FACILITY POST-EXAMINATION COMMENTS

DATED DECEMBER 13, 2004, AND JANUARY 6, 2005

FOR THE PERRY INITIAL EXAMINATION - NOV/DEC 2004

FENOC
FirstEnergy Nuclear Operating Company

Perry Nuclear Power Plant
10 Center Road
P.O. Box 97
Perry, Ohio 44081

December 13, 2004
PY-CEI/OIE-0628L

United States Nuclear Regulatory Commission
2443 Warrenville Road, STE 210
Lisle, Illinois 60532-4352

Attention: Mr. Dell R. McNeil
Division of Reactor Safety

Perry Nuclear Power Plant
Docket No. 50-440
NRC License Operator Exam for Class 03-01

Dear Mr. McNeil:

The Perry Nuclear Power Plant (PNPP) staff is respectfully requesting the Nuclear Regulatory Commission (NRC) staff to review Attachment 1 regarding specific issues that have been identified with select operator license exam questions and answers used in the most recent PNPP exam for Class 03-01.

Also, the PNPP staff requests that the operator license exam grades for Class 03-01 be officially released.

Please contact me at (440) 280-5056 if you have questions or require additional information.

Sincerely,

J. Duffield
Perry Training Section Manager

DEC 15 2004

Question no. 1 –
2 correct answers. Answer A is also correct, the A pump could be downshifted to minimize loop flow mismatch.
Reference - Tech Spec 3.4.1 loop flow mismatch
Helps Hayes, Lesiak, Pry, Weeks

Question no. 2 –
2 correct answers. Answer A is also correct assuming all automatic actions occur. George Lesiak was not given the information that the bus EH12 stayed de-energized.
Helps Lesiak

Question no.10–
2 correct answers. Answer D is also correct because the radiation alarm requires entry into ONI-D17.
Reference ONI-D17
3.0 IMMEDIATE ACTIONS
3.1 EVACUATE the affected area
Helps Hetrick, Pry, Slack, Jones, Rainey, Weeks

Question no. 14 –
Toss out for Reactor Operators. This is beyond the scope of what is required knowledge.
Helps Jones, Rainey, Evans

Question no.27–
2 correct answers. Answer A is also correct per Tech Spec 3.6.3.2 Bases, which states one train can handle hydrogen generated from 75% of the fuel clad.
Reference TS 3.6.3.2
Helps Lesiak, Weeks, Rainey

Question 34
2 correct answers. Answer D is also correct because both answers are parts of performing SPI 1.8
Reference: PEI-SPI 1.8
Helps Evans

Question 45
2 correct answers. Answer A is also correct because Drywell pressure has an effect on suppression pool level. This changes the pressure above SRV riser. Therefore, SRV temperature will be a range dependent upon Drywell pressure.
Helps Evans, Hayes

Question no. 55
2 correct answers. Answer C is also correct because there will be a dp developed and the rod may possibly move due to the differences in surface areas of p under and p over.
Reference GEK – says possible cause can be inoperable directional control valve
Helps Rainey

Question no. 58
2 corrrect answers. Answer C is also correct because at a suppression pool temperature of 150° F, RHR A can be placed in suppression pool cooling.
Reference - SPI 3.2 directs the following:
3.7.3.1 **OPEN** RHR A(B) TEST VALVE TO SUPR POOL
E12-F024A(B).
Helps Weeks

Question no. 60
2 correct answers. Answer D could also be correct because it depends on the speed of the MSIV closure. If slow enough, Answer D would also be correct.
Helps Hayes, Jones, Kloosterman, Rainey, Lesiak, Jardine, Hetrick, Weeks

Question no. 65
2 correct answers. Answer B is also correct because the surveillance covers 2 Tech Specs - 3.9.1.1 and 3.9.2.2, making Answer B and C correct. The question states the surveillance fails not just the one rod out interlock.
Helps Jones, Weeks, Hetrick, Hayes, Pry

Question no. 66
Throw out. These are certification requirements they receive prior to their first watch. No INPO ACAD requirements require this to be taught prior to receiving a license.
Helps Rainey, Jones, Evans, Weeks, Hayes, Pry, Lesiak

Question 73
2 correct answers. Answer A is correct because the alarm response mode shall be given at the next brief. The answer does not state when the announcement should be made.
Helps Pry

Question 74
2 correct answers. Answer C is correct because all positions on a shift crew can be fire brigade members. There is no reference that disqualifies any position.
Helps Jones

Question 75
2 correct answers. Answer B is correct as stated in PAP-0528 as it directs Subsequent actions should be performed in order along with the site expectation that should is considered shall. The old procedure used to say the steps may be performed out of order. This statement has been removed.
Helps Lesiak, Pry, Slack, Jones, Rainey, Weeks

Question 79
2 correct answers. Answer B is correct because minimum steam cooling water level with injection meets the definition of adequate core cooling.
Reference: PEI Bases Definition of Adequate Core Cooling
Helps Pry, Hetrick

Question 86
2 correct answers. Answer D is correct because the pump may be required for adequate core cooling and should not be completely removed from service until it is known whether it is needed or not.
Helps Hayes

Question 92
Throw out. The only correct answer is non-conservative and would not be in the best interest of the health and safety of the public.

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Vice President-Nuclear

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January 6, 2005
PY-CEI/OIE-0630L

United States Nuclear Regulatory Commission
2443 Warrenville Road, STE 210
Lisle, Illinois 60532-4352

Attention: Mr. Dell R. McNeil
Division of Reactor Safety

Perry Nuclear Power Plant
Docket No. 50-440
NRC License Operator Exam for Class 03-01

Dear Mr. McNeil:

By letter dated December 14, 2004, the Perry Nuclear Power Plant (PNPP) requested the Nuclear Regulatory Commission (NRC) staff review specific issues with select operator license exam questions and answers used in the most recent PNPP exam for Class 03-01. In light of subsequent discussions concerning our letter, we are resubmitting our request with changes and additional supporting information.

As in our first letter, the PNPP staff also requests that the operator license exam grades for Class 03-01 be officially released.

If you have any questions or require additional information, please contact John Duffield, Manager Perry Training Section, at (440) 280-5056.

Sincerely,

Richard Anderson

Attachment

1. Perry Initial License Exam Class 03-01

cc: Document Control Desk
NRC Project Manager
NRC Resident Inspector

JAN 10 2005

Perry Initial License Exam
Class 03-01

Note: NRC Answers are bolded. Proposed alternate answers are bolded and italicized.

QUESTION 001

Based upon further review by the utility, the appeal for this question is being withdrawn.

QUESTION 002

Given the following initial plant conditions:
- Mode 3 with a plant cooldown in progress following an extended high power run.
- RHR loop "B" is in Shutdown Cooling (SDC) mode
- Coolant temperature is 335°F
- RPV pressure is 110 psig

Select the statement that describes the effect on the SDC Suction Isolation Inboard and Outboard Valves (1 E12-F009 and 1E12-F008) if Bus EH12 (4.16 KV) trips:

a) ***1E12-F008 and 1E12-F009 will shut.***

b) 1E12-F008 and 1E12-F009 will NOT shut.

c) 1E12-F008 will shut, 1E12-F009 will NOT shut.

d) **1E12-F008 will NOT shut, 1 E12-F009 will shut.**

Comment:
2 correct answers – Mr. Lesiak indicated he did not receive information supplied by the proctor that bus EH12 stayed de-energized and did not energize on the diesel supply. Answer A is also correct assuming the diesel re-energizes the bus and power is restored to the 1E12F009 valve.

Reference: ONI-R22-1, Loss of an essential 4160 volt bus
Drawing 208-013 Sh 12, Nuclear Steam Shutoff System

Licensee's Position:

The utility believes that there are two correct answers.

QUESTION 010

Based upon further review by the Utility, the appeal for this question is being withdrawn. Condition report 04-06852 was written to ensure the wording in the two procedures is made consistent.

PERRY NUCLEAR POWER PLANT		Instruction Number: ONI-R22-1
Title: LOSS OF AN ESSENTIAL AND/OR A STUB 4.16KV BUS	Use Category: In Field Reference	
	Revision: 5	Page 1 of 9

Q 2 ⟹ **LOSS OF AN ESSENTIAL AND/OR A STUB 4.16KV BUS**

Effective Date: 9-3-04

Preparer: Tracey L. Rose / 8-20-04
Date

Auxiliary and Startup Power Section, Long Response Benchboard, 1H13-P870

- INTERBUS XFMR LH-1-A LOCKOUT RELAY

1.2 Parameters

The changes in plant parameters vary depending upon the bus lost, the reactor power level at the time of bus failure, and the components presently being supplied from the bus.

2.0 AUTOMATIC ACTIONS

2.1 Emergency Diesel Generator for the de-energized EH Bus receives an auto start signal.

2.2 Standby units start as operating equipment is lost.

2.3 **IF** EH11 **AND** EH12 are de-energized
THEN the following start/reposition when power is regained:

- MCC, SWGR, and Misc. Elect Equip Area HVAC System, M23/M24
- Control Room HVAC and Emergency Recirculation System, M25/M26 Q2 ⇨
- Makeup Water Pretreatment System, P20
- Service Water System, P41
- Emergency Closed Cooling System, P42
- Nuclear Closed Cooling System, P43
- Emergency Service Water System, P45
- Control Complex Chilled Water System, P47

2.4 An NSSSS isolation signal is generated to Div 1 (Div 2) components due to de-energization of NSSSS relays when Bus EH11(EH12) is lost.

PERRY NUCLEAR POWER PLANT	Instruction Number: ONI-R22-1	
Title: LOSS OF AN ESSENTIAL AND/OR A STUB 4.16KV BUS	Use Category: In Field Reference	
	Revision: 5	Page 5 of 9

3.0 IMMEDIATE ACTIONS

NA 3.1 ❑ **IF** the loss of an essential 4.16KV Bus was due to a loss of offsite power, **THEN REFER TO** ONI-R10, Loss of AC Power.

4.0 SUPPLEMENTAL ACTIONS

> NOTE
>
> Protective relays and flags should be recorded and the cause of the trip should be determined prior to resetting tripped breakers.

4.1 **REFER TO** the following instructions concurrently with this instruction:

- ❑ ONI-C11-1, Inability to Move Control Rods
- Q 2 ❑ ONI-E12-2, Loss of Decay Heat Removal.
- ❑ ONI-P41, Loss of Service Water.
- ❑ ONI-P43, Loss of Nuclear Closed Cooling.
- ❑ ONI-B21-4, Isolation Restoration.

❑ 4.2 **REFER TO** EPI-A1 and **DETERMINE** if an Emergency Action Levels have been exceeded.

PERRY NUCLEAR POWER PLANT	Instruction Number: ONI-R22-1	
Title: LOSS OF AN ESSENTIAL AND/OR A STUB 4.16KV BUS	Use Category: In Field Reference	
	Revision: 5	Page 6 of 9

Q2

NOTE

Divisional valves receiving an isolation signal from the NSSS System will reposition to the isolated position as soon as power is restored.

NA 4.3

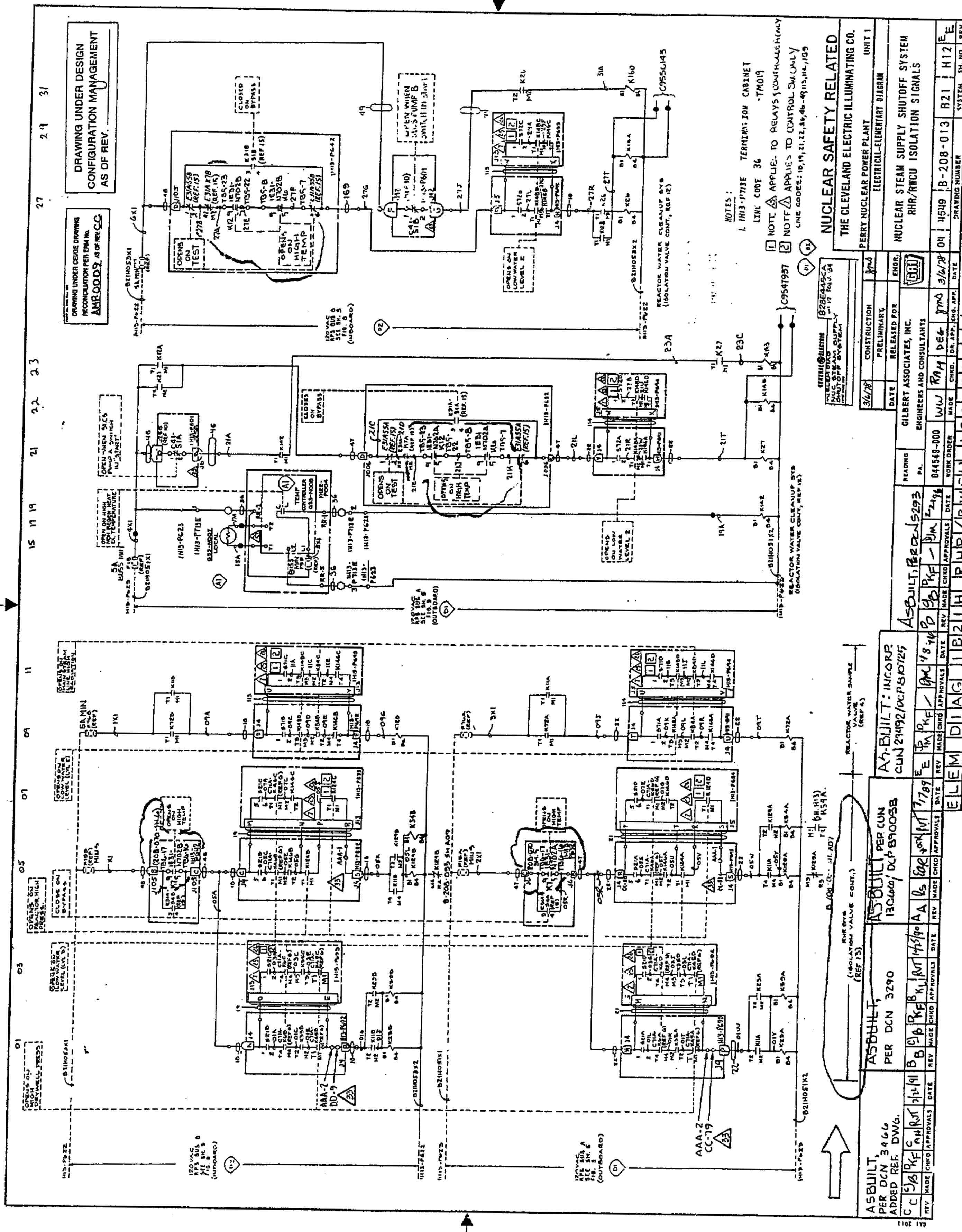
An EH Bus is de-energized
The Diesel Generator failed to start
Interbus Transformer LH-2-A is available
LH-2-A is the preferred option to restore power to the bus quickly.
THEN PERFORM the following:

- ❑ 4.3.1.a **VERIFY** the PREFERRED SOURCE BRKR is open — EH1114 EH1212 EH1303
- ❑ 4.3.1.b **CLOSE** the ALTN PREFERRED SOURCE BRKR. — EH1115 EH1213 EH1302

NA 4.4

An EH Bus is de-energized
The Diesel Generator failed to start
Interbus Transformer LH-1-A is available
LH-1-A is the preferred option to restore power to the bus quickly.
THEN PERFORM the following:

- ❑ 4.4.1.a **VERIFY** the ALTN PREFERRED SOURCE BRKR is open. — EH1115 EH1213 EH1302
- ❑ 4.4.1.b **CLOSE** the PREFERRED SOURCE BRKR. — EH1114 EH1212 EH1303


DRAWING UNDER DESIGN CONFIGURATION MANAGEMENT AS OF REV.
NUCLEAR SAFETY RELATED
THE CLEVELAND ELECTRIC ILLUMINATING CO.
PERRY NUCLEAR POWER PLANT
UNIT 1
ELECTRICAL-ELEMENTARY DIAGRAM
NUCLEAR STEAM SUPPLY SHUTOFF SYSTEM
RHR/RWCU ISOLATION SIGNALS
GILBERT ASSOCIATES, INC.
ENGINEERS AND CONSULTANTS
B-208-013
B21
H12
ELEM DIAG IB21H RHR/RWCU ISOL SIGLS

Q2

QUESTION 014

Based upon further review by the Utility, the appeal for this question is being withdrawn. The initial request was to remove this question based on being beyond the JTA requirements for RO's. Feedback from the Lead Examiner indicates this was a 3.8 K/A requirement for the RO. Utility review of the K/A Catalog, assuming this was a knowledge under 230000 A4.14, makes this appeal basis invalid.

