TS pages 3.7-1 and 4.7-1 (Attach if not previously provided)

Proposed references to be provided to applicants during examination: None

Learning Objective: (01) 10445 (As available)

Examination Outline Cross-reference:

Level	RO	SRO
Tier #	___	1
Group #	___	1
K/A #	295004/2.1.33	
Importance Rating	___	4.0

K/A Topic Description: Ability to recognize indications of DC system operating parameters which are entry level conditions for Technical Specifications.

Question Source: Bank # ____
Modified Bank # ____ (Note changes or attached parent)
New X

Question Cognitive Level: Memory or Fundamental Knowledge ____
Comprehensive or Analysis X

10 CFR Part 55 Content: 55.41 ____
55.43 55.43(b)(2) and (3)

Comments: The applicant must combine at least three facts to obtain the right answer. Other equipment may be affected but that is not germane to the question.

PROCEDURE HISTORY

REV	DATE	ORIGINATOR	SUMMARY OF CHANGE
19	01/97	T. Corcoran	Add requirement to enter Technical Specification 3.7.A.4 LCO when transferring static chargers.
20	03/99	M. Heck	Added TABLE OF CONTENTS. Added REFERENCES section. Added GL 89-10 DC valve requirement steps. Added NORMAL OPERATION and ATTACHMENT sections. Made administrative changes to bring the procedure in line with the writer's standard. Added steps to address the tripping of Reactor Feed Pump A and Cleanup Recirc Pump A. Added steps to declare the C Battery inoperable if temperature limits are exceeded.
21	09/99	J. Freeman	Provide alternate guidance on static charger voltage adjustments and delete requirement for elect. maint. support.
22	11/99	M. Heck	Changed to add Tech Spec LCO numbers associated with MOV inoperability. Updated references. Added installation of jumpers when removing C Battery or C Distribution Center from service per CAPs 1998-1202 and 1998-1428.
23	10/00	M. Heck	Changed PM 25101O reference to PM 73501O. The rotation of the C Chargers has been moved from PM 25101O to PM 73501O.
24	11/01	M. Heck D. Lorentzen	Deleted all steps associated with 4160V Swgr jumpers. Revised C Battery Room operating temperatures to agree with Procedure 328.1. Added step for declaring C Battery inoperable below 124.2 VDC. Procedure Upgrade Project – format changes only.
25	09/02	J. Ruark	Adjust charger voltage to equalize charger voltage with bus voltage prior to closing charger output breaker (CAP O2002-1170)
26	02/03	M. Heck	Changed to declare C Battery inoperable based on battery temperature, not room temperature (CAP O2003-0046). Added clarification on where to read voltage values for several steps.

9.2.4 Battery capacity diminishes below 77°F. However, capacity at ≥ 50°F is acceptable due to available reserve. If any C Battery cell temperature drops below 50°F, C Battery shall be considered inoperable.

9.2.5 Accelerated loss of battery life occurs above 104°F. Battery damage may occur at 120°F. If Battery Room temperature increases to 120°F for more than 24 hours, C Battery shall be considered inoperable.

9.2.6 Do not place the static chargers C1 and C2 in parallel operation on Distribution Center C.

9.2.7 The battery is not to be disconnected from the C Distribution Center while the plant is > 212°F or operating at power.

9.2.8 Alarms for the 125 VDC System for C Battery are as follows:

1. Degraded Voltage Set Point 130.8 ± 0.2 Volts via BUS C UV (9XF-2-d)

2. Low Voltage Set Point 115 V ± 1 Volts via BAT CHG C1 TROUBLE (U-4-f) or BAT CHG C2 TROUBLE (U-5-f)

9.2.9 In order to maintain the seismic qualifications of the following switchgear/motor control centers, any breakers required to be racked out, shall be removed from their switchgear/motor control center cubicle and stored properly. During an outage, if the switchgear/motor control center is not required to be available, this precaution does not apply. Switchgear affected are 4160V 1C and 1D, Motor Control Centers 1A21, 1A21A, 1A21B, 1A23, 1A24, 1B21, 1B21A, 1B21B, 1B23, 1B24. DC-1, DC-2, and Vital Motor Control Centers 1A2, 1B2, and 1AB2.

9.2.10 With the DC Distribution Center C inoperable per Technical Specification 3.7.A.4, the following Technical Specifications also apply for the following reasons:

- 3.8.C, because V-14-35, Emergency Condenser NE01B Condensate Return Valve, is inoperable.
- 3.8.E, because V-14-33, Steam Inlet Valve to 'B' Emergency Condenser, is inoperable.

Exelon Nuclear

IMPLEMENTATION OF CONFIGURATION CHANGES

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1.0 PURPOSE

The purpose of this manual is to provide management expectations, suggested methods, and commonly accepted engineering and business practices for accurately and efficiently performing configuration changes. This manual is designed to complement the requirements contained in CC-AA-103, "Configuration Change Control," and CC-AA-104, "Document Change Requests." Where the requirements of CC-AA-103 and CC-AA-104 are self-explanatory, no additional guidance is provided in this manual.

NOTE: In general, this manual is organized to provide guidance based on the steps of the Design Change sub-process, as specified in CC-AA-103. It is understood that not all of the steps in the Design Change sub-process apply to the other sub-processes (e.g., the Commercial Change process or the Document Change Request process).

2.0 ENGINEERING EVALUATIONS

Requests to Engineering may not always require a configuration change as described in this manual. Technical evaluations or consulting may be provided outside of the configuration change process. Examples of this are:

- Technical evaluations dispositioned in accordance with CC-AA-309-101.
- Other requests for engineering support made via a PIMS A/R Evaluation

Attachment 1 of this manual provides additional guidance for proper use of PIMS Evaluations.

3.0 DETERMINATION OF APPLICABLE CONFIGURATION CHANGE TYPE
(CC-AA-103 Step 4.2) (CC-AA-104, Step 4.2)

CC-AA-103 contains direction for performing Commercial Changes, Equivalent Changes, and Design Changes.

CC-AA-104 contains direction for processing Administrative Change Document Change Requests (DCRs), Commercial Change DCRs, Equivalent Change DCRs, and Design Change DCRs.

If field work is required, then use CC-AA-103. If no field work is required, then use CC-AA-104.

In addition, there are types of configuration changes, such as the Pre-Engineered Change, that are not governed by either CC-AA-103 or CC-AA-104. The information provided in CC-AA-103 and its associated attachments direct the user to the sub-process and associated procedure or procedure section that is appropriate for the configuration change.

Nonconformances are processed per process description CC-AA-11. A nonconformance is entered into the corrective action process per LS-AA-125 and an operability evaluation is made using LS-AA-105. The operability evaluation includes identification of corrective actions and the time frame for completing the corrective actions. If a configuration change is required as one of the corrective actions, the change is made per the established configuration change procedures. A nonconformance does not impose any unique considerations related to development of the configuration change package. Since a repair disposition requires field work, use CC-AA-103 for the permanent disposition and use CC-AA-112 for an interim (temporary) disposition. Since a use-as-is disposition does not require field work, use CC-AA-104.

For information related to the applicability of setpoint changes to the configuration change process, refer to Attachment 2 of this manual.

3.1 **APPLICABILITY OF CONFIGURATION CHANGE SUB-PROCESSES (not covered by CC-AA-103)** (CC-AA-103, Step 4.2.1)

DOCUMENT CHANGE REQUEST (refer to CC-AA-104)

A label change is not considered field work since it does not require a clearance, work order, or testing. Therefore, a label change can be handled as a document change request. Issue a PIMS evaluation to have the label changed in the field.

