U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos:	50-387, 50-388
Report Nos:	50-387/99-301, 50-388/99-301.
License Nos:	NPF-14, NPF-22
Licensee:	Pennsylvania Power and Light Company
Facility:	Susquehanna Steam Electric Station
Location:	Berwick, Pennsylvania
Dates:	May 10 through 28, 1999
Chief Examiner:	Larry E. Briggs, Senior Operations Engineer
Examiners:	John Caruso, Operations Engineer Rene Vogt-Lowell, Operations Engineer, NRR
Approved By:	Richard J. Conte, Chief Human Performance and Emergency Preparedness Branch Division of Reactor Safety

EXECUTIVE SUMMARY

Susquehanna Steam Electric Station
Examination Report Nos. 50-387/99-301 and 50-388/99-301

<u>Operations</u>

Four instant SRO and one upgrade SRO applicants were administered initial licensing exams. Three applicants successfully passed all portions of the exam. Two applicants did not pass the written examination.

One performance problem exhibited by the applicants was identified concerning their knowledge of the function of the safety/relief valve (SRV) bellows and what affect its failure has concerning subsequent SRV function and operability.

Overall, the as-submitted written examination met the guidance of NUREG 1021. Only two questions required more than minor revision; however, subsequent analysis by the licensee resulted in comments, concerning technical subject matter, for 8 questions (see Attachments 1 and 2).

The JPM set developed by the licensee met the guidance of NUREG 1021.

Scenarios submitted were acceptable with one exception. The third scenario required the addition of an instrument failure that required operator action to prevent plant degradation, to meet the guidance of NUREG 1021.

Report Details

I. Operations

O3 Operations Procedures and Documentation

As a result of the examiners review of material developed or used in the administration of the initial examination process, the examiners observed implementation and related adequacy of facility procedures.

No procedural deficiencies were identified during the performance of the examinations.

05 Operator Training and Qualifications

05.1 Reactor Operator and Senior Reactor Operator Initial Exams

a. Scope

The NRC examiners reviewed the written and operating initial examinations submitted by the facility staff to ensure that they were prepared and developed in accordance with the guidelines of the "Examination Standards for Power Reactors" (NUREG-1021, Interim Revision 8). The review was conducted both in the Region 1 office and at the Susquehanna facility. On May 10-13, 1999, the NRC examiners administered the operating portion of the exam to all applicants. On May 7, 1999, the written exams were administered by the facility's training organization. Grading was completed on May 28, 1999.

b. Observations and Findings

Grading and Results

The results of the exams are summarized below:

	SRO Pass	Fail
Written	3	2
Operating	5	0
Overall	3	2

Attachment 1 provides the NRC staff resolution of facility post-examination comments.

Attachment 2 provides the facility's post examination comments.

Examination Preparation and Quality

The written exams, job performance measures (JPMs) and simulator scenarios were developed by the facility and their contractor representative using the guidelines of the examination standards. The exam development team was comprised of training and operations representatives. All individuals signed onto a security agreement once the

development of the exam commenced. The NRC subsequently reviewed and validated all portions of the proposed exams. Some changes and/or additions to the proposed exams were requested by the NRC prior to and during the on-site review. Personnel subsequently incorporated the agreed to comments and finalized the exams.

The NRC review of the written examination resulted in the significant revision of only two questions. No questions required replacement. Several changes were also made to question stems to make the question easier to understand and to distractors to make them more plausible.

There were no JPMs replaced as a result of NRC review. There were several changes to JPM questions to enhance the level of difficulty and several open reference questions were changed to closed reference.

Written Test Administration and Performance

The facility training department performed an analysis of questions missed on the written exam for generic and individual weaknesses. There were 16 questions that were missed by more than 50 percent of the applicants. Discussions with the licensee indicate that these questions' subject areas will be discussed with all applicants prior to assumption of any licensed duties. The licensee's action was determined to be acceptable.

As a result of the licensee's analysis, comments concerning answer changes and multiple correct answers were provided to the NRC for evaluation and resolution for 8 or the 16 questions. The licensee's comments are detailed in Attachment 2 of this report. The NRC resolution is discussed in Attachment 1.

Operating Test Administration and Performance

During the preparation week one scenario required the addition of an instrument failure that would require operator actions to prevent plant degradation, as detailed in the examination standards, NUREG 1021, Interim Revision 8.