QUESTION 027

A LOCA has occurred resulting in significant Hydrogen generation. One division of Hydrogen Igniters is in operation and one Combustible Gas Mixing Compressor is operating. Both Hydrogen Recombiners are shutdown due to Hydrogen concentration exceeding 6% in containment. Hydrogen concentration is continuing to increase. Which one of the following statements best explains why Hydrogen concentration is continuing to increase?

a) ***Hydrogen generation has exceeded the operational capability of the one division of Hydrogen Igniters that are in service.***

b) **A continuing increase in hydrogen concentration is indicative of a steam inert or Oxygen starved environment.**

c) Hydrogen concentration will continue to increase until the Hydrogen Igniters reach their operating temperature which can take several hours.

d) The indicated increase must be due to a malfunction of the Hydrogen Analyzer since actual concentration cannot exceed 6% as long as the Hydrogen Igniters are in operation.

Comment:
2 correct answers – answer A could also be correct, Tech Spec Bases 3.6.3.2 states that "the H2 igniters are installed to accommodate the amount of hydrogen equivalent to that generated from the reaction of 75% of the fuel cladding with water". The question stem provides the information that only one train of H2 igniters is in operation and that there is "significant" H2 generation. No specifics are provided as to the actual amount of H2 generated, and ½ of the required igniters are not functioning. The trainee could infer that the potential exists that it has exceeded the capability of the single H2 igniter train in operation, before an inert environment has occurred.

Reference TS 3.6.3.2.bases

Licensee's Position:

The utility believes that there are two correct answers.

Attachment 1
PY-CEI/OIE-0630L
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B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.2 Primary Containment and Drywell Hydrogen Igniters

BASES

BACKGROUND

The primary containment and drywell hydrogen igniters are a part of the combustible gas control required by 10 CFR 50.44 (Ref. 1) and GDC 41, "Containment Atmosphere Cleanup" (Ref. 2), to reduce the hydrogen concentration in the primary containment following a degraded core accident. The hydrogen igniters ensure the combustion of hydrogen in a manner such that containment overpressure failure is prevented as a result of a postulated degraded core accident.

Q 27

10 CFR 50.44 (Ref. 1) requires boiling water reactor units with Mark III containments to install suitable hydrogen control systems. The hydrogen igniters are installed to accommodate an amount of hydrogen equivalent to that generated from the reaction of 75% of the fuel cladding with water. This requirement was placed on reactor units with Mark III containments because they were not designed for inerting and because of their low design pressure. Calculations indicate that if hydrogen equivalent to that generated from the reaction of 75% of the fuel cladding with water were to collect in primary containment, the resulting hydrogen concentration would be far above the lower flammability limit such that, without the hydrogen igniters, if the hydrogen were ignited from a random ignition source, the resulting hydrogen burn would seriously challenge the primary containment.

Q 27

The hydrogen igniters are based on the concept of controlled ignition using thermal igniters designed to be capable of functioning in a post accident environment, seismically supported and capable of actuation from the control room. Hydrogen igniters are distributed throughout the drywell and primary containment in which hydrogen could be released or to which it could flow in significant quantities. The hydrogen igniters are arranged in two independent divisions such that each containment region has two igniters, one from each division, controlled and powered redundantly so that ignition would occur in each region even if one division failed to energize. 96-109

(continued)

BASES

BACKGROUND (continued)

When the hydrogen igniters are energized they heat up to a surface temperature ≥ 1700°F. At this temperature, they ignite the hydrogen gas that is present in the airspace in the vicinity of the igniter. The hydrogen igniters depend on the dispersed location of the igniters so that local pockets of hydrogen at increased concentrations would burn before reaching a hydrogen concentration significantly higher than the lower flammability limit.

APPLICABLE SAFETY ANALYSES

The hydrogen igniters cause hydrogen in containment to burn in a controlled manner as it accumulates following a degraded core accident (Ref. 3). Burning occurs at the lower flammability concentration, where the resulting temperatures and pressures are relatively benign. Without the hydrogen igniters, hydrogen could build up to higher concentrations that could result in a violent reaction if ignited by a random ignition source after such a buildup.

Q 27

The hydrogen igniters are not included for mitigation of a Design Basis Accident (DBA) because an amount of hydrogen equivalent to that generated from the reaction of 75% of the fuel cladding with water is far in excess of the hydrogen calculated for the limiting DBA loss of coolant accident (LOCA). The hydrogen concentration resulting from a DBA can be maintained less than the flammability limit using the primary containment hydrogen recombiners in conjunction with the Combustible Gas Mixing System. However, the hydrogen igniters have been shown by probabilistic risk analysis to be a significant contributor to limiting the severity of accident sequences that are commonly found to dominate risk for units with Mark III containment.

The hydrogen igniters are considered to be risk significant in accordance with the NRC Policy Statement.

LCO

Two divisions of primary containment and drywell hydrogen igniters must be OPERABLE, each with 90% or more of the igniters OPERABLE (i.e., no more than five igniters inoperable.)

(continued)

LCO (continued)

This ensures operation of at least one hydrogen igniter division, with adequate coverage of the primary containment and drywell, in the event of a worst case single active failure. This will ensure that the hydrogen concentration remains near 4.0 v/o.

APPLICABILITY

In MODES 1 and 2, the hydrogen igniter is required to control hydrogen concentration to near the flammability limit of 4.0 v/o following a degraded core event that would generate hydrogen in amounts equivalent to a metal water reaction of 75% of the core cladding. The control of hydrogen concentration prevents overpressurization of the primary containment. The event that could generate hydrogen in quantities sufficiently high enough to exceed the flammability limit is limited to MODES 1 and 2.

In MODE 3, both the hydrogen production rate and the total hydrogen produced after a degraded core accident would be less than that calculated for the DBA LOCA. Also, because of the limited time in this MODE, the probability of an accident requiring the hydrogen igniter is low. Therefore, the hydrogen igniter is not required in MODE 3.

In MODES 4 and 5, the probability and consequences of a degraded core accident are reduced due to the pressure and temperature limitations. Therefore, the hydrogen igniters are not required to be OPERABLE in MODES 4 and 5 to control hydrogen.

ACTIONS

A.1

Q27

With one hydrogen igniter division inoperable, the inoperable division must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE hydrogen igniter division is adequate to perform the hydrogen burn function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced hydrogen control capability. The 30 day Completion Time is based on the low probability of the occurrence of a degraded core event that would generate hydrogen in amounts equivalent to a metal water reaction of 75% of the core cladding, the amount of time available after the event for operator action to prevent hydrogen

(continued)

 96-109

QUESTION 034

The plant was operating at 100% reactor power when the plant experienced an earthquake. A medium break LOCA occurred and RPV Level 2 was reached. All ECCS systems responded correctly. RPV level is currently 180 inches and slowly increasing. The reactor failed to scram and all efforts to manually insert control rods have failed. Standby liquid control has failed to correctly initiate and shut down the reactor (failed SQUIBB valves). The Unit Supervisor has decided to initiate Alternate Boron Injection (ABI) in accordance with PEI-SPI 1.8. What needs to be done in order to successfully initiate Alternate Boron Injection?

a) **Secure HPCS.**

b) Close E22-F004 (HPCS Injection Valve)

c) Secure both SLC pumps

d) ***Connect a low pressure hose from the SLC storage tank to the suction of the ABI pump; start the ABI pump, open the ABI pump discharge valve.***

Comment:
2 correct answers – answer D is also correct. Both answers are parts of performing SPI 1.8 Verbal discussions with the lead examiner indicates that there is no correct answer and that both of the above are partial answers. The question will be removed from the test. The utility concurs with this decision.

Reference: PEI-SPI 1.8

Licensee's Position:

The utility agrees with the NRC position on no correct answers.

QUESTION 045

Based upon further review by the Utility, the appeal for this question is being withdrawn.

QUESTION 055

While attempting to insert a control rod, the operator depresses the INSERT pushbutton and observes the following:

- No rod motion
- CRD DRIVE WATER HEADER FLOW at 0 gpm
- CRD COOLING WATER FLOW at 60 gpm

Which ONE of the following is the possible cause of these indications?

a) CRD Flow Control Valve failed closed.

b) Associated drive water stabilizing valves failed closed.

c) ***Associated Insert Exhaust Directional Control Valve (DCV 121) failed closed.***

d) **Associated Insert Drive Directional Control Valve (DCV 123) failed closed.**

Comment:
The two correct answers was based upon the fact that there may be no delta p developed without the exhaust valve being open. Although the rod may move due to the differences in surface areas of p under and p over and leakage through the seals, the potential exists that no flow will be developed with the exhaust valve closed, as there would be no flow path. This would make answer C also correct.

Reference: SDM C11 (CRDM and CRDH)
GEK 75598B

Licensee's Position:

The utility believes there are two correct answers.

#55

A. In Figure 4-17, a waveform is illustrated of notch-out from position "24" with flow through valve 120 restricted to 0.5 gpm (1.89 ℓ/min) less than normal. Note that:

1. CRD notch-out operation is successful.

2. An increase in drive-down dP occurred.

3. The settle period is extended.

4. A slight loss of response occurred at the commencement of the CRD settle period.

B. In Figure 4-18, a waveform is illustrated of notch-out from position "24" with failure of valve 120 to actuate. Note that:

1. No notch-out CRD operation occurred.

2. Drive-down dP is increased.

3. A loss of response occurred at the commencement of the settle period.

4. No settle period is indicated.

Q55

4-76 DIRECTIONAL CONTROL VALVE 121. Oscilloscope waveform traces showing leakage and flow restriction at directional control valve 121 are obtained by applying notch-in and notch-out signals to the CRD from position "24" and obtaining a waveform trace photograph of the dP across the CRD position.

4-77 Leakage. Leakage of 1.5 gpm (5.7 ℓ/min) across valve 121 during a notch-out operation results in a drive-down dP decrease. Leakage in excess of 1.5 gpm (5.7 ℓ/min) may result in failure of the CRD to notch-out because of losses in drive-down pressure and pressure to unlock the CRD collet. Refer to Figures 4-19, 4-20, and 4-21. Compare these and the photograph obtained with reference Figure 4-6.

A. In Figure 4-19, a waveform is illustrated of notch-out from position "24" with 1.5 gpm (5.7 ℓ/min) leakage across valve 121. Note that:

1. The CRD notch-out is successful.

2. A decrease occurs in drive-down dP.

3. A slight gain occurs in settle dP.

4. Settle time is increased.

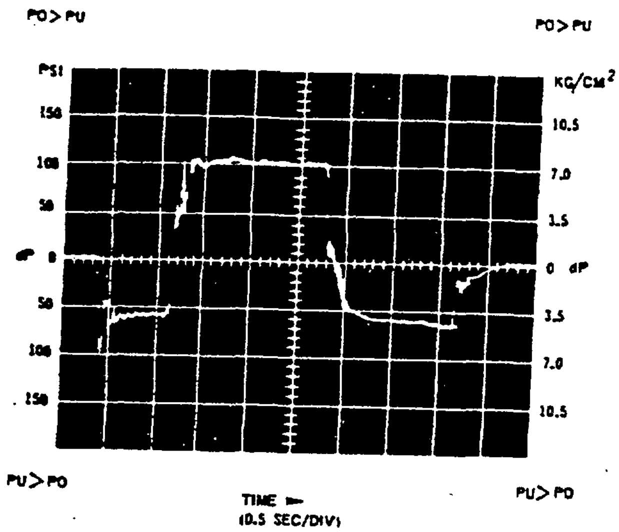


Figure 4-19. Waveform Trace: Notch-Out from Position 24 with 1.5 gpm (5.7 ℓ/min) Leakage Across Valve 121

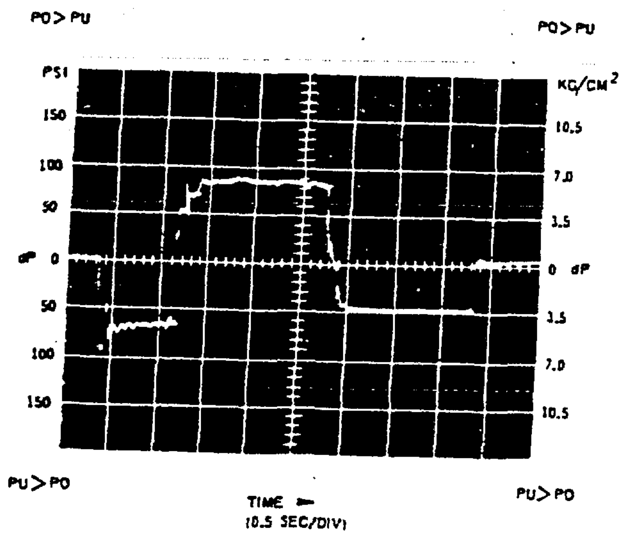


Figure 4-20. Waveform Trace: Notch-Out from Position 24 with 3 gpm (11.4 ℓ/min) Leakage Across Valve 121

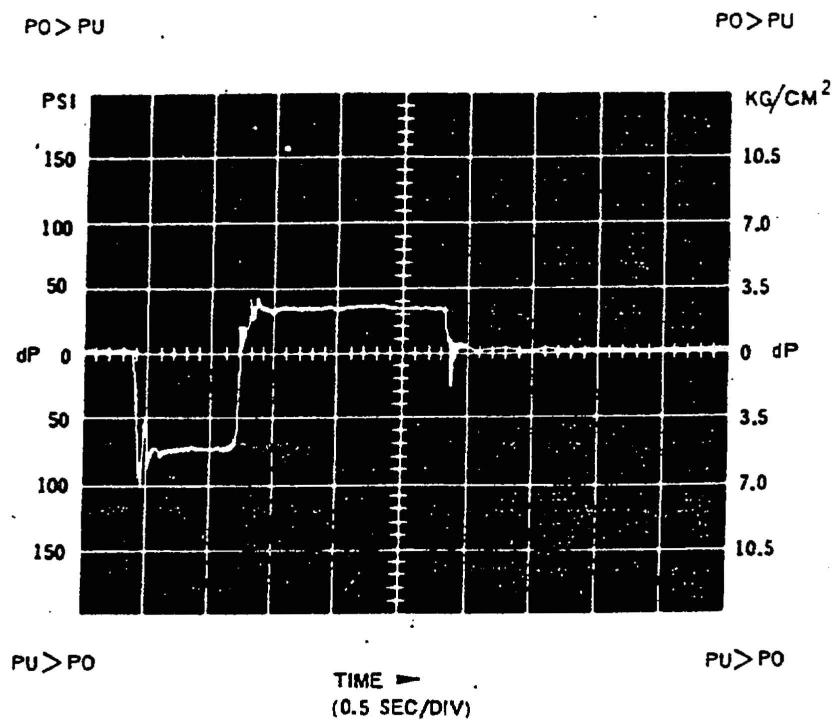


Figure 4-21. Waveform Trace: Notch-Out from Position 24 with Valve 121 Failed Full-Open

B. In Figure 4-20, a waveform is illustrated of notch-out from position "24" with 3 gpm (11.4 ℓ/min) leakage across valve 121. Note that:

1. The CRD notch-out is successful.

2. A loss in drive-down dP occurs.

3. Settle time is extended.

C. In Figure 4-21, a waveform is illutrated of notch-out from position "24" with valve 121 failed in the full-open position. Note that:

1. The CRD failed to notch-out.

2. A loss in drive-down dP occurs.

3. No settle period is indicated.

121

Q55 4-78 Flow Restriction. As restriction of flow through valve 121 increases during a notch-in sequence, the drive-in dP decreases. Settle and flow indications appear normal. Failure of valve 121 to actuate in response to a notch-in signal results in reversed driving dP (i.e., PO is greater than PU) and an extended settle period as well as decreased driving flow. Refer to Figures 4-22, 4-23, and 4-24. Compare these and the photograph obtained with reference Figure 4-5.

A. In Figure 4-22, a waveform is illustrated of notch-in position "24" with 1.4 gpm (5.3 ℓ/min) flow through valve 121. Note that:

1. CRD notch-in is successful.

2. A slight loss in drive-in dP occurs.

3. Overall the waveform trace appears normal (see reference Figure 4-5).

B. In Figure 4-23, a waveform is illustrated of notch-in with 0.7 gpm (2.65 ℓ/min) flow through valve 121. Note that:

1. The CRD notch-in is successful.

2. Drive-in dP is low.

3. Drive-in dP equals settle dP.

C. In Figure 4-24, a waveform is illustrated of notch-in from position "24" with valve 121 failed-closed. Note that:

1. CRD failed to notch-in.

2. Drive-in dP is erratic and reversed (i.e., PO greater than PU).

3. The settle period is extended.

4-79 DIRECTIONAL CONTROL VALVE 123. Measurement of dP at the HCU is not required for the detection of leakage through valve 123. Oscilloscope waveform traces showing flow restriction at valve 123 are obtained by applying notch-in signals to the CRD.