TEMPORARY CONFIGURATION CHANGE (refer to CC-AA-112)

Temporary configuration changes include what used to be interim dispositions of nonconforming conditions at Peach Bottom and Limerick.

DESIGN ANALYSES

No additional guidance.

PRE-ENGINEERED CHANGE

Pre-Engineered Changes are alternatives to existing physical configurations in the facility that have been previously evaluated by Engineering and determined to meet or exceed installation and functional requirements of the System, Structure, or Component (SSC).

An example of a Pre-Engineered Solution would be the removal of a tubing support that was interfering with maintenance activities. The engineer would authorize support removal provided minimum support requirements were met as documented in an approved specification (e.g., spec NE-007 at PBAPS, SP 9000-44-001 at OC).

Another example of a Pre-Engineered Solution is the use of 125-1 evaluations at Oyster Creek and TMI. These evaluations historically prepared in accordance with OC/TMI Conduct of Engineering Principles provide alternate parts evaluations and resolution of installation issues.

Since the technical evaluation required to support a Pre-Engineered Change is contained in an approved specification or procedure, there is no need to generate a configuration change package (i.e., ECR) prior to performing the field work. Knowledgeable craft can refer to the associated work order for direction. Engineering may be required to provide a technical interpretation of the specification or procedure. Interpretations and clarifications are documented as an Engineering Technical Evaluation (refer to CC-AA-309-101) in an A/R evaluation.

Although a Pre-Engineered Change may provide a bounding technical evaluation, a Document Change Request may be required to assure configuration control. For example, removal of a piping support, while performed in accordance with a Maintenance procedure or specification, may require update of a controlled drawing, processed by a Document Change Request. Another use of a Document Change Request is to ensure that any required procedure or program updates are performed. If the revised document is required to support plant operation, the Document Change Request needs to be approved prior to installation.

Pre-Engineered Changes are implemented using the appropriate work control process (e.g., work orders, A/Rs).

ITEM EQUIVALENCY CHANGE (refer to SM-AA-300)

An Item Equivalency Change is a hardware change that does not change the performance of the design bases functions of the associated component or system, and does not change the item's or its applicable interfaces' compliance with the plant licensing bases. Item equivalency evaluations are performed in accordance with Procurement Engineering procedures through evaluation of form, fit, and function of replacement components or their piece parts. Refer to the applicable governing procedure for additional details.

3.2 **APPLICABILITY OF CONFIGURATION CHANGE SUB-PROCESSES (that are covered by CC-AA-103)** (CC-AA-103, Steps 4.2.2, 4.2.3, and 4.2.4)

COMMERCIAL CHANGE (refer to CC-AA-103, Section 4.3)

A Commercial Change implements a configuration change with fewer controls than a Design Change.

Commercial Changes are developed and implemented using codes, standards, and good engineering practices typically applied during the design of systems, structures, and components outside of nuclear jurisdiction. This includes use of national standards such as fire code, Uniform Building Code, National Electric Code, local and state standards, and other utility design standards.

An example of a Commercial Change would be alterations of the water treatment building lighting configuration (e.g., addition of fixtures).

Since the scope of a commercial change may vary from a simple change, such as the installation of a water fountain in the main control room, to a complex change, such as constructing a new warehouse building outside the protected area, the level of documentation and design team involvement will vary.

EQUIVALENT CHANGE (refer to CC-AA-103, Section 4.4)

No additional guidance.

<u>DESIGN CHANGE</u> (refer to CC-AA-103, Section 4.5)

A Design Change is any other type of configuration change that cannot be processed as a pre-engineered change, a temporary configuration change, a design analysis, an item equivalency, a document change request, a commercial change, or an equivalent change.

An example of a Design Change is the installation of a blank flange downstream of an inoperable Primary Containment Isolation Valve (PCIV). Since the blank flange provides the design bases isolation function differently than the PCIV, this type of configuration change is considered a Design Change.

It is intended that configuration changes with several portions be processed using "cafeteria style" execution, whereby the depth of documentation and review would be commensurate with the portion of the design change being considered. The following examples illustrate this concept:

Example 1, adding a water cooler to a safety related block wall. The portions of the configuration change related to changes to the block wall would be treated as a design change, whereas the portions related to the water cooler could be treated as a commercial change.

Example 2, adding non-safety related vibration monitors to a safety-related system. The portions of the configuration change related to seismic impact on the piping and components would be treated as a design change, whereas the portions related to the function of the vibration monitoring system could be treated as a commercial change.

Example 3, adding a non-safety related indicator to a safety-related control room panel. The portions of the configuration change related to the seismic analysis of the panel and human factors would be treated as a design change, whereas the portions related to the function of the indicator could be treated as a commercial change.

4.0 <u>CONFIGURATION CHANGE PACKAGE</u>

4.1 <u>PREPARATION OF CONFIGURATION CHANGE PACKAGES</u> (CC-AA-103, Step 4.5)

4.1.1. <u>PACKAGE CREATION</u> (CC-AA-104, Step 4.1.1)

Create an Action Request (A/R) in PIMS for the configuration change, if one has not already been created.

- Use a CM-ECR type A/R for all configuration changes that involve field work.
- Use an EC-ECR type A/R for all other configuration changes. This includes engineering work involved with developing pre-engineered changes that will be implemented by other A/Rs.

An Engineering Change Request (ECR) needs to be created in PIMS. If not already created by the Responsible Engineer's supervisor or the Initiator's supervisor, the Responsible

Engineer creates the ECR in PIMS. See Section 5.1 of this manual for guidance on creating an ECR. If all affected documents associated with an Administrative Change type of Document Change Request are issued in final form (i.e., no as-building required), it is acceptable to use an EVAL in lieu of an ECR.

The types of ECRs to choose from are as follows:

CONFIGURATION CHANGE SUB-PROCESS	ECR TYPE	CONTROLLING PROCEDURE
Item Equivalency	IEC	SM-AA-300
Administrative Change	ACP	CC-AA-104
Commercial Change	CCP	CC-AA-103, CC-AA-104
Equivalent Change	ECP	CC-AA-103, CC-AA-104
Design Change	DCP	CC-AA-103, CC-AA-104
Temporary Change	TCP	CC-AA-112

Note: Since a nonconformance does not receive any special treatment per the configuration change procedures, the NCR type of ECR is obsolete and is no longer used. If the A/R is a CM NCR type, create a child CM ECR or EC ECR type A/R to allow creating the proper type of ECR.

A configuration change may contain portions that meet the screening criteria for a less rigorous type of change package. In this case, it is acceptable to either use one ECR for the whole change or use multiple ECRs, one for each portion of the change. For example, some portions of a configuration change may be covered under a Design Change, while other portions meet the Commercial Change screening criteria. Either create a DCP type ECR and a CCP type to support the different portions of the configuration change, or create one DCP type ECR that contains limited attributes for the commercial change portion.

Use additional ECRs as necessary to divide the design work to support design, installation, and testing. Examples include:

- Unit specific changes to common documents, such as the UFSAR, Technical Specifications, and DBDs.
- Partial installation, acceptance testing, and as-building.
- Use by different installing organizations, such as contractors, Maintenance, and NMD.