The applicants demonstrated satisfactory communications and teamwork during the simulator exercises in both the routine and emergency portions of the exercise. Briefings were routinely conducted by the candidates when in the control room supervisor position. The briefings were well controlled and ensured that all personnel knew the plant (simulator) status.

c. Conclusions

Four instant SRO and one upgrade SRO applicants were administered initial licensing exams. Three applicants successfully passed all portions of the exam. Two applicants did not pass the written examination.

One performance problem exhibited by the applicants was identified concerning their knowledge of the function of the safety/relief valve (SRV) bellows and what affect its failure has concerning subsequent SRV function and operability.

Overall, the as-submitted written examination met the guidance of NUREG 1021. Only two questions required more than minor revision; however, subsequent analysis by the licensee resulted in comments, concerning technical subject matter, for 8 questions (see Attachments 1 and 2).

The JPM set developed by the licensee met the guidance of NUREG 1021.

Scenarios submitted were acceptable with one exception. The third scenario required the addition of an instrument failure that required operator action to prevent plant degradation, to meet the guidance of NUREG 1021.

O8 Miscellaneous Operations Issues

During a review of the candidates' applications, the examiners determined that: 1) the candidates had performed the required number of significant reactivity control manipulations; 2) the candidates met eligibility guidelines of NUREG 1021 and Reg. Guide 1.8 as applicable; and 3) the licensing basis documents for eligibility requirements (i.e., the Quality Assurance Plan, Technical Specifications, the Final Safety Analysis Report, and the licensed operator program requirements as accredited) were consistent. The licensee is committed to Regulatory Guide 1.8, Revision 2, 1975.

The eligibility requirements of one senior reactor operator instant (SROI) applicant were reviewed. The NRC determined that the eligibility requirements were met for the SROI reviewed.

V. Management Meetings

X1 Exit Meeting Summary

On June 3, 1999, the Chief Examiner discussed the observations along with findings and conclusion of the examination group from the exams with Susquehanna's operations and training management representatives via telephone.

Exam results were provided at that time.

The Chief Examiner also expressed appreciation for the cooperation and assistance that was provided during both the preparation and exam week by the licensee's examination team.

Since there were no observed discrepancies between the simulator and the plant, none were discussed at the exit meeting or in this report.

Attachments:
1. NRC Resolution of Facility Comments
2. Facility Comments on the Written Examination
3. SRO Written Exam w/Answer Key

PARTIAL LIST OF PERSONS CONTACTED

FACILITY

K. Chambliss	Manager, Nuclear Operations
R. DeVore	Simulator Instructor
A. Fitch	Supervisor, Operations Instruction
M. Jacopetti	Simulator Instructor
H. Palmer	Manager Nuclear Training
J. Radishofski	Operations Supervisor

NRC

L. Briggs	Senior Operations Enginéer
J. Caruso	Operations Engineer
R. Vogt-Lowell	Operations Engineer, NRR

Attachment 1

NRC RESOLUTION OF FACILITY COMMENTS

SRO Examination

Licensee comments in Attachment 2

Question 7: Summary of licensee's comment: Correct answer is "b" not "d" as initially indicated, based on testing on the plant reference simulator and the references identified on the review version of the question.

NRC response: Accept licensee's comment. Answer key changed to reflect "b" as the correct answer.

Question 76: Summary of licensee's comment: Correct answer is "a." For the stated conditions, level will not get to -38 inches so recirculation pumps will not trip. Procedure ON-100-109, Section 4.9 tells the operator to ensure Recirculation Pumps are at the minimum speed.

NRC response: Accept licensee's comment. Reviewed applicable portion of referenced procedure. Answer key changed to reflect "a" as the correct answer. The NRC also thinks that under certain accident or fire conditions there could be a loss of recirculation pumps and the cooling medium would be via natural circulation as stated in distractor "d."

The answer key was changed to accept either "a" or "d" as correct.

Question 86: Summary of licensee's comment: Correct answer is "a." The SRV relief setting of about 1200 psi would discharge into the suppression pool with a back pressure of about 75 psi, this would give a starting temperature of about 305F, making "a" the correct answer.

NRC response: Detailed review of the Mollier Diagram and the distractors for this question indicated that about 305F was the correct starting temperature for this question but the second half of the "a" distractor was incorrect because tailpipe temperature following initial lifting of the SRVs will increase until the reactor system pressure blows down to 500 psi then it will decrease with reactor system pressure. This occurs due to the isoenthalpic throttling process of the SRV.

There was no correct answer to question 86 therefore this question is being deleted.

Question 53: Summary of licensee's comment: Answers "a" or "b" should be accepted as correct. OI-AD-013, Section 4.1.5.e directs the fire watch to step in and step out to check for fires (answer "a"). However high rad areas are locked and would require HP to go with the fire watch (answer "b").