4-80 Leakage. Leakage through valve 123 can result in CRD drift-in when the CRD is at a latched position and no movement signal is applied. The CRD drift rate is dependent upon the rate of leakage through valve 123 (i.e., the greater the leakage through valve 123, the higher the CRD drift rate). Should valve 123 fail in the full-open position, the CRD will drift in at approximately its normal speed of 3 in./sec (76 mm/sec).

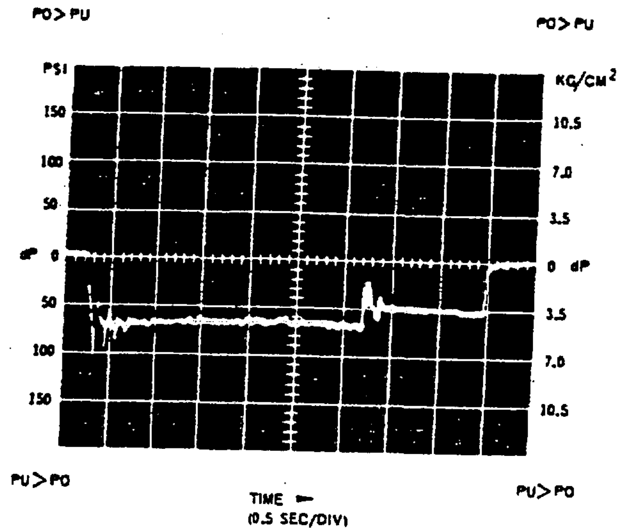


Figure 4-22. Waveform Trace: Notch-In from Position 24 with flow of 1.4 gpm (5.3 ℓ/min) through Valve 122

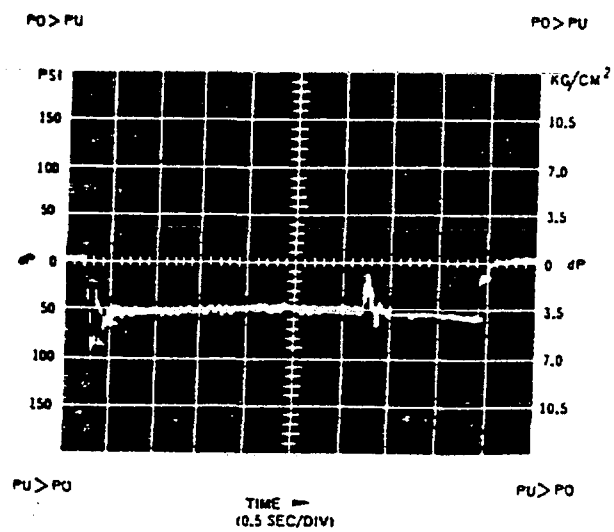


Figure 4-23. Waveform Trace: Notch-In from Position 24 with 0.7 gpm (2.65 ℓ/min) flow Through Valve 121

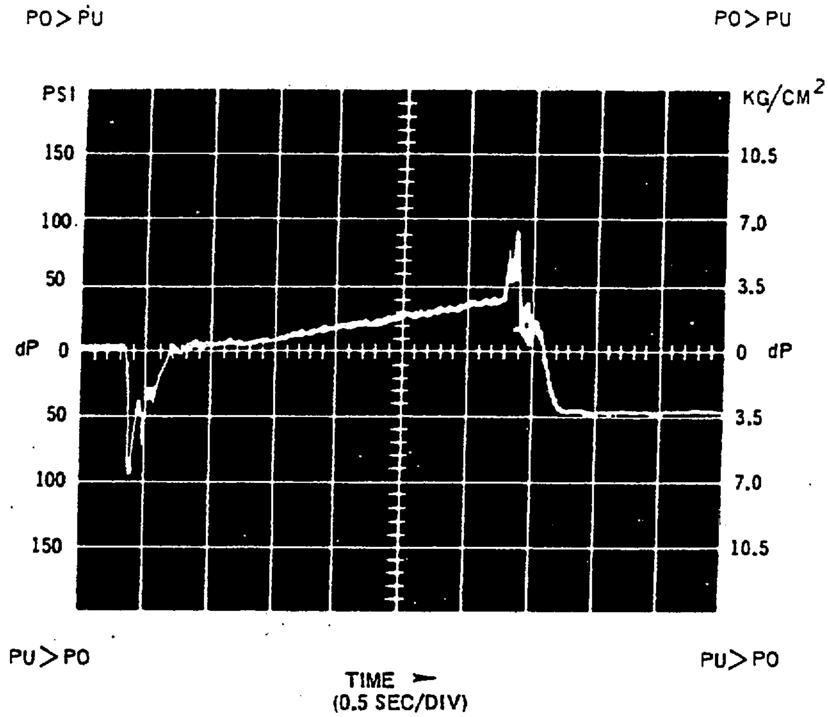


Figure 4-24. Waveform Trace: Notch-In from Position 24 with Valve 121 Failed-Closed

4-81 Flow Restriction. With flow through valve 123 restricted to 3 gpm (11.4 ℓ/min), the CRD fails to satisfactorily complete the notch-in operation. Similarly, no CRD movement is apparent with flow through valve 123 restricted to 0.5 gpm (1.89 ℓ/min). Refer to Figures 4-25 and 4-26. Compare these and the photograph obtained with reference Figure 4-6.

A. In Figure 4-25, a waveform is illustrated of notch-in from position "24" with flow through valve 123 restricted to a maximum of 3.2 gpm (12.1 ℓ/min). Note that:

1. The CRD failed to notch-in.

2. Drive-in dP is normal.

3. The settle period is extended.

should maintain drive temperatures below 250°F. The cooling water, see Figure 31, is supplied to the drive via the insert header and the insert port. The flow of the cooling water is upward through the strainer between the outer tube and thermal sleeve via a set screw plug orifice (23) located in the main flange. The flow continues upward through the outer screen and into the reactor. Normal cooling water header pressure is equal to reactor pressure plus 20 psi, and the normal cooling water flow rate through each drive mechanism is approximately .20 - .34 gpm. Utilize Figure 35 for a simplified flow path representation of this section.

b. Insert Function

On a rod insert signal, Figure 32, water from the drive header enters the insert port and is routed to the underside of the drive piston. Simultaneously, water from above the drive piston is exhausted through the flow ports (69) in the buffer shaft, down between the piston tube and indicator tube, and out the withdraw port.

Q55 ⇨

Unlocking the collet fingers is not required for CRDM insertion. The collet fingers are forced out of the locking notch as the index tube moves upward. The fingers grip the outside wall of the index tube and snap into the next lower locking notch for single notch insertion to hold the index tube in position. Utilize Figure 35 for a simplified flow path representation of this section.

c. Withdraw Functions

The collet locking mechanism requires a hydraulic pressure greater than reactor vessel pressure to unlock the fingers for CRDM

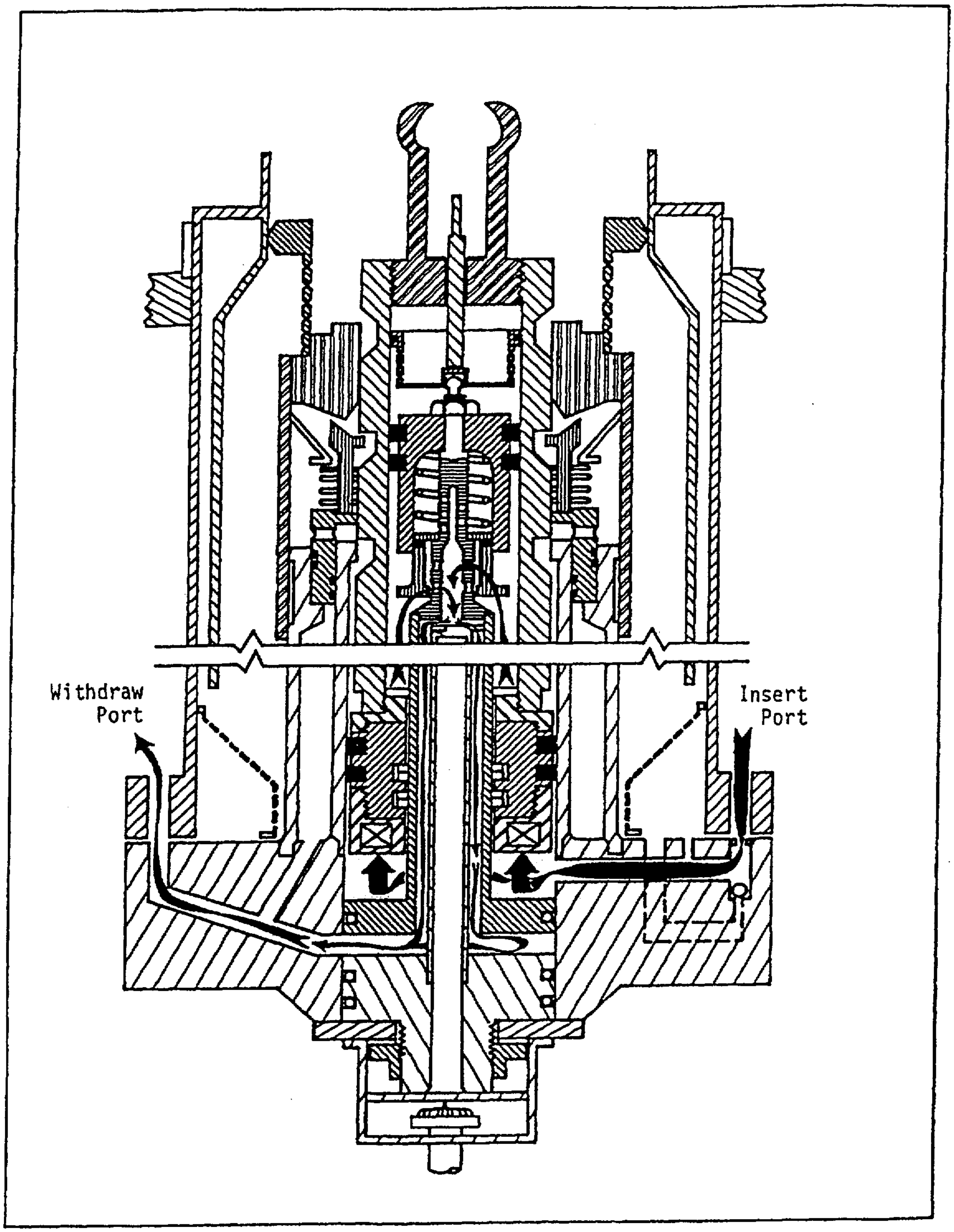


FIGURE C11(CRDM)-32
ROD INSERTION FLOW PATH

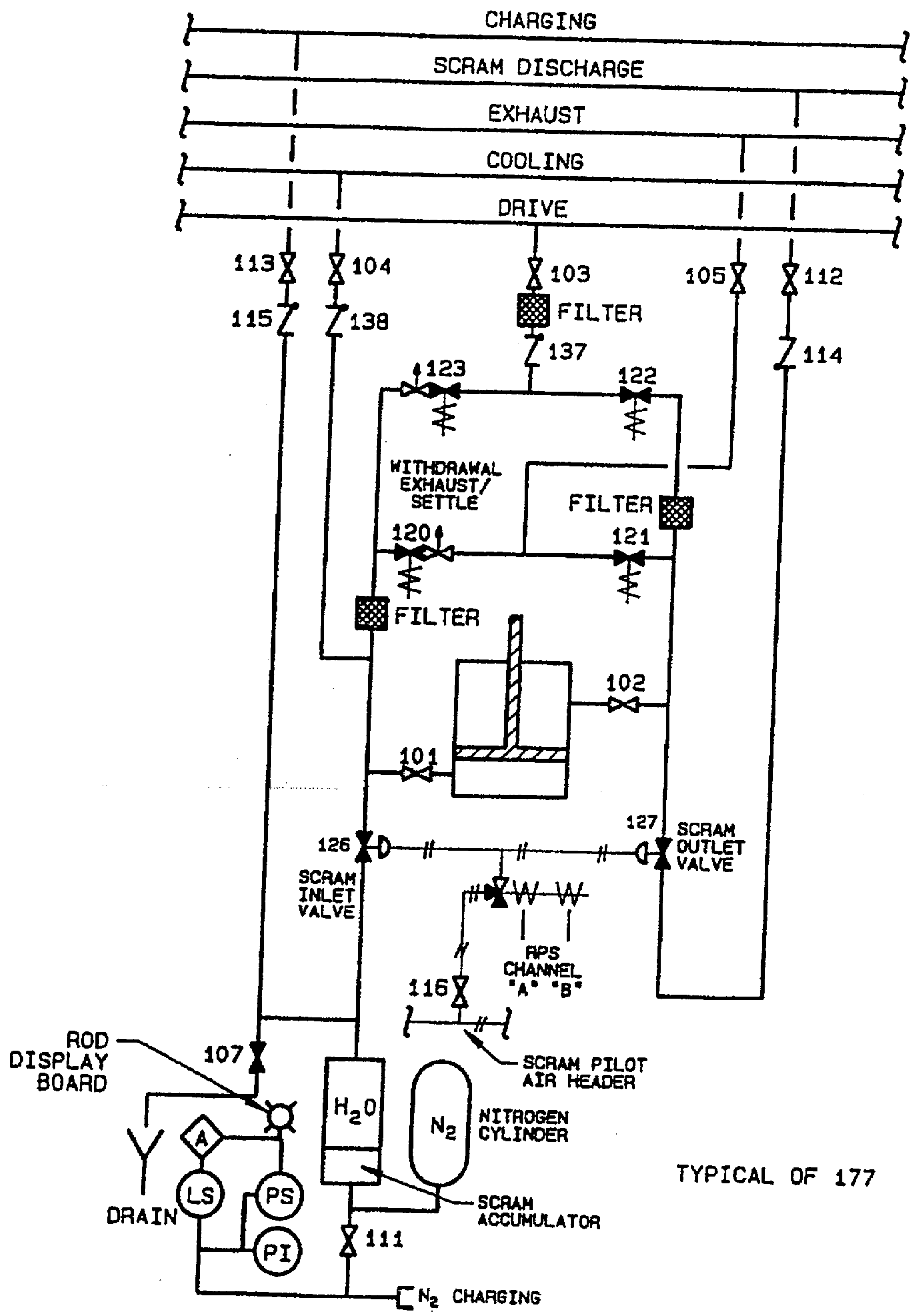


FIGURE C11(CRDH)-6
HYDRAULIC CONTROL UNIT PIPING DIAGRAM

QUESTION 058

A Main Steam line break (18 minutes ago) has resulted in the following plant conditions:

- Drywell pressure is 4.0 psig and decreasing slowly.
- Suppression Pool Temperature is 150° F,
- RPV water level is being maintained Main Steam lines with LPCS due to exceeding RPV Saturation Temperature in the Drywell.
- RHR B is operating in the Suppression Pool Cooling mode.
- RHR A is operating in the Containment Spray mode.
- Containment pressure is approaching 0 psig.

You have been directed to secure Containment Spray. While shutting the Containment Spray Shutoff Valve (F028A) you observe that the Minimum Flow Valve (F064A) did NOT open. should...

a) Reopen the Containment Spray Shutoff Valve (F028A)

b) Open the LPCI A Injection Valve (F042A)

c) ***Open the RHR A Test Valve to Supp. Pool (F024A)***

d) **Shutdown RHR Pump A**

Comment:
This question has two correct answers. Due to suppression pool temperature of 150 degrees F, if securing from containment spray per PEI-SPI 3.1, you may go in to suppression pool cooling on the RHR A Loop which would open the E12-F024A. In order to maintain the loop available, the SRO could direct performance of step 3.7.3.1. This would make answer C also correct, as opening the valve would prevent the pump from operating without minimum flow protection.

Reference: PEI-Bases
SPI 3.1

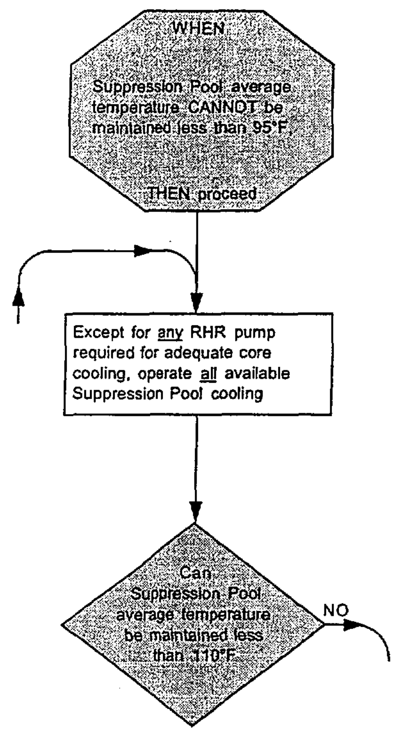
Licensee's Position:
The utility believes there are two correct answers

QUESTION 060

Based upon further review by the Utility, the appeal for this question is being withdrawn.