There is basic information included in a configuration change package to assure that the users of the package understand what is being done and why it is being done. Although the procedure requires several items to be addressed in different contexts at different times, there is no need to repeat the same information in several places in the package. Therefore, a suggested general format for disposition of a configuration change is as follows:

Question SRO 12

The stated initial plant conditions cannot be met at Oyster Creek. With only three recirc pumps in operation, the pump speeds are limited to <33 HZ, which translates into a maximum power of no more than 55%. Therefore, we cannot and would not operate at 80% with three recirc pumps.

Considering the question with the given plant conditions, the stated transient **will** result in a reactor scram, either due to a loss of sufficient feedwater flow causing an automatic scram at 138 in., or a manual scram due to expected operator actions of ABN-17. These expected operator actions require a manual scram if a multiple feed or condensate pump trip occurs. Stated conditions are reactor power initially at 80% power, with a subsequent loss of bus 1B. This results in a loss of two condensate and two feedwater pumps.

For multiple feedwater or condensate pump trips, ABN-17 REQUIRES a reactor scram be inserted.

While the first part of suggested answer "a" is a correct statement (saying the plant would have scrammed from the transient), the second part of the statement is NOT true. The plant must be cooled down to a cold shutdown condition if the loss of the startup transformer lasts for longer than 7 days by Tech Spec section 3.7 dealing with AC power sources.

Therefore, there is no correct answer for this question, and the question should be deleted.

References: ABN-17, Feedwater System Abnormal Conditions, section 3.3 pg. 12
Technical Specifications, section 3.7

QUESTION # SRO-12

At noon on April 1, 2004 the plant is at 80% power with three reactor recirc pumps operating (NG01-A, C and E). **NO** LCOs are in effect at this time. At 12:05 PM the following conditions occur on the AC distribution system:

- The following alarms annunciate:
  - MN BRKR 1B TRIP
  - MN BRKR 1B 86 LKOUT TRIP
  - BUS 1B UV
  - S1B BRKR TRIP
  - S1B BRKR OL TRIP/BRKR PERM OPN
- 4160V BUS 1B voltmeter is reading downscale
- 4160V BUS 1A voltmeter is reading 4160 volts
- EDG No. 2 has started and has energized 4160V Bus 1D
- Security reports that Startup Transformer SB deluge system is discharging on the transformer.
- All other switchyard equipment is available for use.

challenge

The operators quickly respond to the 1B Bus alarms and indications (using OPS-3024.10a) and stabilize the plant within the design capability of the remaining energized systems and components. All applicable Technical Specification ACTION statements are satisfied.

Answer the following:

a. What is the maximum power level sustainable with the AC distribution configuration as it exists at 12:05 PM?

b. How long can the conditions existing at 12:05 PM be allowed to continue?

A. The plant would have scrammed from the transient. The existing conditions can be maintained indefinitely.

B. The plant could be run at approximately 33% power. The existing conditions can be maintained for 7 days.

C. The plant could be run at approximately 50% power. The existing conditions can be maintained for 7 days.

D. The plant could be run at approximately 33% power. The reactor must be placed in the COLD SHUTDOWN CONDITION.

ANSWER: B

EXPLANATION: The limiting configuration with Bus 1B deenergized is the condensate/feedwater system which will have only one condensate and one feedwater pump running. The remaining 4160V equipment (fed from Bus 1A) will sustain over 50% power. A half SCRAM will occur, but it can be reset after the #2 EDG loaded onto Bus 1D. It is expected that Bus 1B would be energized from the Station Blackout Transformer within about one hour. TS allows operation in this configuration for 7 days.

TECHNICAL REFERENCE(S): OPS-3024.10a; TS 3.7 (Attach if not previously provided)

Proposed references to be provided to applicants during examination: None

Learning Objective: ________ (As available)

Examination Outline Cross-reference:

Level	RO	SRO
Tier #	___	2
Group #	___	1
K/A #	262001/2.1.7	
Importance Rating	___	4.4

K/A Topic Description:
Ability to evaluate plant performance and make operational judgements related to AC Electrical Distribution based on operating characteristics/reactor behavior/ and instrument interpretation.

Question Source:
Bank # _____
Modified Bank # _____ (Note changes or attached parent)
New X

Question Cognitive Level:
Memory or Fundamental Knowledge _____
Comprehensive or Analysis X

10 CFR Part 55 Content:
55.41 _____
55.43 55.43(b)(5)and (2)

Comments: Sustainable power level must be validated by licensee.

D. **RESTORE and MAINTAIN** RPV level 155"-165". [ ]

E. **DIAGNOSE** the cause of the failure in accordance with section 3.3 of this procedure. [ ]

3.3 Loss of Feed/Feed Flow Abnormalities

A. Feed Pump Trip

PERFORM a rapid power reduction as directed by the Unit Supervisor.

B. Condensate Pump Trip

PERFORM a rapid power reduction as directed by the Unit Supervisor.

C. Multiple Feed Pumps Trip

1) **SCRAM** the reactor **and EXECUTE** ABN-1. [ ]

D. Multiple Condensate Pumps Trip

1) **SCRAM** the reactor **and EXECUTE** ABN-1. [ ]

E. Feed Flow Abnormalities

1) **CHECK** feed pump and associated valves lined up correctly. [ ]

2) **If** the block valve(s) are misaligned as indicated by:

- Individual feedwater flow in the 'A' **or** 'C' string unbalanced.
- BLOCK VLV TROUBLE annunciators in alarm (J-6-d (f)).

3.7 AUXILIARY ELECTRICAL POWER

Applicability: Applies to the OPERATING status of the auxiliary electrical power supply.

Objective: To assure the OPERABILITY of the auxiliary electrical power supply.

Specifications:

A. The reactor shall not be made critical unless all of the following requirements are satisfied:

1. The following buses or panels energized.

   a. 4160 volt buses 1C and 1D in the turbine building switchgear room.

   b. 460 volt buses 1A2, 1B2, 1A21, 1B21 vital MCC 1A2 and 1B2 in the reactor building switchgear room: 1A3 and 1B3 at the intake structure; 1A21A, 1B21A, 1A21B, and 1B21B and vital MCC 1AB2 on 23'6" elevation in the reactor building; 1A24 and 1B24 at the stack.

   c. 208/120 volt panels 3, 4, 4A, 4B, 4C and VACP-1 in the reactor building switchgear room.

   d. 120 volt protection panel 1 and 2 in the cable room.

   e. 125 volt DC distribution centers C and B, and panel D, Panel DC-F, isolation valve motor control center DC-1 and 125V DC motor control center DC-2.

   f. 24 volt D.C. power panels A and B in the cable room.

2. One 230 KV line is fully operational and switch gear and both startup transformers are energized to carry power to the station 4160 volt AC buses and carry power to or away from the plant.

3. An additional source of power consisting of one of the following is in service connected to feed the appropriate plant 4160 V bus or buses:

   a. A 69 KV line fully operational.

   b. A 34.5 KV line fully operational.

4. Station batteries B and C and an associated battery charger are OPERABLE. Switchgear control power for 4160 volt bus 1D and 460 volt buses 1B2 and 1B3 are provided by battery B. Switchgear control power for 4160 volt bus 1C and 460 volt buses 1A2 and 1A3 are provided by battery C.

5. Bus tie breakers ED and EC are in the open position.

B. The reactor shall be PLACED IN the COLD SHUTDOWN CONDITION if the availability of power falls below that required by Specification A above, except that

1. The reactor may remain in operation for a period

not to exceed 7 days if a startup transformer is out of service. None of the engineered safety feature equipment fed by the remaining transformer may be out of service.