STEP:

Q58



DISCUSSION

When suppression pool temperature cannot be maintained below the most limiting suppression pool temperature LCO value (95°F), explicit instructions are given to operate all available methods of suppression pool cooling.

Maintaining adequate core cooling takes precedence over maintaining suppression pool temperature below the LCO value since catastrophic failure of the containment is not expected to occur at this temperature. In addition, further action is still available for reversing the increasing suppression pool temperature trend. Therefore, only if the operation of a RHR pump is not required to assure adequate core cooling is it permissible to use that pump for suppression pool cooling. This step however, does permit alternating the use of RHR pumps between the RPV injection mode and suppression pool cooling modes, as the need for each occurs, and so long as adequate core cooling can be maintained.

The Cleveland Electric Illuminating Company

PERRY OPERATIONS MANUAL

Plant Emergency Instruction

Q58 TITLE: SPECIAL PLANT INSTRUCTION 3.1

CONTAINMENT SPRAY OPERATION

REVISION: 0 EFFECTIVE DATE: 8-19-94

PREPARED: PEI Improvement Team 8-16-94
/ Date

EFFECTIVE PIC's

PIC No.	Type of Change	Effective Date

PEI-SPI 3.1 Containment Spray Operation

ENTRY CONDITIONS

This instruction is entered when Containment pressure or hydrogen concentration necessitate spraying of Containment, or when Containment sprays are to be terminated.

SCOPE

This instruction provides the necessary actions to manually initiate Containment sprays both before and after the RHR Containment Spray Loop has been used to vent Containment. The high Drywell pressure interlock is bypassed, if necessary, to allow spray initiation. Steps are also provided to realign Containment Spray to RPV injection or Suppression Pool Cooling. RPV injection may be routed inside or outside the shroud.

NECESSARY EQUIPMENT

Control Room PEI-SPI File Cabinet:
- four PEI-SPI keys

CC 599′ D/01, OSC PEI File Cabinet:
- one green locking tab

IB 599′ K/05:
- one 12 ft ladder

LOCATION OF REQUIRED LOCAL ACTIONS

AX 599′, above the RHR A(B) HX Room door:
- C/07(C/03), RHR A(B) FPCC Supplement Cooling Discharge Vlv 1E12-F099A(B)

(CONTINUED ON NEXT PAGE)

ACTIONS

1.0 **IF** RHR Containment Spray Loop A(B) is **NOT** lined up to vent Containment,
THEN INITIATE Containment Spray Loop A(B) as follows:

1.1 **IF** a high Drywell pressure LOCA signal is present,
THEN PROCEED TO Step 1.3 of this instruction.

1.2 **AT** H13-P629(P618),
PLACE CNTMT SPRAY A(B) HI DW PRESS BYP E12A-S75(S76) keylock switch in BYPASS.

> NOTE
>
> RHR Loop B Containment Spray manual initiation pushbutton must be depressed for at least 35 seconds to allow the signal to seal in.

1.3 **ARM** and **DEPRESS** CNTMT SPRAY A(B) MANUAL INITIATION E12A-S63A(B) pushbutton.

1.4 **VERIFY** RHR PUMP A(B) E12-C002A(B) is running.

1.5 **VERIFY** ESW PUMP A(B) P45-C001A(B) is running.

1.6 **VERIFY** ECC PUMP A(B) P42-C001A(B) is running.

1.7 **VERIFY** the following valves are open:

- CNTMT SPRAY A(B) FIRST SHUTOFF E12-F028A(B)
- CNTMT SPRAY A(B) SECOND SHUTOFF E12-F537A(B)

(CONTINUED ON NEXT PAGE)

NOTE
RHR A(B) HX'S BYPASS VALVE E12-F048A(B) will not close within ten minutes after a LOCA initiation signal.

NOTE
RHR A(B) HX'S BYPASS VALVE E12-F048A(B) will only automatically close if RHR A(B) HX'S INLET VALVE E12-F047A(B) and RHR A(B) HX'S OUTLET VALVE E12-F003A(B) are open.

1.8 **VERIFY** the following valves are closed:

- LPCI A(B) INJECTION VALVE E12-F042A(B)
- RHR A(B) TEST VALVE TO SUPR POOL E12-F024A(B)
- RHR A(B) HX'S BYPASS VALVE E12-F048A(B)
- SHUTDOWN COOLING A(B) TO FDW SHUTOFF E12-F053A(B)

(CONTINUED ON NEXT PAGE)

PEI-SPI 3.1 Containment Spray Operation (Continued)

CAUTION

System realignment other than as directed in the following step may result in water hammer severe enough to cause pressure boundary failure and subsequent uncontrolled release to the environment.

2.0 **IF** RHR Containment Spray Loop A(B) is lined up to vent Containment **OR** Containment is currently being vented via RHR Containment Spray Loop A(B),
THEN COMMENCE Containment Spray with RHR Loop A(B) as follows:

2.1 **IF** Containment is currently being vented via Containment Spray Loop A(B),
THEN CLOSE CNTMT SPRAY A(B) FIRST SHUTOFF E12-F028A(B) to secure venting.

2.2 **FILL** the drained RHR A(B) piping as follows:

> NOTE
>
> RHR A(B) HX'S OUTLET VALVE E12-F003A(B) is throttled open to allow the water leg pump to fill up the drained portion of the RHR header.

2.2.1 **THROTTLE** open RHR A(B) HX'S OUTLET √VALVE E12-F003A(B) to obtain 4-6% open.

2.2.2 **AT** AX 599' C/07(C/03), above RHR A(B) HX Room door, **CLOSE** and **LOCK** RHR A(B) FPCC Supplement Cooling Discharge Vlv 1E12-F099A(B).

2.2.3 **VERIFY** the following valves are open:

- CNTMT SPRAY A(B) FIRST SHUTOFF E12-F028A(B)
- CNTMT SPRAY A(B) SECOND SHUTOFF E12-F537A(B)

(CONTINUED ON NEXT PAGE)

PEI-SPI 3.1 Containment Spray Operation (Continued)

2.2.4 **VERIFY** the following valves are closed:

- LPCI A(B) INJECTION VALVE E12-F042A(B)
- RHR A(B) HX'S BYPASS VALVE E12-F048A(B)
- RHR A(B) HX'S INLET VALVE E12-F047A(B)

2.2.5 **VERIFY** ESW PUMP A(B) P45-C001A(B) is running.

2.2.6 **VERIFY** ECC PUMP A(B) P42-COO1A(B) is running.

2.2.7 **START** RHR PUMP A(B) E12-C002A(B).

2.2.8 **OPEN** RHR A(B) HX'S INLET VALVE E12-F047A(B).

2.2.9 **WHEN** flow is present as indicated on RHR A(B) PUMP FLOW E12-R603A(B),
THEN **THROTTLE** RHR A(B) HX'S OUTLET VALVE E12-F003A(B) slowly to obtain a flow rate of 1000-1500 gpm.

2.2.10 **WHEN** approximately four minutes have passed,
THEN **OPEN** RHR A(B) HX'S OUTLET VALVE E12-F003A(B).

(CONTINUED ON NEXT PAGE)

Q58 PEI-SPI 3.1 Containment Spray Operation (Continued)

3.0 **TERMINATE** RHR Containment Spray Loop A(B) as follows:

> NOTE
>
> LPCI A(B) INJECTION VALVE E12-F042A(B) control switch is overridden closed before resetting Containment Spray logic with a LPCI initiation signal present to prevent uncontrolled LPCI injection into the RPV.

3.1 **IF** LPCI A(B) initiation signal is present,
THEN TAKE LPCI A(B) INJECTION VALVE E12-F042A(B) control switch to CLOSE to obtain the amber override light.

3.2 **PLACE** CNTMT SPRAY A(B) MANUAL INITIATION E12A-S63A(B) pushbutton collar in DISARM.

3.3 **DEPRESS** CNTMT SPRAY A(B) SEAL IN RESET E12A-S64A(B) pushbutton to reset the Containment Spray initiation logic.

Q58 3.4 **IF** Combustible Gas Mixing System A(B) is **NOT** running,
THEN CLOSE CNTMT SPRAY A(B) FIRST SHUTOFF E12-F028A(B). (No Minimum Flow)

3.5 **CLOSE** CNTMT SPRAY A(B) SECOND SHUTOFF E12-F537A(B).

3.6 **IF** directed to inject into the RPV,
THEN COMMENCE injection with RHR A(B) Pump as follows:

3.6.1 **IF** directed to inject outside the shroud,
THEN INJECT as follows:

3.6.1.1 **AT** H13-P629(P618),
PLACE RHR ISOL BYPASS E12-F053A(B) keylock switch in BYPASS.

3.6.1.2 **OPEN** SHUTDOWN COOLING A(B) TO FDW SHUTOFF E12-F053A(B).

3.6.2 **IF** directed to inject inside the shroud,
THEN OPEN LPCI A(B) INJECTION VALVE E12-F042A(B).

(CONTINUED ON NEXT PAGE)

3.7 **IF** directed to place RHR A(B) in Suppression Pool Cooling, **THEN COMMENCE** Suppression Pool Cooling as follows:

NOTE

RHR A(B) HX'S BYPASS VALVE E12-F048A(B) and RHR A(B) HX'S OUTLET VALVE E12-F003A(B) will not close within ten minutes after a LOCA initiation signal.

3.7.1 **THROTTLE** RHR A(B) HX'S OUTLET VALVE E12-F003A(B) to obtain 60-65% open.

3.7.2 **VERIFY** RHR A(B) HX'S BYPASS VALVE E12-F048A(B) is closed.

(CONTINUED ON NEXT PAGE)

PEI-SPI 3.1 Containment Spray Operation (Continued)

CAUTION

Operating RHR A in Suppression Pool Cooling with LPCS in minimum flow may result in loss of flow for the LPCS Pump.

3.7.3 **IF** Combustible Gas Mixing System A(B) is **NOT** running,
THEN **THROTTLE** RHR flow as follows:

Q58

3.7.3.1 **OPEN** RHR A(B) TEST VALVE TO SUPR POOL E12-F024A(B).

3.7.3.2 **THROTTLE** open RHR A(B) HX'S OUTLET VALVE E12-F003A(B) to obtain 7100-7300 gpm.

3.7.4 **IF** Combustible Gas Mixing System A(B) is running,
THEN **THROTTLE** RHR flow as follows:

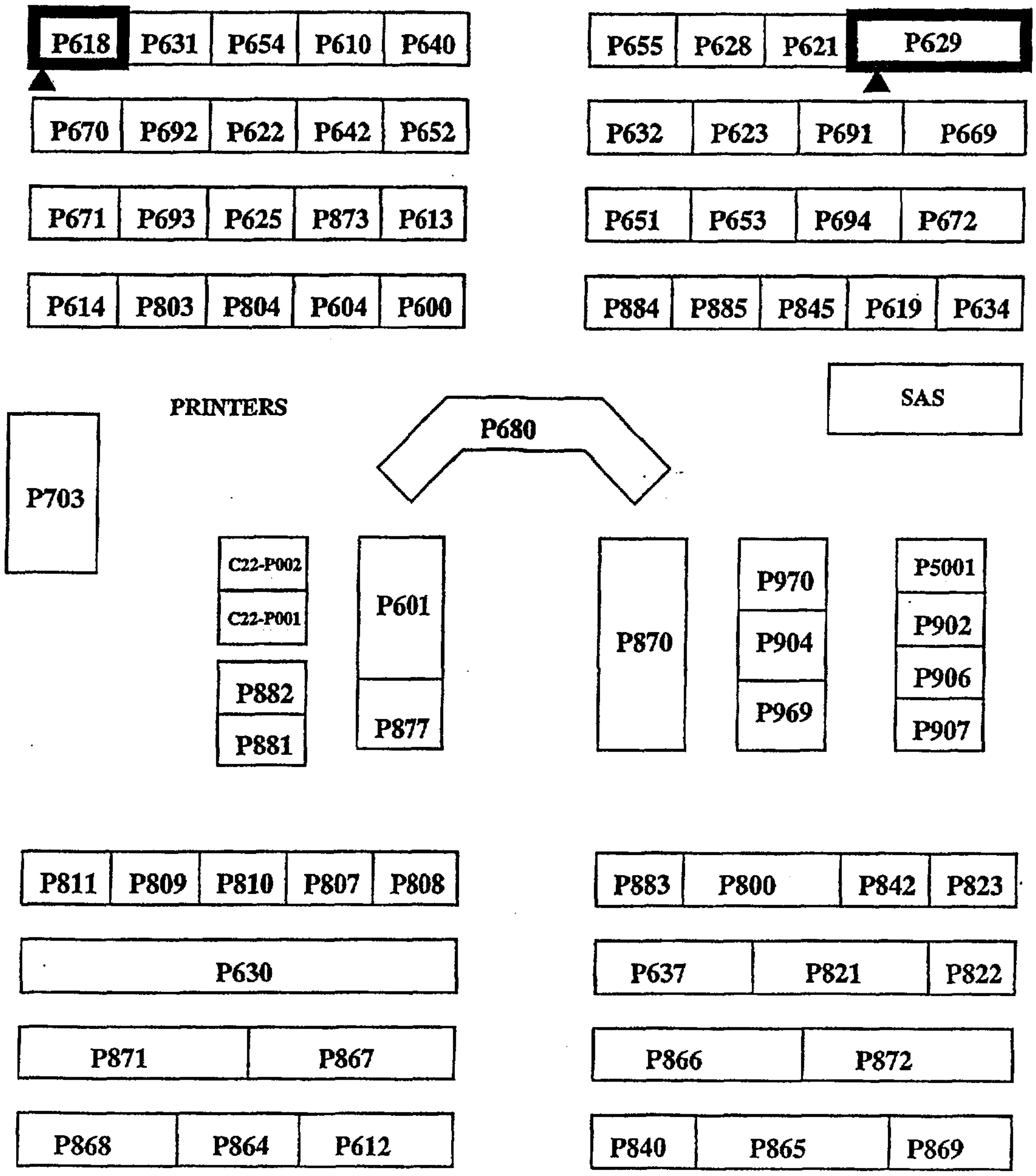
3.7.4.1 **OPEN** RHR A(B) HX'S OUTLET VALVE E12-F003A(B).

3.7.4.2 **THROTTLE** open RHR A(B) TEST VALVE TO SUPR POOL E12-F024A(B) to obtain 7100-7200 gpm.

=====================END OF INSTRUCTION STEPS=======================

PEI-SPI 3.1 Containment Spray Operation (Continued)

Control Room Back Panel Locations



QUESTION 065

Given the following:

- The plant is in Mode 5 with refueling operations in progress.
- The refuel position one-rod-out interlock surveillance was last completed satisfactory at 0800.
- Then, when performed again at 2130 by operations, the one-rod-out interlock surveillance failed.

WHAT actions are required in accordance with PNPP Technical Specifications?

a) Immediately suspend loading of irradiated fuel into the RPV; initiate action to restore Secondary Containment to operable.

b) ***Immediately suspend in-vessel fuel movement with equipment associated with the inoperable interlock and insert all insertable control rods.***

c) **Immediately suspend control rod withdrawal and initiate actions to fully insert all insertable control rods in cells containing one or more fuel assemblies.**

d) Immediately initiate action to insert all insertable control rods and place the mode switch in the SHUTDOWN position in 1 hour.

Comment:
The question states the "surveillance" fails and both specifications are in the surveillance, not just the one rod out interlock. The surveillance SVI-C71-T0427, covers SR 3.9.1.1 and 3.9.2.2 making B and C correct.

Reference: SVI-C71-T0427
SR 3.9.1.1
SR 3.9.2.2

Licensee's Position:

The utility believes that there are two correct answers

QUESTION 066

Based upon further review by the Utility, the appeal for this question is being withdrawn.

PERRY OPERATIONS MANUAL

Surveillance Instruction

Q65

TITLE: RX MODE SWITCH REFUEL MODE CHANNEL FUNCTIONAL

REVISION: 5 EFFECTIVE DATE: 11-21-02

PREPARED: Gary Kirsch 10-2-02
/ Date

SCOPE OF REVISION:

Rev. 5 -
1. Added reference to Surveillance Work Orders (SWO).
2. Changed MPL to Asset.
3. Updated Supervising Operator (SO) to Reactor Operator (RO) to match FENOC titles.
4. Minor format and administrative changes.
5. Revised inoperability notification format per CR 02-00241.
6. Added four step removal sequence for disconnecting cable.
7. Removed requirement to use Word Simulators for first performance. (OMCR 01-0091)
8. PICs from previous revision evaluated for incorporation - PIC-1, 2, 3, 4, 5, 6, 7, 8, 9, and 11.

Rx Mode Switch Refuel Mode Channel Functional

1.0 DESCRIPTION

1.1 Scope: Instruction demonstrates operability of Reactor Mode Switch REFUEL Position interlocks by performance of two channel functional tests.