2. The reactor may remain in operation for a period not to exceed 7 days if 125 VDC Motor Control Center DC-2 is out of service, provided the requirements of Specification 3.8 are met.

C. Standby Diesel Generators

1. The reactor shall not be made critical unless both diesel generators are operable and capable of feeding their designated 4160 volt buses.

2. If one diesel generator becomes inoperable during power operation, repairs shall be initiated immediately and the other diesel shall be operated at least one hour every 24 hours at greater than 80% rated load until repairs are completed. The reactor may remain in operation for a period not to exceed 7 days if a diesel generator is out of service. During the repair period none of the engineered safety features normally fed by the operational diesel generator may be out of service or the reactor shall be placed in the cold shutdown condition. If a diesel is made inoperable for biennial inspection, the testing and engineered safety feature requirements described above must be met.

3. If both diesel generators become inoperable during power operation, the reactor shall be placed in the cold shutdown condition.

4. For the diesel generators to be considered operable:

A) There shall be a minimum of 14,000 gallons of diesel fuel in the standby diesel generator fuel tank,

OR

B) To facilitate inspection, repair, or replacement of equipment which would require full or partial draining of the standby diesel generator fuel tank, the following conditions must be met:

1) There shall be a minimum of 14,000 gallons of fuel oil contained in temporary tanker trucks, connected and aligned to the diesel generator fill station.

Question SRO 22

Per Category J, "Radiological Releases":

- Iodine release greater than 40 μCi/sec is an ALERT classification
- Valid integrated dose at or beyond the site boundary of ≥5 mREM but ≤1000 mREM TEDE is a SITE AREA EMERGENCY classification

Based upon the HP call of 700 mREM[/hr] TEDE at the route 9 bridge, this constitutes a SITE AREA EMERGENCY, not a GENERAL EMERGENCY.

Therefore, answer "b" is the correct answer.

References: EPIP-OC-.01, Classification of Emergency Events, Category J

QUESTION # SRO-22

One hour has elapsed since a steam line break occurred in the Turbine Building. The transient has caused fuel damage, a reactor scram, but manual closure of the MSIVs was NOT successful. Following the transient the following conditions exist:

- All rods reached 00 on the SCRAM
- Torus temperature is 96 degrees F
- There is indication of 50,000 lbs/hr flow on the "A" main steam line flow instrument
- RPV level is 60" TAF and slowly increasing from a low point of 30" TAF
- RPV pressure is 760 psig and dropping slowly
- Security calls and informs you that steam can be seen issuing from, the Turbine Building
- Chemistry sampling results of reactor coolant are NOT in yet but the accompanying HP reported that the sample bottle was 5 R/HR when the chemist left the sample station
- Iodine release is 50 uCI/sec
- An HP calls from Route 9 bridge and reports 700 mREM/hr TEDE at his location

Classify the event.

A. General Emergency

B. Site Area Emergency

C. Alert

D. Unusual Event

ANSWER: A

EXPLANATION: The key factors are the MSIVs not closed and the last data from the HP which satisfies GE. The remaining indications all satisfy UE or ALERT.

TECHNICAL REFERENCE(S): Procedure EPIP-OC-01, Classification of Emergency Conditions, Appendix 1 (Attach if not previously provided)

Proposed references to be provided to applicants during examination: EPIP-OC-01 Appendix 1

Learning Objective: ________________ (As available)

Examination Outline Cross-reference:

Level	RO	SRO
Tier #	___	3
Group #	___	4
K/A #	2.4.41	
Importance Rating	___	4.1

K/A Topic Description: Knowledge of the emergency action level thresholds and classifications

Question Source:

Bank # X

Modified Bank # _____ (Note changes or attached parent)

New _____

Question Cognitive Level:	Memory or Fundamental Knowledge	____
	Comprehensive or Analysis	X
10 CFR Part 55 Content:	55.41 ____	
	55.43 55.43(b)(5) and (4)	

Comments: INPO bank Susquehanna 9/30/99. Changed units and terminology to OC specific.

APPENDIX 2

Category J "Radiological Releases"

(J) Condition Applicability — ***All Plant Conditions.***

Basis — ***This covers any event which leads to a rad release regardless of plant condition.***

Classifications — Unusual Event

EAL's

1. Noble Gas: Stack Monitor greater than CPS_{UE}

-or-

2. Iodine: Release rate greater than 4 uCi/sec

-or-

3. 10 CFR 20, Appendix B, Table 2, Column 2, limits exceeded in discharge canal at Rt. 9 Bridge

-or-

Off-site Dose:

4. A valid integrated dose at or beyond the Site Boundary of greater than or equal to 0.1 mRem total whole body (TEDE) but less than 10 mRem total whole body dose (TEDE) exists as indicated by: dose projections or field team readings

-or-

5. A valid integrated dose at or beyond the Site Boundary of greater than or equal to 0.5 mRem (CDE) adult thyroid but less than 50 mRem (CDE) adult thyroid dose exists as indicated by: dose projections or field team readings.

Basis

Unplanned releases in excess of the site technical specifications that continue for 5 minutes or longer represent a potential degradation in the level of safety. The final integrated dose is not the primary concern here, it is the degradation in plant control implied by the fact that the release was not isolated.

The term "Unplanned", as used in this context, includes any release for which a radioactive discharge permit was not prepared, or a release that exceeds the conditions (e.g., minimum dilution flow, maximum discharge flow, alarm setpoints, etc.) on the applicable permit.

Offsite Dose due to plant releases (<u>readings above background</u>) can be determined from field measurement readings or dose projections. Monitor indications are calculated on the basis of the methodology of the Offsite Dose Calculation Manual (ODCM), which demonstrates compliance with 10CFR20 and/or 10CFR50 Appendix I requirements.

In EAL 4, the 0.1 mR value is based on a proration of two times the 500 mR/yr for an individual member of the public stated in the Oyster Creek Off-Site Dose Calculation Manual, rounded down to 0.1 mRem per event.

APPENDIX 2

Category J "Radiological Releases"

Classification Alert

EAL's

1. Noble Gas: Stack Monitor greater than CPS_A

-or-

2. Iodine: Release rate greater than 40 uCi/sec

-or-

3. 10 CFR 20, Appendix B, Table 2, Column 2, Limits exceeded by a factor of 10 in discharge canal at Rt. 9 Bridge.

-or-

Offsite Dose:

4. A valid integrated dose at or beyond the Site Boundary of greater than or equal to 10 mRem but less than 50 mRem total whole body dose (TEDE) exists as indicated by: dose projections or field team readings.

-or-

5. A valid integrated dose at or beyond the Site Boundary of greater than or equal to 50 mRem but less than 250 mRem (CDE) adult thyroid dose exists as indicated by: dose projections or field team readings.

Basis

This event escalates from the Unusual Event by escalating the magnitude of the release by a factor of 10. In EAL 3, the 10.0 mR/hr value is based on a proration of 200 times the 500 mR/Yr limit for an individual member of the public stated in the Oyster Creek Off-Site Dose Calculation Manual, rounded down to 10.0 mR/hr. EALs' at this level or higher are entry conditions to Procedure EMG-3200.12.

Classification Site Area Emergency

EAL's Offsite Dose:

4. A valid integrated dose at or beyond the Site Boundary of greater than or equal to 50 mRem but less than 1000 mRem (1 Rem) total whole body dose (TEDE) exists as indicated by: dose projections or field team readings.

-or-

5. A valid integrated dose at or beyond the Site Boundary of greater than or equal to 250 mRem but less 5000 mRem (5 Rem) (CDE) adult thyroid exists as indicated by: dose projections or field team readings.

Basis

The 50 mRem is based on the corporate philosophy for classification relative to the EPA's protective action guidelines, where 5% of the lower limit shall be the trigger value for a Site Area Emergency. The 250 mRem child thyroid dose is in consideration of the 1:5 ratio established by the PAG's for total whole body dose (TEDE) to (CDE) adult thyroid relationship.

APPENDIX 2

Category J "Radiological Releases"

Classification General Emergency

EAL's

Offsite Dose:

4. A valid integrated dose at or beyond the Site Boundary of greater than or equal to 1000 mRem (1 Rem) total whole body dose (TEDE) exists as indicated by: dose projections or field team readings.

-or-

5. A valid integrated dose at or beyond the Site Boundary of greater than or equal to 5000 mRem (5 Rem) (CDE) adult thyroid exists as indicated by: dose projections or field team readings.

Basis

The 1000 mRem total whole body (TEDE) and the 5000 mRem (CDE) adult thyroid integrated dose are based on the proposed EPA protective action guidance which indicates that public protective actions are warranted if the dose exceeds 1 rem total whole body (TEDE) or 5 rem (CDE) adult thyroid. This is consistent with the emergency class description for a General Emergency and the Nureg's initiating conditions. Actual meteorology (including forecasts) should be used.

Question SRO 23

Based upon the given information, there are 30,500 gallons of diesel fuel available for diesel engine operation. At the 3-day fuel consumption rate per Amendment 18, it comes out to 7.37 days of available fuel oil. The question, as written, assumes the Diesel Fuel Oil tank must be maintained at 14,500 gallons. Technical Specifications bases for section 3.7 assumes the EDG's are available to be run as long as the fuel supply holds out. The fuel supply takes into consideration the Diesel Fuel Oil tank, as well as the heating boiler fuel supply. Therefore, taking into consideration 14,000 gallons in the fuel oil tank and 16,500 in the heating boiler tank, there is a total of 30,500 gallons, NOT just 16,500 as stated in the question explanation.

The 3-day consumption rate is 12,410 gallons of fuel oil, which equates to 4,136.66 gallons per day. By dividing 30,500 gallons by 4136.66 gal/day, the total time is 7.37 days of operation.

The question asks: "How long is the fuel supply adequate, considering the TS Basis consumption rate."

Since the question is not looking for the longest time the diesels will run with the available fuel supply, ALL four answers can be considered correct (3 days, 4 days, 5 days, 7 days.) Under all cases, the supply is adequate to cover all four answers.

This question should be deleted.

References: Technical Specifications, section 3.7 including bases

QUESTION #SRO-23

The plant is in normal full power operation with no LCOs on April 1, 2004 when massive grid instabilities result in the loss of offsite power for the foreseeable future. The plant responds as designed including both Standby Diesel Generators which have started and loaded to their respective buses. The following conditions exist as of noon on April 1, 2004:

- Diesel fuel oil delivery is uncertain due to infrastructure problems
- The Standby Diesel Generator Fuel Tank is at 14,500 gallons
- The heating boiler tank has 16,500 gallons of available fuel
- **NO** other sources of diesel fuel are available on site
- The heating boilers are shutdown for maintenance

How long is the fuel supply adequate considering the TS Basis consumption rate?

For your answer assume two diesels continue to run at the consumption rate specified in Amendment 18. Round off you answer to the nearest day.

A. Three days

B. Four days

C. Five days

D. Seven days

ANSWER: B

EXPLANATION: Per TS Bases the rate is 12,410 gallons for three days. The 16, 500 gallons in the heating boiler tank will last three days and 23+ hours (16,546 gallons for four days) with the Standby Diesel Generator Fuel Tank maintained above its TS minimum level of 14,000 gallons.

TECHNICAL REFERENCE(S): TS 3.7.C and TS Bases for TS 3.7 (Attach if not previously provided)

Proposed references to be provided to applicants during examination: None

Learning Objective: ____________ (As available)

Examination Outline Cross-reference:

Level	RO	SRO
Tier #	___	3
Group #	___	1
K/A #	2.1.33	
Importance Rating	___	4.0

K/A Topic Description:
Ability to recognize indications for system operating parameters which are entry conditions for Technical Specifications

Question Source: Bank # X
Modified Bank # _____ (Note changes or attached parent)
New _____

Question Cognitive Level:	Memory or Fundamental Knowledge	____
	Comprehensive or Analysis	X
10 CFR Part 55 Content:	55.41 ____	
	55.43 55.43(b)(2)	

Comments: Used INPO bank question from Duane Arnold 5/25/99. Made values and terminology consistent with OC Tech Specs

not to exceed 7 days if a startup transformer is out of service. None of the engineered safety feature equipment fed by the remaining transformer may be out of service.

2. The reactor may remain in operation for a period not to exceed 7 days if 125 VDC Motor Control Center DC-2 is out of service, provided the requirements of Specification 3.8 are met.

C. Standby Diesel Generators

1. The reactor shall not be made critical unless both diesel generators are operable and capable of feeding their designated 4160 volt buses.

2. If one diesel generator becomes inoperable during power operation, repairs shall be initiated immediately and the other diesel shall be operated at least one hour every 24 hours at greater than 80% rated load until repairs are completed. The reactor may remain in operation for a period not to exceed 7 days if a diesel generator is out of service. During the repair period none of the engineered safety features normally fed by the operational diesel generator may be out of service or the reactor shall be placed in the cold shutdown condition. If a diesel is made inoperable for biennial inspection, the testing and engineered safety feature requirements described above must be met.

3. If both diesel generators become inoperable during power operation, the reactor shall be placed in the cold shutdown condition.

4. For the diesel generators to be considered operable:

A) There shall be a minimum of 14,000 gallons of diesel fuel in the standby diesel generator fuel tank,

OR

B) To facilitate inspection, repair, or replacement of equipment which would require full or partial draining of the standby diesel generator fuel tank, the following conditions must be met:

1) There shall be a minimum of 14,000 gallons of fuel oil contained in temporary tanker trucks, connected and aligned to the diesel generator fill station.

-AND-

2) The reactor cavity shall be flooded above elevation 117 feet with the spent fuel pool gates removed, or all reactor fuel shall be contained in the spent fuel pool with spent fuel pool gates installed.

AND

3) The plant shall be placed in a configuration in which the core spray system is not required to be OPERABLE.

Bases

The general objective is to assure an adequate supply of power with at least one active and one standby source of power available for operation of equipment required for a safe plant shutdown, to maintain the plant in a safe shutdown condition and to operate the required engineered safety feature equipment following an accident.

AC power for shutdown and operation of engineered safety feature equipment can be provided by any of three active (one or two 230 KV lines, one 69 KV line, and one 34.5 KV line) and either of two standby (two diesel generators) sources of power. (In applying the minimum requirement of one active and one standby source of AC power, since both 230 KV lines are on the same set of towers, either one or both 230 KV lines are considered as a single active source.) Normally all six sources are available. However, to provide for maintenance and repair of equipment and still have redundancy of power sources the requirement of one active and one standby source of power was established. The plant's main generator is not given credit as a source since it is not available during shutdown.