Q65

Instruction fully satisfies functional surveillance requirements of Technical Specifications SR 3.9.1.1 and SR 3.9.2.2.

Instruction verifies operability for Reactor Mode Switch REFUEL Position interlocks:

1. Refuel Position One-Rod-Out Interlock
2. Refueling Equipment Interlocks
    a. All-rods-in
    b. Refuel platform position
    c. Refuel platform main hoist, fuel loaded

1.2 Frequency: At least once per 7 days.

1.3 Technical Specification Applicable MODES:

During in-vessel fuel movement with equipment associated with the interlocks.

MODE 5 with the reactor mode switch in the refuel position and any control rod withdrawn.

2.0 PRECAUTIONS AND LIMITATIONS

1. Steps marked with dollar sign ($) immediately to left are required by Technical Specifications. Such items, if found to exceed Allowable Values or found to be inoperable, may be NRC reportable and shall be brought to immediate attention of US.
2. Steps designated with initial block/lines are to be initialed as values entered or step completed. These steps may require additional initials or signatures to be entered on attachments or Data Package Cover Sheet (DPCS)/Surveillance Work Order (SWO).
3. Instruction should be read completely before proceeding with performance.
4. Steps shall be performed in sequence and instruction carried through to completion unless directed otherwise.

5. US shall be notified immediately if instruction step cannot be completed as stated or if problems develop during instruction performance.

6. Actions taken in this instruction cause Reactor Mode Switch REFUEL Position interlocks to be inoperable.

7. Channels made inoperable in Section 5.0 for:

   Refueling Equipment Interlock
   Refuel Position One-Rod-Out Interlocks
   Single Control Rod Withdrawal-Cold Shutdown
   Single Control Rod Drive (CRD) Removal-Refueling
   Multiple Control Rod Withdrawal-Refueling

8. Refueling platform and equipment shall be operated in accordance with SOI-F11/15, Fuel Handling, Refueling and Auxiliary Platforms (Unit 1).

9. During instruction performance, the following annunciator and status lights may come on:

   a. Annunciator ROD WITHDRAWAL BLOCK (UNIT CONTROL CONSOLE 1H13-P680-05A-E10).
   b. Status light INSERT REQUIRED CH 1 and CH 2 (P680-05C).
   c. Status light WITHDRAWAL BLOCK CH 1 and CH 2 (P680-05C).

3.0 MANPOWER AND EQUIPMENT

3.1 Manpower/Location/Communication

1. Five individuals are recommended:

   a. Control Room Operator to perform switch manipulations and collect data.
   b. Two fuel handling personnel to manipulate refuel platform and limit switches.
   c. Two technicians to disconnect cables, connect probe word simulators and simulate rod withdrawal on 620' level in containment.

2. Establish communications among personnel.

3.2 Required Measuring and Test Equipment (M&TE)

None

3.3 Additional Tools and Equipment

1. SOI-F11/15, Fuel Handling, Refueling and Auxiliary Platforms (Unit 1).

2. 2 RCIS Probe Word Simulators, if required.

3. Test Weight, 1L70-M0002E, Block #1 (372 lbs. dry) or Dummy Fuel Bundle (bottom of Dryer Pool).

4.0 PREREQUISITES — Initials

1. Obtain US's signature for Work Start on DPCS/SWO. ________

2. Instruction may be performed provided following conditions verified:

   a. Plant in MODE 3, 4, or 5. ________
   b. Refueling Platform ready for operation in accordance with SOI-F11/15 with Dryer Storage Pool/Reactor Well Gate removed per IOI-9. If Section 5.1.3 will not be performed, N/A this step's initial line. ________

3. Request RO verify all control rods inserted with exception of control rod(s) removed per Technical Specifications 3.10.4, 3.10.5, or 3.10.6. ________

4. At P680, if REACTOR MODE SWITCH 1C71A-S1 (P680-11E2) in SHUTDOWN, perform the following. If REACTOR MODE SWITCH in REFUEL, N/A this step's initial lines.

   a. Request RO have a second licensed operator or other technically qualified member of the unit technical staff verify all control rods remain fully inserted with the exception of control rod(s) removed per Technical Specifications 3.10.4, 3.10.5, or 3.10.6.

      Obtain individual's signature. ______________________ ________
      Signature

   b. Request RO place REACTOR MODE SWITCH 1C71A-S1 (P680-11E2) in REFUEL. ________

5. Verify the following:

   a. Annunciator ROD WITHDRAWAL BLOCK (P680-05A-E10) reset. ________
   b. Status light WITHDRAWAL BLOCK (P680-05C) CH 1 and CH 2 off. ________
   c. Status light INSERT REQUIRED (P680-05C) CH 1 and CH 2 off. ________

5.0 SURVEILLANCE INSTRUCTION — Initials

NOTE: Instruction divided into the following:

5.1.1 Test Preparation
5.1.2 Refuel Position One Rod Out Interlock
5.1.3 Refueling Equipment Interlocks
5.1.4 Test Restoration

5.1 Surveillance Test

5.1.1 Test Preparation

1. Print LEAD TEST PERFORMER's name on Attachment 3. ________

2. Obtain RO's Authorization for Test Start on DPCS/SWO. Detach Attachment 3 and give to RO. ________

3. Fill in START TIME/DATE, TEST NUMBER, TEST TITLE, and LEAD PERFORMER in Test Tracking Index. ________

4. Inform US of channels inoperability:

Technical Specification 3.9.1 Actions required during in-vessel fuel movement with equipment associated with the interlocks for:

Refueling Equipment Interlocks 3.9.1

Technical Specification 3.9.2 Actions required in MODE 5 with the reactor mode switch in the refuel position and any control rod withdrawn for:

Refuel Position One-Rod-Out Interlocks 3.9.2

Technical Specification 3.10.4 Actions required in MODE 4 with the reactor mode switch in the refuel position for:

Single Control Rod Withdrawal-Cold Shutdown 3.10.4

Technical Specification 3.10.5 Actions required in MODE 5 with LCO 3.9.5 not met for:

Single Control Rod Drive (CRD) Removal-Refueling 3.10.5

Technical Specification 3.10.6 Actions required in MODE 5 with LCO 3.9.3, LCO 3.9.4, or LCO 3.9.5 not met for:

Multiple Control Rod Withdrawal-Refueling 3.10.6

Record time and date. Obtain US's signature.

________/________ ________________________________ ________
Time Date US Signature

SECTION 5.1.2 | Initials

5.1.2 Refuel Position One Rod Out Interlock

NOTE: Controls and indicators used in this section are located on P680.

1. Request RO confirm SRM operability per Technical Specification 3.3.1.2. ________

2. Perform the following. If a control rod cannot be withdrawn and RCIS Probe Word Simulators must be installed, N/A this step's initial lines.

   a. Request RO withdraw one control rod to position 02 in Individual Drive. ________
   b. Record number of partially withdrawn control rod.

   Control Rod # ______-______ ________

3. Request RO perform the following. If a control rod can be withdrawn and simulators not installed, N/A this step's initial lines.

   a. Verify SEQUENCE "A" selected. ________
   b. Select rod 30-59. ________

4. On 620' level in containment, perform the following. If simulators not installed, N/A this step's initial lines.

   a. In 1H22-P071-A3, locate cable 1C11R96A on rod 30-59 connector. ________
   b. Independently verify cable 1C11R96A on rod 30-59 connector located. Independent Verifier: ________
   c. Disconnect cable 1C11R96A from rod 30-59 connector. ________
   d. Independently verify cable 1C11R96A disconnected from rod 30-59 connector. Independent Verifier: ________
   e. Connect RCIS Probe Word Simulator to Mux cabinet on connector where cable 1C11R96A disconnected and simulate position 02. ________
   f. In 1H22-P072-A3, locate cable 1C11R524B on rod 30-59 connector. ________
   g. Independently verify cable 1C11R524B on rod 30-59 connector located. Independent Verifier: ________
   h. Disconnect cable 1C11R524B from rod 30-59 connector. ________
   i. Independently verify cable 1C11R524B disconnected from rod 30-59 connector. Independent Verifier: ________
   j. Connect RCIS Probe Word Simulator to Mux cabinet on connector where cable 1C11R524B disconnected and simulate position 02. ________

SECTION 5.1.2

Initials

5. Confirm status light INSERT REQUIRED (P680-5C) CH 1 and CH 2 on. ________

6. Request RO engage ROD SELECT CLEAR pushbutton. ________

7. Confirm selected rod does not clear. ________

8. Request RO disengage ROD SELECT CLEAR pushbutton. ________

9. Request RO attempt to select another rod. ________

$ 10. Confirm another rod cannot be selected. ________

11. Perform the following:

    a. Request RO insert partially withdrawn control rod to position 00 and N/A initial line for Step 5.1.2.11.c. If simulators installed, N/A this step's initial line. ________
    b. Confirm rod recorded in Step 5.1.2.2.b indicates 00. If simulators installed, N/A this step's initial line. ________
    c. Simulate rod insertion to position 00 with both simulators. ________

12. Confirm the following status lights off:

    a. INSERT REQUIRED (P680-05C) CH 1 and CH 2. ________
    b. WITHDRAWAL BLOCK (P680-05C) CH 1 and CH 2. ________

13. Request RO press DRIVE MODE pushbutton and confirm GANG DRIVE mode selected. ________

14. Confirm the following:

$ a. Status light WITHDRAWAL BLOCK (P680-05C) CH-1 and CH-2 on. ________
    b. Annunciator ROD WITHDRAWAL BLOCK (P680-05A-E10) on. ________

15. Request RO press DRIVE MODE pushbutton and confirm INDIVIDUAL DRIVE selected. ________

16. Confirm the following:

    a. Status light WITHDRAWAL BLOCK (P680-05C) CH 1 and CH 2 off. ________
    b. Annunciator ROD WITHDRAWAL BLOCK (P680-05A-E10) reset. ________

SECTION 5.1.2

Initials

17. Request RO engage ROD SELECT CLEAR pushbutton. ________

18. Confirm selected rod clears. ________

19. Request RO disengage ROD SELECT CLEAR pushbutton. ________

20. On 620′ level in containment, perform the following. If Section 5.1.3 to be performed or if simulators not installed in Step 5.1.2.4, N/A this step′s initial lines.

    a. In 1H22-P071-A3, disconnect RCIS Probe Word Simulator from Mux cabinet. ________
    b. Connect cable 1C11R96A to rod 30-59 connector. ________
    c. Independently verify cable 1C11R96A connected to rod 30-59 connector. Independent Verifier: ________
    d. In 1H22-P072-A3, disconnect RCIS Probe Word Simulator from Mux cabinet. ________
    e. Connect cable 1C11R524B to rod 30-59 connector. ________
    f. Independently verify cable 1C11R524B connected to rod 30-59 connector. Independent Verifier: ________
    g. Verify rod 30-59 indicates correct position. ________

21. If only performing Refuel Position One Rod Out Interlock check, N/A initial lines for Section 5.1.3 and proceed to Section 5.1.4. If not, N/A this step′s initial line and proceed to Section 5.1.3. ________

5.1.3 Refueling Equipment Interlocks

NOTE: Overvessel switches S1 and S2 are tested assuming an approach to the vessel from the south.

1. Request RO select rod recorded in Step 5.1.2.2.b or rod 30-59 if simulators used. ________

2. On Refuel Bridge Operator Status Console, confirm the following status lights off:

    a. OVER VESSEL S1. ________
    b. OVER VESSEL S2. ________

3. Request RO move Refuel Bridge toward vessel until status light OVER VESSEL S1 on. ________

4. Confirm status light OVER VESSEL S2 on. ________

5. Request RO move Refuel Bridge away from vessel until status light OVER VESSEL S2 off. ________

6. Confirm status light OVER VESSEL S1 off. ________

SECTION 5.1.3 | Initials

7. Request RO move Refuel Bridge Main Hoist one foot in downward direction. ________

8. Confirm Refuel Bridge Main Hoist moved in downward direction. ________

9. Request RO move Refuel Bridge Main Hoist one foot in upward direction. ________

10. Confirm Refuel Bridge Main Hoist moved in upward direction. ________

11. On Refuel Bridge Operator Left Console, confirm status light HOIST LOADED off. ________

12. In 1H13-P651 (CONTROL ROD POSITION PANEL), confirm Refuel Platform Fuel Loaded (PG) LED off. ________

13. In 1H13-P652, confirm Refuel Platform Fuel Loaded (PG) LED off. ________

14. Request RO lift Test Weight Block #1 (or Dummy Fuel Bundle) using Refuel Bridge Main Hoist, above 15 IN and out of weight test area to clear RED ZONE light. ________

15. On Refuel Bridge Operator Left Console, confirm status light HOIST LOADED on. ________

16. In P651, confirm Refuel Platform Fuel Loaded (PG) LED on. ________

17. In P652, confirm Refuel Platform Fuel Loaded (PG) LED on. ________

18. On Refuel Bridge Operator Status Console, confirm status light ROD BLOCK 2 INTERLOCK off. ________

19. On P680, confirm the following:

    a. Annunciator ROD WITHDRAWAL BLOCK (P680-05A-E10) reset. ________
    b. Status light WITHDRAWAL BLOCK (P680-05C) CH 1 and CH 2 off. ________

20. In P652, confirm Refuel Platform Overcore (PC) LED off. ________

21. Request RO hold Limit Switch S2 in actuated (up) position until Step 5.1.3.25. See Attachment 3 for location. (Simulates Refuel Bridge being located over reactor vessel.) ________

SECTION 5.1.3 Initials

$ 22. On Refuel Bridge Operator Status Console, confirm status light ROD BLOCK 2 INTERLOCK on. ________

23. At P680, confirm the following:

   a. Annunciator ROD WITHDRAWAL BLOCK (P680-05A-E10) on. ________

$ b. Status light WITHDRAWAL BLOCK (P680-05C) CH 2 on. ________

24. In P652, confirm Refuel Platform Overcore (PC) LED on. ________

25. Request RO release Limit Switch S2. ________

26. On Refuel Bridge Operator Status Console, confirm status light ROD BLOCK 2 INTERLOCK off. ________

27. At P680, confirm the following:

   a. Annunciator ROD WITHDRAWAL BLOCK (P680-05A-E10) reset. ________
   b. Status light WITHDRAWAL BLOCK (P680-05C) CH 1 and CH 2 off. ________

28. In P652, confirm Refuel Platform Overcore (PC) LED off. ________

29. Perform the following. If a control rod cannot be withdrawn and simulators are installed, N/A this step's initial lines.

   a. Request RO withdraw one control rod to position 02 in Individual Drive. ________
   b. Record number of partially withdrawn control rod.