The plant 125V DC system consists of three batteries and associated distribution system. Batteries B and C are designated as the safety related subsystems while battery A is designated as a non-safety related subsystem. Safety related loads are supplied by batteries B and C, each with two associated full capacity chargers. One charger on each battery is in service at all times with the second charger available in the event of charger failure. These chargers are active sources and supply the normal 125V DC requirements with the batteries and standby sources. (1)

The probability analysis in Appendix "L" of the FDSAR was based on one diesel and shows that even with only one diesel the probability of requiring engineered safety features at the same time as the second diesel fails is quite small. The analysis used information on peaking diesels when synchronization was required which is not the case for Oyster Creek. Also the daily test of the second diesel when one is temporarily out of service tends to improve the reliability as does the fact that synchronization is not required.

As indicated in Amendment 18 to the Licensing Application, there are numerous sources of diesel fuel which can be obtained within 6 to 12 hours and the heating boiler fuel in a 75,000 gallon tank on the site could also be used. As indicated in Amendment 32 of the Licensing Application and including the Security System loads, the load requirement for the loss of offsite power would require 12,410 gallons for a three day supply. For the case of loss of offsite power plus loss-of-coolant plus bus failure 9790 gallons would be required for a three day supply.

In the case of loss of offsite power plus loss-of-coolant with both diesel generators starting the load requirements (all equipment operating) shown there would not be three days' supply. However, not all of this load is required for three days and, after evaluation of the conditions, loads not required on the diesel will be curtailed. It is reasonable to expect that within 8 hours conditions can be evaluated and the following loads curtailed:

1. One Core Spray Pump
2. One Core Spray Booster Pump
3. One Control Rod Drive Pump
4. One Containment Spray Pump
5. One Emergency Service Water Pump

With these pieces of equipment taken off at 8 hours after the incident it would require a total consumption of 12,840 gallons for a three day supply. Therefore, a minimum technical specification requirement of 14,000 gallons of diesel fuel in the standby diesel generator fuel tank will exceed the engineered safety features operational requirement after an accident by approximately 9%.

During plant cold shutdown or refueling, it may be necessary to inspect, repair and replace the 15,000 gallon standby diesel generator fuel storage tank. This would require tank partial or full drain down. An alternate fuel supply configuration may be established which consists of temporary tanker trucks capable of containing 14,000 gallons. This configuration is capable of supporting continuous operation of both diesels for at least 3 days.

The temporary configuration is acceptable since a minimal power load would be required during and following a design basis condition of a loss of offsite power while the plant is in cold shutdown or refueling. Analysis shows that in the event of a tornado or seismic event which may cause a loss of offsite power and a temporary loss of the temporary EDG fuel oil supply, power can be restored before the consequences of previously analyzed conditions are exceeded.

References:

(1) Letter, Ivan R. Finfrock, Jr. to the Director of Nuclear Reactor Regulation dated April 4, 1978.

Question SRO 25

Step 7.2.4 of procedure 312.9 (precautions and limitations) says " . . . If the primary Containment requires venting and the potential exists for airborne activity to be higher than normal, consideration should be given to vent through the Standby Gas Treatment System."

Step 7.3.2.6 (steps to depressurize the Torus) says "IF stack gas activity exceeds 1000 cps, THEN immediately SECURE the purge.

a. CLOSE Torus Vent V-28-17
b. CLOSE Torus Vent V-28-18
c. NOTIFY the OS

The suggested answer to the question was "c", to secure the primary containment purge by closing V-28-17 and V-28-18.

The candidates were only provided sections 7.1 and 7.2 of procedure 312.9, hence they all chose the answer dealing with the above-stated precaution to vent through Standby Gas Treatment System. It is not expected for the candidates to memorize a discrete action setpoint contained within an operating procedure, especially if it is a setpoint that is not readily recognized. The answer the students chose was based upon the supplied sections of the procedure. The suggested correct answer was derived from that section of the procedure that was not available to the students.

Therefore, answers "c" and "d" are correct based upon the provided references.

References: Procedure 312.9, Primary Containment

QUESTION #SRO-25

A drywell entry must be made in order to inspect for increased unidentified leakage. A plant shutdown is in progress. The following conditions exist:

- Reactor Power is 90% and decreasing
- Purging of the drywell with air is in progress in accordance with Procedure 312.9, "Primary Containment Control".
- The Chemistry Department indicated that the Stack Gas Activity should **NOT** exceed 900 CPS, based on their sample
- DRYWELL VENT-PURGE INTERLOCK BYPASS switch is in the BYPASS position (Panel 12XR)
- Venting is via the Reactor Building Ventilation System
- Stack gas activity is at 1100 CPS and slowly increasing

Your direction to the operator(s) controlling the purge in accordance with Procedure 312.9 is that they are required to:

A. Decrease the purge flow until stack gas activity decreases below 900 CPM

B. Confirm stack release rate with RAGEMS and then decrease purge flow rate.

C. Secure the primary containment purge by closing V-28-17 and V-28-18.

D. Shift the purge to go through the Standby Gas Treatment System

ANSWER: C

EXPLANATION: This is specified in Step 7.3.2.6 of Procedure 312.9. The other distractors, though possible mitigation strategies, are not specified actions.

TECHNICAL REFERENCE(S): Section 7.0 of Procedure 312.9 (Attach if not previously provided)

Proposed references to be provided to applicants during examination: Section 7.1 and 7.2 of Procedure 312.9

Learning Objective: __________ (As available)

Examination Outline Cross-reference:

Level	RO	SRO
Tier #	___	3
Group #	___	3
K/A #	2.3.9	
Importance Rating	___	3.4

K/A Topic Description: Knowledge of the process for performing a Containment Purge

Question Source:
Bank # _____
Modified Bank # _____ (Note changes or attached parent)
New X

Question Cognitive Level:
Memory or Fundamental Knowledge X
Comprehensive or Analysis _____

10 CFR Part 55 Content: 55.41 ____
55.43 55.43(b)(4)

Comments:

7.0 PURGING PRIMARY CONTAINMENT WITH AIR

7.1 Prerequisites

7.1.1 The Instrument and Service Air System is in operation in accordance with Procedure 334. [ ]

7.1.2 The Reactor Building Heating, Cooling and Ventilation System is in operation in accordance with Procedure 329. [ ]

7.1.3 The Process Radiation Monitoring System is in operation in accordance with Procedures 406.1 and 406.2. [ ]

7.1.4 The Chemistry Department has evaluated Reactor Coolant activity in accordance with procedure 829.10 step 9.3 and taken an air sample if required. If a sample is required, it has been analyzed for radioactivity and the Primary Containment atmosphere has been found satisfactory for purging via the Reactor Building Ventilation System. [ ]

7.1.5 The Stack RAGEMS is in operation in accordance with Procedure 406.8. [ ]

7.1.6 Hydrogen concentration in the Drywell has been verified to be less than 2% prior to purging. If it is greater than or equal to 2%, the Drywell must be inerted to less than 2% H_2 concentration in accordance with Procedure 312.11. The preferred method of verification is the H_2/O_2 monitor. [ ]

7.2 Precautions and Limitations

7.2.1 Drywell entries shall be controlled in accordance with Procedure 233.

7.2.2 When purging in the RUN mode, the DRYWELL VENT-PURGE INTERLOCK BYPASS switch must be in the BYPASS position (Panel 12XR).