   Control Rod # ______-______ ________

30. Request RO perform the following. If a control rod can be withdrawn and simulators not installed, N/A this step's initial lines.

   a. Verify SEQUENCE "A" selected. ________
   b. Select rod 30-59. ________

31. On 620' level, simulate rod position 02 on both simulators. If simulators not installed, N/A this step's initial line. ________

32. On Refuel Bridge Operator Status Console, confirm the following status lights off:

   a. ROD BLOCK 1 INTERLOCK. ________
   b. REFUEL INTERLOCK. ________
   c. BRIDGE REV. STOP 1. ________

SECTION 5.1.3 — Initials

33. In P651, confirm Refuel Platform Overcore (PC) LED off. ________

34. Request RO hold Limit Switch S1 in actuated (up) position until Step 5.1.3.47. See Attachment 3 for location. (Simulates Refuel Bridge being located over reactor vessel.) ________

35. On Refuel Bridge Operator Status Console, confirm the following status lights on:

$ a. ROD BLOCK 1 INTERLOCK. ________
$ b. REFUEL INTERLOCK. ________
$ c. BRIDGE REV. STOP 1. ________

36. At P680, confirm the following:

a. Annunciator ROD WITHDRAWAL BLOCK (P680-05A-E10) on. ________
$ b. Status light WITHDRAWAL BLOCK (P680-05C) CH 1 on. ________

37. In P651, confirm Refuel Platform Overcore (PC) LED on. ________

38. Request RO turn RAISE/LOWER GRAPPLE rheostat on Refuel Bridge Operator Right Console toward RAISE direction and hold until Step 5.1.3.40. ________

$ 39. Confirm hoist does not move. ________

40. Request RO release RAISE/LOWER GRAPPLE rheostat. ________

41. Request RO depress JOG DOWN pushbutton on Refuel Bridge Operator Right Console and hold until Step 5.1.3.43. ________

$ 42. Confirm hoist does not move. ________

43. Request RO release JOG DOWN pushbutton. ________

44. Request RO rotate Bridge Speed Control on Refuel Bridge Operator Right Console to REVERSE and hold until Step 5.1.3.46. ________

$ 45. Confirm bridge does not move. ________

46. Request RO release Bridge Speed Control. ________

47. Request RO release Limit Switch S1. ________

SECTION 5.1.3

Initials

48. On Refuel Bridge Operator Status Console, confirm the following status lights off:

    a. REFUEL INTERLOCK. _______
    b. ROD BLOCK 1 INTERLOCK. _______
    c. ROD BLOCK 2 INTERLOCK. _______
    d. BRIDGE REV. STOP 1. _______
    e. OVER VESSEL S1. _______
    f. OVER VESSEL S2. _______

49. At P680, confirm the following:

    a. Annunciator ROD WITHDRAWAL BLOCK (P680-05A-E10) reset. _______
    b. Status light WITHDRAWAL BLOCK (P680-05C) CH 1 and CH 2 off. _______

50. Request RO place Test Weight Block #1 (or Dummy Fuel Bundle) in safe condition and ungrapple. _______

51. On Refuel Bridge Left Console, confirm status light HOIST LOADED off. _______

52. Perform the following:

    a. Request RO insert partially withdrawn control rod to position 00 and N/A initial line for Step 5.1.3.52.c. If simulators installed, N/A this step's initial line. _______
    b. Confirm rod recorded in Step 5.1.3.29.b indicates 00. If simulators installed, N/A this step's initial line. _______
    c. Simulate rod insertion to position 00 with both simulators. _______

53. On 620' level in containment, perform the following. If simulators not installed in Step 5.1.2.4, N/A this step's initial lines.

    a. In 1H22-P071-A3, disconnect RCIS Probe Word Simulator from Mux cabinet. _______
    b. Connect cable 1C11R96A to rod 30-59 connector. _______
    c. Independently verify cable 1C11R96A connected to rod 30-59 connector. Independent Verifier: _______
    d. In 1H22-P072-A3, disconnect RCIS Probe Word Simulator from Mux cabinet. _______
    e. Connect cable 1C11R524B to rod 30-59 connector. _______
    f. Independently verify cable 1C11R524B connected to rod 30-59 connector. Independent Verifier: _______
    g. Verify rod 30-59 indicates correct position. _______

Section 5.1.4 | Initials

5.1.4 Test Restoration

1. Inform US of channel operability. Record time and date. Obtain US's signature.

_______/_______ ______________________________ _________
Time Date US Signature

5.2 Plant/System Restoration

1. Inform RO of system restoration. _________

2. Fill in STOP TIME/DATE in Test Tracking Index. _________

5.3 Acceptance Criteria

NOTE: Satisfactory instruction completion based on Technical Specification items (marked with dollar sign).

1. All Technical Specification required items as indicated by dollar signs ($) performed satisfactorily.

   [ ] YES [ ] NO, US notified _________

2. All other items performed satisfactorily.

   [ ] YES [ ] NO, I&C Supervisor notified _________

3. Check blocks on DPCS/SWO to indicate acceptable or unacceptable test results. _________

5.4 Records

The following records are generated by this instruction:

Quality Assurance Records

Data Package Cover Sheet/Surveillance Work Order
SVI-C71-T0427, pages 3 through 12, and:
  Attachment 1, M&TE/Comment/Signature Sheet

Non-Quality Records

None

6.0 REFERENCES

6.1 Technical Specifications

6.2 Drawings

B-208-020
B-208-086

6.3 Vendor/Technical Manuals

GEK 75559 Perry 1/2 Operations and Maintenance Instruction REFUELING PLATFORM EQUIPMENT ASSEMBLY 767E457G8, G14, E.A. Number 2, 4/10/84 (File # 147G)

6.4 Commitments

The following commitments are either partially or fully satisfied by this instruction:

None

7.0 ATTACHMENTS

7.1 Attachment 1 - M&TE/Comment/Signature Sheet.

7.2 Attachment 2 - Reference Drawing.

7.3 Attachment 3 - Alarm, Status/Indication Light, and General Information List.

Rx Mode Switch Refuel Mode Channel Functional

M&TE/Comment/Signature Sheet

Comments: ______________________________

Performed By: ______________ / ______ / ______

______________ / ______ / ______

______________ / ______ / ______

______________ / ______ / ______

Independent Verifier: ______________ / ______ / ______

______________ / ______ / ______

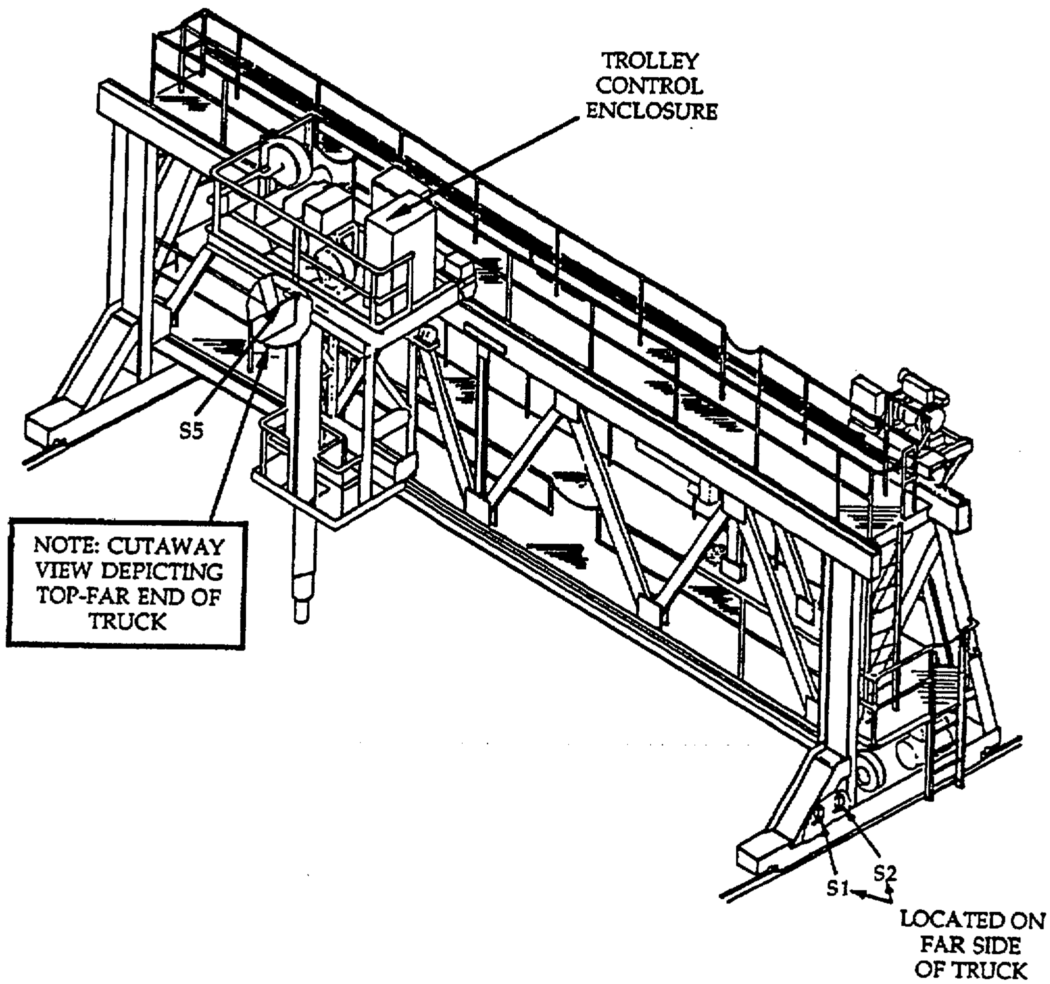
______________ / ______ / ______

______________ / ______ / ______

Signature | Initials | Date

Reference Drawing

Refueling Platform



Alarm, Status/Indication Light, and General Information List

SVI Title: Rx Mode Switch Refuel Mode Channel Functional

NOTE: This attachment is for information only and is provided as an aid to the RO. Additional alarms and/or plant impact may occur due to the specific plant conditions at the time of performance. Desired changes to this attachment should be documented in the Comments section of the DPCS/SWO.

The following alarm may be received intermittently:

ALARM	LOCATION
Annunciator ROD WITHDRAWAL BLOCK	P680-05A-E10

The following status lights may come on or go off intermittently:

STATUS LIGHTS	LOCATION
Status light INSERT REQUIRED CH 1 and CH 2	P680-05C
Status light WITHDRAWAL BLOCK CH 1 and CH 2	P680-05C

PLANT IMPACT:

At least (3) three Rod Block signals will be generated during performance of this instruction. Refuel Bridge will be unavailable for use if Section 5.1.3 performed.

LEAD TEST PERFORMER: ______________________________
(PRINT)

3.9 REFUELING OPERATIONS

3.9.1 Refueling Equipment Interlocks

LCO 3.9.1 The refueling equipment interlocks shall be OPERABLE.

APPLICABILITY: During in-vessel fuel movement with equipment associated with the interlocks.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more required refueling equipment interlocks inoperable.	A.1	Suspend in-vessel fuel movement with equipment associated with the inoperable interlock(s).	Immediately
	<u>OR</u>		
	A.2.1	Insert a control rod withdrawal block.	Immediately
		<u>AND</u>	
	A.2.2	Verify all control rods are fully inserted.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.1.1	Perform CHANNEL FUNCTIONAL TEST on each of the following required refueling equipment interlock inputs: a. All-rods-in, b. Refuel platform position, and c. Refuel platform main hoist, fuel loaded.	7 days

Q65

3.9 REFUELING OPERATIONS

3.9.2 Refuel Position One-Rod-Out Interlock

LCO 3.9.2 The refuel position one-rod-out interlock shall be OPERABLE.

APPLICABILITY: MODE 5 with the reactor mode switch in the refuel position and any control rod withdrawn.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Refuel position one-rod-out interlock inoperable.	A.1 Suspend control rod withdrawal.	Immediately
	<u>AND</u>	
	A.2 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.2.1	Verify reactor mode switch locked in refuel position.	12 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.9.2.2	-------------------NOTE------------------- Not required to be performed until 1 hour after any control rod is withdrawn. --	
	Perform CHANNEL FUNCTIONAL TEST.	7 days

Q65

QUESTION 073

Select the statement below that reflects an Operations Section expectation for TRANSIENT ALARM RESPONSE during implementation of Plant Emergency Instructions (PEI).

a) ***Entry in to the TRANSIENT ALARM RESPONSE mode shall be announced by the Unit Supervisor.***

b) **Locked in alarms that are abnormal for the present plant status should be communicated to the Unit Supervisor.**

c) Recurring alarms that annunciate ONI or PEI entry conditions do NOT need to be re-announced.

d) The TRANSIENT ALARM RESPONSE mode will remain in effect until the PEIs are exited.

Comment:
Reference for transient response (PYBP-POS-2-3) to this question. Answer A is correct because the alarm response mode shall be given at the next brief. This would make answer A correct. Answer B is also correct during transient response, as it is the RO's responsibility to report alarms that are not normal for the situation.

Reference: NOBP-POS-2-3

Licensee's Position:

The utility believes that there are two correct answers

QUESTION 074

Based upon further review by the Utility, the appeal for this question is being withdrawn.

QUESTION 075

Based upon further review by the Utility, the appeal for this question is being withdrawn.

5.4 Alarm Response/ARI Usage

During Emergency/ Off-Normal conditions, critical alarms may indicate degradation in the level of plant or personnel safety, potential for equipment damage, or direct entry and actions using emergency or off-normal procedures. Identified critical alarms shall be communicated to the Unit Supervisor. During Emergency/ Off-Normal conditions, annuciators that are not critical or are expected based upon

Q73

plant conditions, do not need to be communicated. The Unit Supervisor shall announce entry into transient annuciator response during the first transient crew briefing. As time permits, annunciator reviews are performed for unexpected conditions and Alarm Response Instructions are reviewed for plant response. Following Emergency/ Off-Normal conditions and when the plant has been stabilized, the Unit Supervisor shall announce the resumption of normal annunciator alarm instruction response.

The reactor operator or balance of plant operator shall own alarm response instructions. This performance will be in conjunction with the execution of the ONIs and PEIs. The expectation is that the operators own the ARIs and will take appropriate action without interfering with execution of the ONIs or PEIs.
This allows the Unit Supervisor to maintain a control and oversight role during the transient.

Various annunciator windows are color coded to assist the operator in responding to multiple alarm events. Color-coding provides a visual indicator as a means to aid the operator in prioritizing alarm response. The color-coding is intended to be a tool to aid the operating crew set priorities based upon potential significance of the degrading plant conditions or equipment failures. All annuciators are important, however during the initial phases of a transient the red and amber windows require immediate evaluation.

5.5 ONI Usage

This section provides guidance for multiple ONI transient type events with the intention of relieving the Unit Supervisor of the need to direct each action step to the operators. The ability to assign owners for ONI actions is required to ensure that the oversight and control role of the Unit Supervisor is not compromised.

The Unit Supervisor is responsible for ensuring all ONI immediate and subsequent actions are addressed. The Unit Supervisor may assign all or part of the subsequent actions to the reactor operators. Attachment 1 provides a reference for suggested responsibilities for ONI actions.

QUESTION 079

The plant was operating at 100% power when a LOCA occurred. All control rods are fully inserted. LPCS and LPCI 'A' are both injecting into the RPV. NO other ECCS pumps are available. As long as both pumps are injecting, RPV water level can be maintained above TAF. Suppression Pool temperature is 130°F and rising. Select the statement below that correctly describes the use of LPCI 'A' for Suppression Pool cooling.

a) LPCI 'A' must be diverted to Suppression Pool Cooling to ensure that Suppression Pool temperature is maintained below the Heat Capacity Limit, since LPCS can maintain adequate core cooling through spray cooling alone.

b) ***LPCI 'A' may be diverted to Suppression Pool Cooling as long as LPCS is able to maintain RPV water level above -25 inches (the Minimum Steam Cooling RPV water level).***

c) LPCI 'A' must be diverted to Suppression Pool Cooling, irrespective of adequate core cooling, when neither Suppression Pool temperature nor Reactor pressure can be maintained below the Heat Capacity Limit (HCL)

d) **LPCI 'A' may be diverted to Suppression Pool Cooling only if additional injection sources become available to be used with LPCS to maintain RPV water level above 0 inches.**

Comment:
PEI bases defines adequate core cooling as level being above the Minimum Zero Injection Water Level. As Answer B states that LPCI may be diverted to Suppression Pool Cooling as long as LPCS can maintain RPV water level above –25 inches, (consistent with the non ATWS flow chart not requiring ED until level cannot be restored and maintained above –25 ") answer B is also correct. Answer D is correct because maintaining level above zero inches ensures the core is cooled.

Reference: PEI Bases Definition of Adequate Core Cooling
PEI B13 non ATWS flowchart

Licensee's Position:

The utility believes that there are two correct answers

QUESTION 086

Based upon further review by the Utility, the appeal for this question is being withdrawn.

The meaning of the following terms is discussed in the context of their use within the PEIs. This information is provided in order to facilitate a consistent and technically accurate understanding of the entry conditions, operator actions, cautions, and execution of the PEIs.

Q79

Adequate Core Cooling

Heat removal from the reactor sufficient to prevent rupturing the fuel clad. Within the EPGs, three viable mechanisms for establishing adequate core cooling are defined—core submergence, spray cooling, and steam cooling.

Submergence is the preferred method for cooling the core. The core is adequately cooled by submergence when it can be determined that RPV water level is at or above the top of the active fuel. All fuel nodes are then assumed to be covered with water and heat is removed by boiling heat transfer.

Adequate spray cooling is provided in BWR/3 through BWR/6 designs, assuming a bounding axial power shape, when design spray flow requirements are satisfied and RPV water level is at or above the elevation of the jet pump suctions. The covered portion of the core is then cooled by submergence while the uncovered portion is cooled by the spray flow. Currently this method is not used and is under design review to ensure that it is acceptable for use at Perry.

Steam cooling is relied upon only if RPV water level cannot be restored and maintained above the top of the active fuel, cannot be determined, or must be intentionally lowered below the top of the active fuel. The core is adequately cooled by steam if the steam flow across the uncovered length of each fuel bundle is sufficient to maintain the hottest peak clad temperature below the appropriate limiting value—1500°F if makeup can be injected, 1800°F if makeup cannot be injected. The covered portion of the core remains cooled by boiling heat transfer and generates the steam, which cools the uncovered portion.

Steam cooling with makeup capability if RPV water level cannot be restored and maintained above the top of the active fuel; during RPV flooding when the reactor may not be shutdown; if RPV water level is intentionally lowered below the top of the active fuel to reduce reactor power or if emergency RPV depressurization is required. When RPV water level cannot be restored and maintained above the top of the active fuel and when RPV water level is intentionally lowered below the top of the active fuel, adequate steam flow is established by maintaining RPV water level above the Minimum Steam Cooling RPV Water Level. When the reactor is not shutdown under all conditions without boron during RPV flooding and when emergency RPV depressurization is required under failure-to-scram conditions, adequate steam flow exists as long as RPV pressure is above the Minimum Steam Cooling Pressure. In all cases, the peak-clad temperature is limited to 1500°F, the threshold for fuel rod perforation.

Steam cooling without makeup capability is employed during steam cooling. With no makeup to the RPV, adequate steam flow exists as long as RPV water level remains above the Minimum Zero-Injection RPV Water Level. When RPV water level drops below this elevation, emergency depressurization must be performed. The peak clad temperature is permitted to rise to 1800°F, the threshold for significant metal-water reaction, to maximize the heat transfer to steam and to delay the depressurization as long as possible.

The minimum RPV water level at which adequate steam flow exists is higher when makeup capability exists because:

- The limiting fuel temperature is lower (1500°F). The higher limit of 1800°F is used only when cladding perforation cannot be avoided.
- With injection, water at the core inlet is subcooled. Some of the energy produced by the core must then be expended in raising the temperature of the liquid to saturation and less steam will be produced to cool the uncovered portions of the core.

The "adequate core cooling" state can be defined only within the context of the EPG guidelines and contingencies. Once conditions requiring entry of the SAGs exist, a normal core configuration can no longer be assumed and the same criteria cannot be applied. While one of the objectives of the SAGs is to submerge the core or core debris, restoring RPV water level to above the top of the active fuel in accordance with the RPV and Primary Containment Flooding guideline does not necessarily reestablish adequate core cooling.

<u>Assure</u>

Make certain that a specified state or condition is established and will be maintained. Encompasses an implied action to operate appropriate systems, as available, to accomplish the stated objective. Both direct and indirect indications may be used to determine that the specified state or condition has been achieved and will be maintained (refer to the discussion of "adequate core cooling").

<u>Available</u>

The state or condition of being ready and able to be used (placed into operation) to accomplish the stated (or implied) action or function. As applied to a system, this requires the operability of all necessary support systems (electrical power supplies, cooling water, lubrication, etc.) for the system/components to work as designed.

<u>Boron Injection Initiation Temperature</u>

Defined to be the greater of either:

- The suppression pool temperature at which initiation of a reactor scram is required by Technical Specifications, or,
- The highest suppression pool temperature at which initiation of boron injection using SLC will result in injection of the Hot Shutdown Boron Weight of boron before suppression pool temperature exceeds the Heat Capacity Limit.

Perry uses the first criteria as the limit.

<u>Bypassing</u>

Temporarily disabling the functioning of an automatic protection feature. As used in the PEIs, this term is generally limited to conditions where a bypass feature has been included in the system (e.g., bypassing a high drywell pressure interlock).

Inject Slowly

The phrase "Inject slowly..." in RPV Control (ATWS) - Level means if indicated level goes below the bottom of active fuel (BAF), injection into the vessel should be promptly increased with the available systems to restore level indication to just on-scale on the fuel zone instruments. Once on-scale indication is obtained, injection should then be reduced and controlled to slowly increase RPV level to the desired band. The injection rate should be controlled such that RPV power oscillations and spiking is minimized.

Line up for injection

Establish the initial conditions necessary for system operation including positioning of valves and breakers, installation of spool pieces, etc. as directed in the SPIs or, if not specified in the SPIs then per the respective system SOI.

Maintain below/above

Take the action necessary to prevent the value of the parameter from exceeding identified limits. Momentarily exceeding a parameter value due to instrumentation perturbation is excluded from this determination.

The Minimum Number of SRVs Required for Decay Heat Removal (MNSDHR) (2)

The least number of SRVs which, if opened, will remove all decay heat from the core at a pressure sufficiently low that the ECCS with the lowest head will be capable of making up the SRV steam flow.

The Minimum Steam Cooling Pressure (MSCP)

The lowest RPV pressure at which steam flow through open SRVs is sufficient to preclude any clad temperature from exceeding 1500°F even if the reactor core is not completely covered. The MSCP is a function of the number of open SRVs.

Minimum Number of SRVs Required for Emergency Depressurization (MNSRED) (5)

The least number of SRVs which corresponds to a Minimum Steam Cooling Pressure (MSCP) sufficiently low that the ECCS with the lowest head (LPCI) will be capable of making up the SRV steam flow at the corresponding MSCP. The MNSRED is utilized to ensure the RPV will depressurize and remain depressurized when emergency depressurization is required.

Q79

Minimum Steam Cooling RPV Water Level (MSCRWL) (-25")

The lowest RPV water level at which the covered portion of the reactor core will generate sufficient steam to prevent any clad temperature in the uncovered part of the core from exceeding 1500°F. This water level is utilized to preclude fuel damage when RPV water level is below the top of active fuel.

PERRY NUCLEAR POWER PLANT	Procedure Number: PEI Bases	
Title: PEI Bases Document	Use Category: Reference	
Plant Emergency Instruction (PEI) Operational Limits and Setpoints	Revision: 6	Page 38 of 392

RPV Level Setpoints

177.7 =178 in.	Low level scram setpoint.
100.75=100 in.	Two feet below the feedwater spargers
16.5 in.	ADS initiation setpoint.
0 in.	Top of Active Fuel (TAF).
Q79 -25 = -25 in.	Minimum Steam Cooling RPV Water Level.
-43.76 = -42.5 in.	Minimum Zero Injection RPV Water Level.
-45 in	Jet Pump Suction

RPV Pressure Setpoints

1064.7 = 1065 psig	High RPV pressure scram setpoint.
900 psig	Pressure at which all turbine bypass valves are fully open.
133 = 130 psig	Highest RPV pressure at which the shutoff head of a low-water-quality alternate injection subsystem (excluding SLC) is reached.
53.5=60 psig	Decay Heat Removal Pressure (above containment)

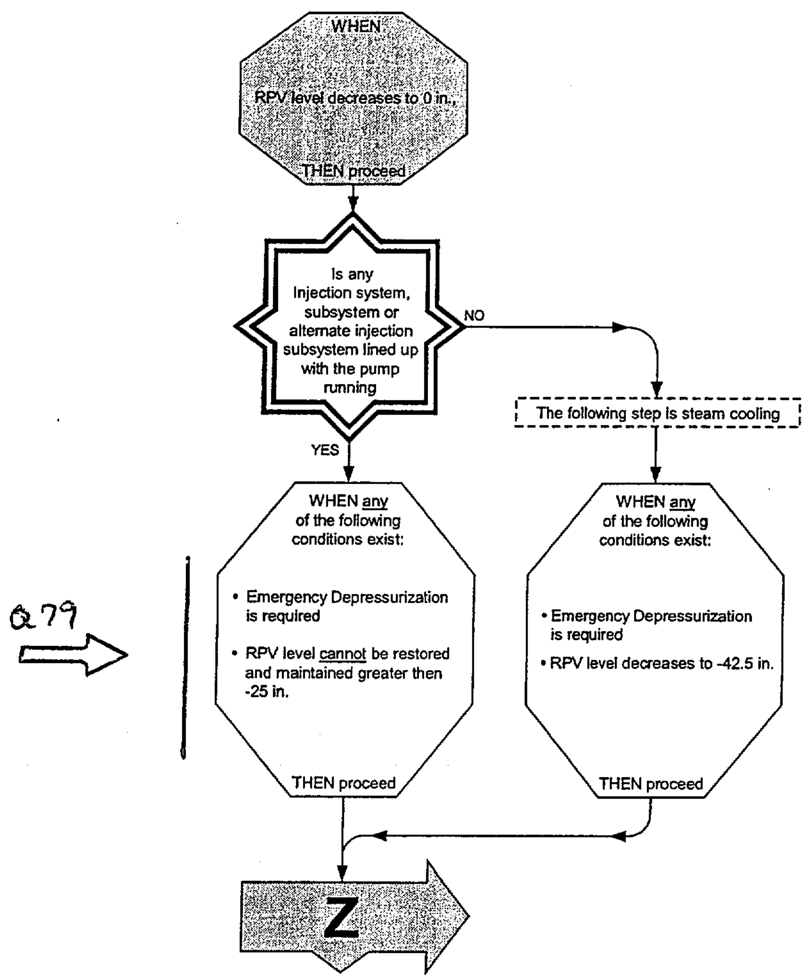
RPV Temperature Setpoints

Between 70°F and 200°F	RPV water temperature for cold shutdown conditions.
100°F/hr	RPV cooldown rate LCO.

Containment/Drywell Temperature Setpoints

95°F	Most limiting suppression pool temperature LCO and containment temperature LCO.
145°F	Drywell temperature LCO.
185°F	Containment design temperature and environmental qualification temperature for safety related electrical equipment in the containment.
330°F	Maximum temperature at which ADS is qualified, drywell design temperature.

STEP:



DISCUSSION

This override step applies throughout the performance of the remainder of RPV Level Control.

Emergency RPV depressurization permits injection from low head systems, maximizes the total injection flow, and minimizes the flow through any primary system break.

DISCUSSION (Continued)

If an injection source is not available then Steam Cooling is entered. If an RPV injection source becomes available during this time and RPV water level cannot be restored and maintained above the Minimum Steam Cooling RPV Water Level (MSCRWL)(-25"), then emergency RPV depressurization is required.

If the injection source can restore and maintain RPV water level above the MSCRWL, Steam Cooling is exited when RPV water level is increasing. Emergency RPV Depressurization is not immediately required for the following reasons:

- While peak cladding temperature could exceed 1800°F while RPV water level is increasing to the MSCRWL, the length of time required for the increase is expected to be short since the MZIRWL and MSCRWL are only approximately one foot apart. Provided the system continues to operate, the core will ultimately be cooled by submergence. Cooling by submergence is usually preferable to blowing down since submerging the core not only quenches the uncovered, heated portion of the core, but also adds inventory for long-term cooling.
- A blowdown would deplete the remaining inventory of water in the RPV. Since the available injection source must make up this lost inventory, the time required to raise RPV water level above the MSCRWL and cool the core by submergence could be lengthened.
- If RPV water level is increasing, the system is providing sufficient injection to overcome break flow.
- If RCIC is restored, depressurizing could result in a low RPV pressure isolation. Even if the system can be operated at low pressure by defeating isolation interlocks, continued operation without bypassing the interlocks is preferable since the system is designed for operation above the low RPV pressure isolation setpoint and normal operation imposes less workload upon the operating crew.

If attempts are unsuccessful in starting pumps in one or more systems, injection subsystems, or alternate injection subsystems, the operators will utilize Steam Cooling. Steam Cooling is performed by allowing RPV water level to decrease through boil off until it drops to the Minimum Zero-Injection RPV Water Level (-42.5 in.). During this period the fuel temperature in the uncovered portion of the core increases and heat is transferred from the fuel rods to the steam.

Minimum Zero-Injection RPV Water Level is defined as the lowest RPV water level at which the covered portion of the reactor core will generate sufficient steam to prevent any clad temperature in the uncovered portion of the core from exceeding 1800°F.

DISCUSSION (Continued)

If an injection source is available, emergency depressurization is delayed until RPV water level reaches the top of the active fuel, but may be performed anytime RPV water level is between the top of the active fuel and the Minimum Steam Cooling RPV Water Level.

- If it is expected that operating injection systems will reverse the level trend before RPV water level drops to the Minimum Steam Cooling RPV Water Level, the blowdown may be delayed.
- If it is believed that available injection systems are capable of restoring and maintaining RPV water level above the Minimum Steam Cooling RPV Water Level following RPV depressurization, the blowdown may be performed as soon as RPV water level reaches the top of the active fuel.
- If it is not expected that available injection systems will restore and maintain RPV water level above the Minimum Steam Cooling RPV Water Level following RPV depressurization, the blowdown should be delayed as long as possible.

The emergency depressurization should be performed even if RCIC is the only source of injection to the RPV. RCIC operation can continue even after the RPV has been depressurized, since the low pressure isolation may be defeated. The system can sustain some flow as long as RPV pressure is above the value at which the turbine stalls.

Emergency depressurization is not performed while RPV water level is above the top of the active fuel because:

- The core will remain adequately cooled as long as RPV water level remains above the Minimum Steam Cooling RPV Water Level.
- The time before RPV water decreases to the top of the active fuel can best be used to line up additional injection sources. If the decreasing RPV water level trend can be reversed, emergency depressurization may not be required.

The emergency depressurization requirement in this step is predicated upon three conditions:

- RPV water level has dropped at least to the top of the active fuel.
- At least one injection source is available.
- The available injection sources cannot restore and maintain RPV water level above the MSCRWL if a blowdown is not performed.

Immediate emergency RPV depressurization is thus not required, even with RPV water below the MSCRWL, if available injection sources can restore and maintain RPV water level above the MSCRWL.

The MSCRWL is the lowest RPV water level at which the covered portion of the reactor core will generate sufficient steam to preclude any clad temperature in the uncovered portion of the core from exceeding 1500°F assuming the most limiting top-peaked power shape prior to reactor shutdown.

QUESTION 092

Given the following conditions:

- Reactor Plant at 100% RTP
- The following annunciators are in alarm:
  - HOT SURGE TANK LEVEL HI
  - HTR 4 ISOL HOT SRG TK LEVEL HI
- The Extraction Steam supply and Steam Seal Evaporator drains to Heater 4 have automatically isolated
- N21-F220, Hot Surge Tank Level Control Bypass Valve indicates closed
- N21-F230, Hot Surge Tank Level Control Valve is partially open and is unresponsive to the Hot Surge Tank Level Controller signals (in either AUTO or MANUAL)
- Local manual control of N21-F230, Hot Surge Tank Level Control Valve was unsuccessful
- Hot Surge Tank level is 150" and increasing slowly

Which one of the following actions should you direct the ATC Operator to perform while maintaining current power level?

a) Shutdown one of the Condensate Booster Pumps.

b) ***Perform the "Securing Flow to the Hot Surge Tank" section of S01-N21***

c) **Throttle open Condensate Minimum Flow Recirculation Valve (N21-F245, Short Cycle Clean-Up Valve)**

d) ***Manually trip all Hotwell and Condensate Booster Pumps***

Comment:
There is no correct answer listed. With a Heater 4 isolation, the ATC is required to take the immediate actions of ONI-N36, which require the operator to reduce reactor power to less than 95%. The answer listed as correct is in the subsequent actions of the ARI, that would not be done until after the immediate actions are completed and power is decreased. This is asking the SRO to direct a supplemental action, prior to the required immediate action. If he did order supplemental actions, answers B (ARI H13-P680-0002-E2, action 4.7.3), C (ARI H13-P680-0002-E2, action 4.5), and D (ARI H13-P680-0002-E2, action 4.7.4) are all subsequent actions in the ARI that could be used for mitigating the Hot Surge Tank High level. In this situation, there would be three potential actions to mitigate the problem.

References: ARI-H13-P680-0002-E2
ONI-N36
SOI-N21

Licensee's Position:

The Utility believes the question should be deleted as the immediate actions of ONI-N36 require the operator to lower reactor power.

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PERRY NUCLEAR POWER PLANT	Instruction Number: ARI-H13-P680-0002-E2	
Title: HOT SURGE TANK LEVEL HI	Use Category: In Field Reference	
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1.0 CAUSE OF ALARM

1.1 Hot Surge Tank level greater than 131 inches as sensed by 1N21-N336.

1.2 Hot Surge Tank temperature below 300°, causing inaccurate remote indication/alarm of Hot Surge Tank level.

1.3 Failure of HOT SURGE TANK LEVEL CONTROL 1N21-F230, 1N21-R475, controller.

2.0 AUTOMATIC ACTION

Heater 4 will isolate on further increase to 134 inches.

3.0 IMMEDIATE OPERATOR ACTION

None

4.0 SUBSEQUENT OPERATOR ACTION

NOTE

At Hot Surge Tank temperatures below 300°F, HOT SURGE LEVEL & CNDS TO HTR 4 FLOW, will indicate up to 15 inches high. The tank level sight glass should be used if high level data is needed.

❑	4.1	**TAKE** manual control of HOT SURGE TANK LEVEL CONTROL.	**1N21-F230**	**1N21-R475**
❑	4.2	**REDUCE** Hot Surge Tank level to between 105-130 inches.	**1N21-F230**	**1N21-R475**
NA ❑	4.3	**IF** necessary, **THEN REFER TO** SOI-N21 and **PERFORM** Alternate Hot Surge Tank Level Control.		

NA 4.4 ☐ **IF** necessary,
THEN MANUALLY THROTTLE Hot Surge Tank Level Control locally. (HB 600' E/2) — **1N21-F230**

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NA 4.5 **IF** necessary,
THEN MANUALLY THROTTLE Hot Surge Tank Level Control Bypass, locally. (HB 600' E/2) — **1N21-F220**

- ☐ **THROTTLE OPEN** CNDS MIN RCIRC FLOW CONTROL. — **1N21-F245** **1N21-R247**
- ☐ **MAINTAIN** motor current for the operating CBPs < 353 amps.