7.2.3 Normal containment purging will be via the Reactor Building Ventilation System. Purging following the release of Reactor steam/water to the containment and subsequent Containment Isolation shall be controlled by the Emergency Operating Procedures.

7.2.4 Stack and Reactor Building Radiation Monitors shall be monitored whenever the Primary Containment is being vented. If the Primary Containment requires venting and the potential exist for airborne activity to be higher than normal, consideration should be given to vent through the Standby Gas Treatment System.

7.2.5 Primary Containment de-inerting may commence 24 hours prior to a scheduled shutdown in accordance with Tech. Spec. 3.5.A.6.

7.2.6 When Primary Containment is required, simultaneous opening of Drywell and Torus valves listed together in Groups I or II or III in the table below is prohibited. Operating with both Drywell and Torus valves open creates a pathway to bypass the Torus to Drywell Vacuum Breakers (**CM-2**).

Group		Drywell	Torus
I	N_2 Purge (12XR)	V-23-13 V-23-14	V-23-15 V-23-16
II	N_2 Makeup (12XR)	V-23-17 V-23-18	V-23-19 V-23-20
III	Ventilation Valves (Exhaust)	V-27-1 V-27-2 V-23-21 V-23-22	V-28-17 V-28-18 V-28-47

7.3 Instructions

7.3.1 **ISOLATE** nitrogen to the Drywell and Torus and **SWITCH** to 100 psig air.

7.3.1.1 **PERFORM** the following steps to isolate N_2 to the Drywell and Torus:

1. **CONFIRM** open 100 psig air supply valve V-6-166 (in Shutdown Cooling Pump Room west wall by the pumps). [ ]

2. NOTE

   The following step will cause the N2 indicator to extinguish, the AIR indicator to illuminate and the N2 COMPR FAIL (C-3-g) alarm to annunciate in the Control Room.

   SELECT AIR with the AIR/N2 selector switch at the nitrogen compressors. [ ]

3. **OPEN** Nitrogen Compressor #1 local disconnect switch. [ ]

4. **OPEN** Nitrogen Compressor #2 local disconnect switch. [ ]

5. **CLOSE** the following nitrogen valves:

   - Nitrogen Compressor #1 Supply Valve V-23-1002. [ ]
   - Nitrogen Compressor #2 Supply Valve V-23-1001. [ ]
   - Nitrogen Compressor #1 Discharge Valve V-23-170. [ ]
   - Nitrogen Compressor #2 Discharge Valve V-23-171. [ ]
   - Nitrogen Receiver Discharger Valve V-23-169. [ ]

6. **OPEN** the Nitrogen Receiver Drain Valve V-23-177 and completely **VENT** the receiver. [ ]

7.3.1.2 **TRANSFER** purge gas to the TIP tubes from nitrogen to air as follows:

1. **OPEN** the instrument air supply to the TIP indexers V-6-1321. (Tip Drive Room) [ ]

2. **CLOSE** the nitrogen supply to the TIP indexers V-23-163. (Tip Drive Room) [ ]

3. **ADJUST** Pressure Regulating Valve V-23-69 to obtain 0.8 to 1.2 as read on DPI-23-278 (RB 23'). [ ]

7.3.1.3 **CONFIRM** closed the following nitrogen makeup and purge valves (Panel 12XR):

- DRYWELL N2 MAKEUP V-23-17 [ ]
- DRYWELL N2 MAKEUP V-23-18 [ ]
- DRYWELL N2 PURGE PRESSURE CONTROL V-23-13 [ ]
- DRYWELL N2 PURGE SHUTOFF V-23-14 [ ]
- TORUS N2 MAKEUP V-23-19 [ ]
- TORUS N2 MAKEUP V-23-20 [ ]
- TORUS N2 PURGE PRESSURE CONTROL V-23-15 [ ]
- TORUS N2 PURGE SHUTOFF V-23-16 [ ]

7.3.1.4 **PLACE** the Drywell Oxygen Analyzer and Torus Oxygen Analyzer Sample Pump in service in accordance with Procedure 312.7. [ ]

7.3.1.5 **CONFIRM** CNTMT VENT AND PURGE ISOLATION BYPASS switch (lower left side) in NORMAL position (Panel 11F). [ ]

7.3.2 **DEPRESSURIZE** the Torus as follows:

1. **CONFIRM** closed Drywell Vent and Bypass valves:
   - V-23-21 [ ]
   - V-23-22 [ ]
   - V-27-1 [ ]
   - V-27-2 [ ]

2. <u>IF</u> the REACTOR MODE SELECTOR switch is in the RUN position,

   <u>THEN</u> **PLACE** DRYWELL VENT-PURGE INTERLOCK BYPASS switch in BYPASS position (Panel 12XR). [ ]

3. **OPEN** Torus Vent valves (Panel 11F):
   - V-28-17 [ ]
   - V-28-18 [ ]

4. **MONITOR** the following:
   - Reactor Building ventilation exhaust activity (Panel 10F)
   - stack gas activity (Panel 10F)
   - stack gas activity (Panel 1R)

5. **MARK** the time the depressurization was started on the stack gas recorder (Panel 10F). [ ]

6. IF stack gas activity exceeds 1000 cps,

   THEN immediately **SECURE** the purge:

   a. **CLOSE** Torus Vent V-28-17 [ ]

   b. **CLOSE** Torus Vent V-28-18 [ ]

   c. **NOTIFY** the OS [ ]

7. **VERIFY** Torus pressure is approximately zero as indicated on the pressure recorder (Panel 12XR). [ ]

8. **CLOSE** Torus Vent valves (Panel 11F):

   - V-28-17 [ ]
   - V-28-18 [ ]

7.3.3 **DEPRESSURIZE** the Drywell as follows:

1. **CONFIRM** closed Torus Vent and Bypass valves (Panel 11F):

   - V-28-17 [ ]
   - V-28-18 [ ]
   - V-28-47 [ ]

2. IF the REACTOR MODE SELECTOR switch is in the RUN position,

   THEN **PLACE** the DRYWELL VENT-PURGE INTERLOCK BYPASS switch in BYPASS position (Panel 12XR). [ ]

3.

CAUTION

Torus and Drywell pressure must be monitored while purging the Drywell. This ensures a positive ΔP is maintained between Drywell and Torus to prevent opening the Torus to Drywell vacuum breakers.

OPEN Drywell Vent valves (Panel 11F):

- V-27-1 [ ]
- V-27-2 [ ]

4. IF while Drywell purging is in progress, Torus pressure increases sufficiently to approach the opening of the Torus to Drywell vacuum breakers,

   THEN **PERFORM** the following:

   a. **CLOSE** Drywell Vent valves:

      - V-27-1 [ ]
      - V-27-2 [ ]

   b. **RETURN** to Step 7.3.2 to purge the Torus. [ ]

5. **MONITOR** the following:

   a. Reactor Building ventilation exhaust activity (Panel 10F)

   b. Stack gas activity (Panel 1R)

6. **MARK** the time the depressurization was started on the stack gas recorder (Panel 10F). [ ]

7. IF stack gas activity exceeds 1000 cps,
   THEN immediately **SECURE** the purge:

   a. **CLOSE** Drywell Vent V-27-1. [ ]

   b. **CLOSE** Drywell Vent V-27-2. [ ]

   c. **NOTIFY** the OS. [ ]

8. WHEN the drywell pressure is approximately 0 psi,

   THEN **CLOSE** Drywell Vent valves (Panel 11F):

   - V-27-1 [ ]
   - V-27-2 [ ]

7.3.4

> NOTE
>
> Steps 7.3.4, 7.3.5, 7.3.6, and 7.3.7 can be performed in any order as determined by the OS.