☐ 4.6 **MAINTAIN** motor current for the operating Hotwell pumps < 195 amps.

NA 4.7

Hot Surge Tank level rises
Hot Surge Tank goes off scale high
THEN PERFORM the following:

> NOTE
>
> HOT SURGE LEVEL & CNDS TO HTR 4 FLOW, (blue pen) or local (sightglass) level indication may be used to determine Hot Surge Tank level. HEATER SHELL PRESS 4, local pressure indicator ERIS point N21EA040, or Process Computer point N36BA013 may be used to determine Hot Surge Tank pressure.

☐ 4.7.1 **VERIFY** HST LVL CV MANUAL CONTROL in OFF.

☐ 4.7.2 **VERIFY** HOT SURGE TANK LEVEL CONTROL in MANUAL and minimum. — **1N21-F230** **1N21-R475**

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NA 4.7.3 ☐ **IF** necessary,
THEN REFER TO SOI-N21 and **PERFORM** Securing Flow to the Hot Surge Tank.

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NA 4.7.4

Unable to stop Condensate flow to the Hot Surge Tank
Prior to reaching 120 PSIG Hot Surge Tank pressure
THEN PERFORM the following:

❑ • **MANUALLY TRIP** all Hotwell Pumps

❑ • **MANUALLY TRIP** all Condensate Booster Pumps

END OF SECTION

PERRY NUCLEAR POWER PLANT	Instruction Number: ONI-N36	
Title: LOSS OF FEEDWATER HEATING	Use Category: In Field Reference	
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Q92 ⇒ **LOSS OF FEEDWATER HEATING**

Effective Date: 8-30-04

Preparer: Dan Roniger / 8-10-04
Date

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1.0 ENTRY CONDITIONS

1.1 Alarms

- HTR 6A (6B) EXST & INLET DRNS ISOL LEVEL HIGH
- HTR 5A (5B) EXST & INLET DRNS ISOL LEVEL HIGH
- HTR 4 ISOL HOT SRG TK LEVEL HI
- HEATER 3A (3B) EXST ISOL LEVEL HIGH
- HEATER 2A (2B, 2C) LEVEL HIGH
- HEATER 1A (1B, 1C) LEVEL HIGH

1.2 Parameters

1.2.1 Decreasing feedwater temperatures **OR** differential temperatures as indicated on CONDENSATE SYSTEM TEMPERATURE recorder, 1N21-R216 and FEEDWATER TEMPERATURE recorder, 1N27-R066 on 1H13-P842.

1.2.2 Feedwater heater levels outside the normal operating range.

1.2.3 Feedwater heater pressures outside the normal operating range.

1.2.4 Feedwater heater temperatures outside the normal operating range.

2.0 AUTOMATIC ACTIONS

2.1 Possible rod block **AND/OR** reactor scram due to high neutron flux.

NOTE

The most probable cause of a loss of feedwater heating is the automatic isolation of a heater or heaters on high or high-high level. Refer to Attachment 2 for applicable isolation valves.

2.2 APRM flux levels increase with **NO** change in:

- Control rod position
- Recirculation flow

2.3 The following will occur on a heater isolation:

- The extraction steam block valve, positive assist check valve, and associated valves listed in Attachment 2 will close.
- The normal **AND** alternate drain valves for the affected heater modulate to return heater level to normal.
- Normal drains to the affected heater will be directed to the alternate drain path.

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3.0 IMMEDIATE ACTIONS

CAUTION

Operating with a reduced feedwater temperature (e.g., without all feedwater heaters in service) will increase the likelihood of power oscillations.

NOTE

Shifting Recirculation Pumps to slow speed from minimum FCV position will not appreciably increase the margin to thermal limits. Therefore, to minimize the transient to Recirculation Pumps, do not transfer them to slow speed.

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NA 3.1 **WHILE** core flow is > 58 Mlbm/hr, **THEN REDUCE** reactor power using Reactor Recirculation Flow Control Valves to meet all the following criteria:

- ☐ ≤ 95% reactor power
- ☐ Less than or equal to the power level prior to the loss of feedwater heating.

4.0 SUPPLEMENTAL ACTIONS

☐ 4.1 **REFER TO** ONI-C51 and **EXECUTE** concurrently with this instruction.

☐ 4.2 **MONITOR** Feedwater temperature

NA 4.3

The minimum required number of OPRMs to maintain trip capability are **NOT** OPERABLE.	
Feedwater temperature is more than 5°F below the 425.5°F curve of the FEEDWATER TEMPERATURE VERSUS CORE THERMAL POWER graph.	PDB-A0011
THEN USE the Backup Stability Protection Regions - Two Loop Power - Flow Reduced Feedwater Power To Flow Map	PDB-A0006

☐ 4.4 **MONITOR** the following for proper operation of individual heaters and heater strings:

- Level
- Temperature
- Pressure

NA 4.5 ☐ **IF** the high level alarm is received for feedwater heater 1, **THEN REFER TO** Attachment 1 to **VERIFY** the normal and alternate drain valves open. **1A** **1B** **1C**

NA 4.6 ☐ **IF** the high level alarm is received for feedwater heater 2, **THEN REFER TO** Attachment 1 to **VERIFY** the normal and alternate drain valves open. **2A** **2B** **2C**

NA 4.7 ☐ **IF** the high level alarm is received for feedwater heater 3, **THEN REFER TO** Attachment 2 to **VERIFY** the following valves close: **3A** **3B**

- Extraction steam block valve
- Positive assist check valve
- Associated valves

NA 4.8 ☐ **IF** the high level alarm is received for feedwater heater 5, **THEN REFER TO** Attachment 2 to **VERIFY** the following valves close: **5A** **5B**

- Extraction steam block valve
- Positive assist check valve
- Associated valves

NA 4.9 ☐ **IF** the high level alarm is received for feedwater heater 6, **THEN REFER TO** Attachment 2 to **VERIFY** the following valves close: **6A** **6B**

- Extraction steam block valve
- Positive assist check valve
- Associated valves

NA 4.10 ☐ **IF** feedwater heater 1 level rises to the high-high setpoint, **THEN REFER TO** Attachment 2 to **VERIFY** the associated valves close. **1A** **1B** **1C**

PERRY NUCLEAR POWER PLANT		Instruction Number: ONI-N36	
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NA 4.11 ☐ **IF** level continues to increase in feedwater heater 2 level rises to the high-high setpoint,
THEN REFER TO Attachment 2 to **VERIFY** the associated valves close. — **2A** **2B** **2C**

NA 4.12 ☐ **IF** the hot surge tank level rises to the high-high setpoint,
THEN REFER TO Attachment 2 to **VERIFY** the associated valves close.

NOTE
Recovery actions for feedwater heater #4 isolation are located in ARI-H13-P680-2-E1.

NA 4.13 ☐ **IF** Heater 1 **AND** 2 isolates on a high-high level in either heater,
THEN MONITOR level in the isolated heaters. — **A** **B** **C**

NA 4.14 **IF** necessary,
THEN OPEN the following shell side maintenance drain valves to prevent the isolated heater from flooding into the turbine blading.

		A	B	C
☐	• Heater 1A Maintenance Drain to Condenser	**1N26-F538A**		
☐	• Heater 1B Maintenance Drain to Condenser		**1N26-F538B**	
☐	• Heater 1C Maintenance Drain to Condenser			**1N26-F538C**
☐	• Heater 2A Maintenance Drain to Condenser	**1N26-F532A**		
☐	• Heater 2B Maintenance Drain to Condenser		**1N26-F532B**	

☐ • Heater 2C Maintenance Drain to Condenser **1N26-F532C**

NA 4.15

Heater pressure is low
Heater level is normal
THEN PERFORM the following:

☐ 4.15.1 **REFER TO** Attachment 2 to **VERIFY** the extraction steam block valve is open.

☐ 4.15.2 **CONFIRM NO** extraction steam leak by investigating the following:

- Alarms
- Sump levels
- Radiation levels

NA ☐ 4.15.3 **IF** a leak has occurred, **THEN REFER TO** ONI-N11, Pipe Break Outside Containment.

☐ 4.16 **REDUCE** main generator loading to within the allowable limits listed below:

Heater	Number of Trains Lost	Side of Heater Lost	RFP Steam Supply		
			Main	Extraction	Basis
1 & 2	1	Condensate	1125 MWe	1188 MWe	1
5	2	Extraction	938 MWe	1000 Mwe	2

☐ 4.17 **REDUCE** reactor power to within the allowable limits listed below:

Heater	Number of Trains Lost	Side of Heater Lost	Limit	Basis
1 & 2	1	Condensate	18,000 gpm Condensate flow	4
1 & 2	2	Condensate	9,000 gpm Condensate flow	4
3	2	Condensate	11,900 gpm Condensate flow	3
5, 6	2 Trains of the same heater	Feedwater	18,400 gpm Feedwater flow	3

Bases for limits:

1 To prevent undue loading and overstressing of any turbine part. (Isolation of extraction steam changes Main Turbine Stage pressures, stage pressure drops, and steam flow through the turbine so that bucket, diaphragm, and thrust loads are affected.)

2 To prevent the overloading of Feedwater Heaters 6A and 6B

3 Bypass line flow limitations

4 To minimize flow induced vibrations in the feedwater heater tubes

4.18 **REFER TO** SOI-N27 **AND/OR** SOI-N21 to **LINE UP** Isolated heaters.

NA 4.19 ❑ **IF** desired,
THEN REFER TO the following to **RETURN** isolated heaters to service as applicable:

- SOI-N27
- SOI-N21
- ARI-H13-P680-2 window E1

NA 4.20

In single recirculation loop operation
Final feedwater temperature is below the 425°F curve in Feedwater Temperature Versus Core Thermal Power, PDB-A0011
❑ **THEN REFER TO** IOI-3 to **REDUCE** reactor power to ≤ 23.8% (894 MWt) within 6 hours.

NOTE

For planned reductions in feedwater temperature, FTI-B0010 must be performed prior to feedwater temperature reduction.

NA 4.21 ❑ **IF** feedwater heaters have been returned to service,
THEN REFER TO IOI-3 to **RESTORE** reactor power level.

NA 4.22 ❑ **IF** the isolated heaters are **NOT** returned to service,
THEN REFER TO FTI-B0010, Preparation for Final Feedwater Temperature Reduction Operation.

NA 4.23 ☐ **IF** the appropriate actions of FTI-B0010 have been completed,
THEN REFER TO IOI-3 to **RESTORE** reactor power level.

5.0 REFERENCES

Commitment B00509 – Steps 4.2, 4.16

Commitment F01554 – Steps 3.1, 4.2

Commitment B00916 - Caution for Step 3.1, Step 3.1

6.0 RECORDS

The following records are completed/generated by this document:

Quality Assurance Records

None

Non-Quality Assurance Records

None

7.0 SCOPE OF REVISION

Rev. 8

1. Deleted immediate action to scram when in the increased awareness region.
2. Deleted actions to insert cram rods as a duplicate action of ONI-C51.
3. Deleted actions for verification of power limits and moved them to ONI-SPI-G4.
4. Reversed the order of Steps 4.21 and 4.22.

8.0 ATTACHMENTS

ATTACHMENT 1 - FEEDWATER HEATER NORMAL AND ALTERNATE DRAINS

ATTACHMENT 2 - FEEDWATER HEATER ISOLATION

ATTACHMENT 3 - TECHNICAL SPECIFICATION DISCUSSION

ATTACHMENT 1 - FEEDWATER HEATER NORMAL AND ALTERNATE DRAINS
Page 1 of 1

Heater	Normal drain valve	Alternate drain valve
6A	1N25-F290A	1N25-F280A
6B	1N25-F290B	1N25-F280B
5A	1N25-F340A	1N25-F330A
5B	1N25-F340B	1N25-F330B
3A	1N26-F120A 1N26-F130A	1N26-F180A
3B	1N26-F120B 1N26-F130B	1N26-F180B
2A	1N26-F050A	1N26-F070A
2B	1N26-F050B	1N26-F070B
2C	1N26-F050C	1N26-F070C
1A	1N26-F010A	1N26-F030A
1B	1N26-F010B	1N26-F030B
1C	1N26-F010C	1N26-F030C

ATTACHMENT 2 - FEEDWATER HEATER ISOLATION
Page 1 of 2

HTR	Extraction steam block valve	Positive assist check valve	Associated valves	
6A	1N36-F120A	1N36-F140A	1N25-F140A 1N25-F170A 1N25-F250A	MSR 1A
			1N25-F145A 1N25-F175A 1N25-F255A	MSR 2A
6B	1N36-F120B	1N36-F140B	1N25-F140B 1N25-F170B 1N25-F250B	MSR 1B
			1N25-F145B 1N25-F175B 1N25-F255B	MSR 2B
5A	1N36-F435A	1N36-F455A	1N25-F290A	HTR 6A
5B	1N36-F435B	1N36-F455B	1N25-F290B	HTR 6B
4	1N36-F260	1N36-F250A 1N36-F250B	1N33-F160	
3A	1N36-F380A	1N36-F390A	None	
3B	1N36-F380B	1N36-F390B	None	
2A	None	None	1N26-F120A	HTR 3A
			1N21-F145A 1N21-F170A	Condensate
2B	None	None	1N26-F130A 1N26-F130B	HTR 3A HTR 3B
			1N21-F145B 1N21-F170B	Condensate

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ATTACHMENT 2 - FEEDWATER HEATER ISOLATION
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HTR	Extraction steam block valve	Positive assist check valve	Associated valves	
2C	None	None	1N26-F120B	HTR 3B
			1N21-F145C 1N21-F170C	Condensate
1A	None	None	1N26-F050A	HTR 2A
			1N21-F145A 1N21-F170A	Condensate
1B	None	None	1N26-F050B	HTR 2B
			1N21-F145B 1N21-F170B	Condensate
1C	None	None	1N26-F050C	HTR 2C
			1N21-F145C 1N21-F170C	Condensate

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ATTACHMENT 3 - TECHNICAL SPECIFICATION DISCUSSION
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1.0 For unplanned reductions in feedwater temperature, comply with T.S. 3.3.2.1 Action A for the Control Rod Block Instrumentation.

2.0 For unplanned reductions in feedwater temperature comply with one of the following four options for the RPS and EOC-RPT Instrumentation:

- Restore the feedwater temperature within the Tech Spec Action Time(s)
- Disable the bypass (i.e., arm the Function) in accordance with the PDB-I0010 for RPS and EOC-RPT
- Implement the setpoint changes in accordance with FTI-B0010 within the Tech Spec Action Time(s)
- Reduce power to ≤ 38% within the Tech Spec Action Time(s)

3.0 T.S. affected when feedwater heaters are removed from service causing a reduction in feedwater temperature

- T.S. 3.3.1.1, RPS Instrumentation Channels A, B, C, D, E, F, G, and H for Turbine Stop Valve Closure, Table 3.3.1.1-1, Function 9.
- T.S. 3.3.1.1, RPS Instrumentation Channels A, B, C, and D for Turbine Control Valve Fast Closure, Trip Oil Pressure-Low. Table 3.3.1.1-1, Function 10.
- T.S. 3.3.2.1, Control Rod Block Instrumentation for Rod Withdrawal Limiter (RWL) Table 3.3.2.1-1, Function 1.a. Control Rod movement is prohibited with a RWL channel inoperable.
- T.S. 3.3.4.1, End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation.

PERRY NUCLEAR POWER PLANT		Instruction Number: SOI-N21 Section 6.2	
Title: CONDENSATE SYSTEM		Use Category: In Field Reference	
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6.2 Securing Flow to the Hot Surge Tank

☐	6.2.1	**CONFIRM** the Reactor Feedwater Booster pumps are **NOT** in operation.	
☐	6.2.2	**CONFIRM** the Alternate Hot Surge Tank Level Control is **NOT** in effect.	
☐	6.2.3	**CONFIRM** the 1N21-F220 VLV POSIT indicates closed.	1N21-R709
☐	6.2.4	**PLACE** the HOT SURGE TANK LEVEL CONTROL 1N21-F230 in MANUAL on 1H13-P680.	1N21-R475
☐	6.2.5	**CLOSE** HOT SURGE TANK LEVEL CONTROL valve 1N21-F230.	1N21-R475
☐	6.2.6	**CLOSE** the Hot Surge Tank LCV Outlet Isol Valve.	1N21-F541
☐	6.2.7	**REFER TO** SOI-N27 and **VERIFY** RFP Seal Injection Pumps Shutdown.	
☐	6.2.8	**CLOSE** the RFBPs Seal Wtr Supp Press Reg Inlet Isol.	**1N27-F800**
☐	6.2.9	**CLOSE** the RFBPs Seal Wtr Supp Press Reg Disch Bypass.	**1N27-F802**

END OF SECTION