PURGE the Drywell with air as follows:

1. WHEN Drywell pressure has been reduced to approximately zero as indicated on the pressure recorder on Panel 12XR,

   THEN **PERFORM** the following:

   a. **CONFIRM** closed Torus Vent and Bypass valves (Panel 11F):

   - V-28-17 [ ]
   - V-28-18 [ ]
   - V-28-47 [ ]

b. **OPEN** the following valves:

- MAIN SUPPLY HEADER VALVES TO DW V-28-42 and V-28-43 (Panel 11R) [ ]
- DW PURGE V-27-3 [ ]
- DW PURGE V-27-4 [ ]
- DW VENT V-27-1 [ ]
- DW VENT V-27-2 [ ]

7.3.5 **SECURE** the Nitrogen Purge System as follows:

1. **CLOSE** Grove Reducer Pressure Regulator V-23-234 or V-23-235 by turning its stem fully counter clockwise. [ ]
2. **CLOSE** Nitrogen Vaporizer Supply Valve V-23-268. [ ]
3. **CLOSE** Thermostatic Control Valve Inlet Valve V-23-186. [ ]
4. **CLOSE** Thermostatic Control Valve Outlet Valve V-23-187. [ ]
5. **CLOSE** Inlet to #1 Grove Reducer Valve V-23-189. [ ]
6. **CLOSE** Inlet to #2 Grove Reducer Valve V-23-190. [ ]
7. **CLOSE** Outlet from #1 Grove Reducer Valve V-23-191. [ ]
8. **CLOSE** Outlet from #2 Grove Reducer Valve V-23-192. [ ]
9. **PLACE** the Nitrogen Vaporizer Power Control Switch to the STOP position. [ ]
10. **PLACE** the selected heater power control switch to OFF. [ ]

11. **PLACE** the following power circuit breaker switches to the OFF position:
    - HTR-854-165 [ ]
    - HTR-854-166 [ ]
    - M-23-1 [ ]
12. **OPEN** N2 Purge Line Drain Valve V-23-143. (Outside Reactor Building NE corner). [ ]
13. **OPEN** Purge Header Drain Trap Inlet Valve V-23-263. (Reactor Building NE Stairwell). [ ]
14. **OPEN** Purge Header Drain Trap Vent Valve V-23-362. (Reactor Building NE Stairwell). [ ]
15. **PERFORM** the Nitrogen System Shutdown Valve Lineup, Attachment 312.11-3. [ ]

7.3.6 WHEN Primary Containment is **no** longer required,

THEN **PURGE** the Torus as follows:

1. **OPEN** Torus Vent valves:
    - V-28-17 [ ]
    - V-28-18 [ ]
2. **OPEN** Reactor Bldg to Torus Vacuum Breaker valves (Panel 11F):
    - V-26-16 [ ]
    - V-26-18 [ ]

3. **BLOCK OPEN** Reactor Bldg to Torus Vacuum Breaker valves:
   - V-26-15 [ ]
   - V-26-17 [ ]
4. **COMPLETE** Attachment 312.9-6, Reactor Building to Torus Vacuum Breaker Control Sheet. [ ]

7.3.7 WHEN Primary Containment is required,

THEN **PURGE** the Torus as follows:

1. **VERIFY** temporary modification is installed in accordance with Attachment 312.9-8. [ ]
2. **VERIFY** Breathing Air System is in service in accordance with Procedure 334.1. [ ]
3. **CONFIRM** closed Drywell Vent and Bypass valves:
   - V-27-1 [ ]
   - V-27-2 [ ]
   - V-23-21 [ ]
   - V-23-22 [ ]
4. **OPEN** Torus Vent valves:
   - V-28-17 [ ]
   - V-28-18 [ ]

5. **CONFIRM** closed Drywell N_2 Purge valves (Panel 12XR):
   - V-23-13 [ ]
   - V-23-14 [ ]
6. **OPEN** Torus N_2 Purge valves (Panel 12XR):
   - V-23-15 [ ]
   - V-23-16 [ ]
7. **CLOSE** valve V-23-357. [ ]
8. **CLOSE** valve V-23-224. [ ]
9. **OPEN** valve V-23-356. [ ]
10. NOTE

    Torus and Drywell pressure must be monitored when breathing air is being supplied to the Torus. This ensures a positive DP is maintained between Drywell and Torus to prevent opening the Torus to Drywell vacuum breakers.

    THROTTLE open valve V-44-284. [ ]
11. IF Torus pressure increases to 0.5 psi greater than Drywell pressure,

    THEN **THROTTLE** closed valve V-44-284 until Torus pressure decreases below Drywell pressure. [ ]
12. **PURGE** the Torus in this manner until desired oxygen level is reached. [ ]

13. **CLOSE** valve V-44-284. [ ]

14. **CLOSE** valve V-23-356. [ ]

15. **OPEN** valve V-23-224. [ ]

16. **OPEN** valve V-23-357. [ ]

17. **CLOSE** Torus N_2 Purge valves (Panel 12XR):

    - V-23-15 [ ]
    - V-23-16 [ ]

18. **CLOSE** Torus Vent valves:

    - V-28-17 [ ]
    - V-28-18 [ ]

7.3.8 WHEN the atmosphere is acceptable for Drywell entry as monitored by portable O_2 sampling equipment,

THEN **MAINTAIN** an air purge at all times while the Drywell and Torus are open for entry by the following valves being OPEN (Panels 11F and 11R):

- MAIN SUPPLY HEADER VALVES TO DW V-28-42 and V-28-43
- DW PURGE V-27-3
- DW PURGE V-27-4
- DW VENT V-27-1
- DW VENT V-27-2

7.3.9 WHEN the MODE switch is **no** longer in the RUN position,

THEN **PLACE** the DRYWELL VENT-PURGE INTERLOCK BYPASS switch in NORMAL position (Panel 12XR). [ ]

7.3.10 **MAINTAIN** Drywell and Torus ventilation in accordance with Procedure 233, Drywell Access and Control.

8.0 DRYWELL COOLER FAN OPERATION

8.1 Prerequisites

8.1.1 Reactor Building Closed Cooling Water System (RBCCW) is operating in accordance with Procedure 309.2. [ ]

8.1.2 480 Volt Electrical System is operating in accordance with Procedure 338. [ ]

8.1.3 MCC 1A23 and MCC 1B23 are energized in accordance with Attachment 312.9-1. [ ]

8.2 Precautions and Limitations

8.2.1 Four Drywell Recirculation Fans should be in operation at all times. If Drywell ventilation must be reduced during Reactor operation, closely monitor Drywell pressure (Panel 12XR) and adjust pressure in accordance with Procedure 312.11.

8.3 Instructions

8.3.1 **PLACE** the Drywell Recirculation Fans in operation as follows:

8.3.1.1 **OPEN** the following valves (Panel 1F/2F):

- CCW INLET ISOLATION V-5-147 [ ]
- CCW INLET ISOLATION V-5-167 [ ]
- DRYWELL CLG SHUT-OFF V-5-148 [ ]
- CCW OUTLET ISOLATION V-5-166 [ ]