NRC response: A review of NDAP-00-0626, indicates that high radiation areas that have doors should be locked. In addition OI-AD-013, the procedure directing fire watch activities directs (by footnotes) the fire watch to have HP support for 6 of 14 listed high rad areas and to feel doors for areas that require a permit to enter (4 areas) and to monitor temperatures from the control room for 4 areas. Only two high rad areas allowed the fire watch to step in and step out.

The answer key was changed to indicate answers "a" or "b" as correct.

Question 55: Summary of licensee's comment: Answers "a" and "b" should be accepted for the time allowed to notify state and local agencies of an EAL. The use of the word "identify" is not clear whether it means an emergency condition is identified or an emergency condition has be identified and classified. Depending on interpretation the time allowed is either 15 minutes or 30 minutes.

NRC response: Agree with the licensee's comments. Both answers "a" and "b" are correct. The answer key was changed to reflect answers "a" or "b" as correct.

Question 63: Summary of licensee's comment: Accept answers "b" or "d" as correct. A review of EDG electrical prints and testing on the plant reference simulator verified that the diesel generator will mechanically trip making "b" correct. The licensee also states that procedural steps in ON-102-640 would be taken that would also make answer "d" correct.

NRC response: Partially accept licensee's comments. Although procedure ON-102-640 does direct action as stated in the question's "d" distractor it is action for a loss or the 125 VDC bus when a diesel is not running to prevent an undesired start. The EDG in this case had a valid start signal and lost the 125VDC bus 1D644 causing it to trip.

The answer key was changed to accept "b" as the only correct answer.

Question 82: Summary of licensee's comment: Accept answers "a" or "d" as correct. "The unit of instruction, SY017 C-4, Automatic Depressurization System, indicates that flow will be too low to register on the acoustic monitors at this low pressure." The licensee agrees that the original answer, "d" was also correct.

NRC response: Do not agree with answer "a" being correct. As stated in the licensee's comment, the flow would be too low to register on the acoustic monitor at the low pressure stated in the stem of the question. Distractor "A" states "SRV "Open" position indication from the Acoustic Monitor will be lost as discharge

downcomer flow lowers." Answer "a" indicates that the acoustic monitor indicated the SRV opened then lost indication as pressure decreased, which would not be the case as indicated in the licensee's comments. The open indication would never have been received making answer "a" incorrect.

The answer key was not changed for this question.

Question 87: Summary of licensee's comment: Accept answers "c" or "d" as correct. The licensee's comments indicate that if suppression pool temperature exceeds 110F then the plant must be placed in cold shutdown (mode 4) and therefore would be less than 110F prior to entering mode 2.

NRC response: Do not agree with the licensee's statement that the plant must be placed in cold shutdown. This statement is true only if pool temperature remains equal to or greater than 110F and cannot be reduced.

However the NRC does agree that the suppression pool must be less than 110F prior to entering mode 2 even if the plant was not placed in cold shutdown because it went to hot shutdown (mode.3) when the mode switch was placed in shutdown and the suppression pool must be less than 110F prior to the mode switch being placed in startup (mode 2).

The answer key was changed to indicate that "c" and "d" are correct answers.

Attachment 2

FACILITY COMMENTS ON THE WRITTEN EXAMINATION

May 12, 1999

1999 NRC WRITTEN EXAM REVIEW

A preliminary review of the written exam using the submitted answer key indicated 16 questions that should be reviewed. Those questions have been reviewed by two licensed operator training staff members. The following changes should be made to the answer key.

The following corrections should be made to the answer key:

Question # 7 The answer key is corrected to "b". The listed references support this answer. The situation was run on the simulator with the indicated result. The candidates were trained using the simulator.

Question # 76 The answer key is corrected to "a". ON-100-009 Section 4.9.8 has the operator ensure the Reactor Recirculation pumps are in service at minimum speed. Level would never get to -38", so the pumps would not trip.

Question # 86 The answer key is corrected to "a". Since the SRV's lifted on their safety setting and all of them lifted, the highest setting (1205 psi) was used. The SY017 C-4, Automatic Depressurization System unit of instruction gives the pressure sets. A science unit SC023 D-8 on steam throttling indicates a back pressure of about 75 psi would be experienced at the tail pipe elements. Using the Mollier Chart, this gives a starting temperature of about 305 °F, making "a" the correct answer.

The following questions have been determined to have two correct answers:

Question # 53 Answers "a" or "b" should be accepted. The OI-AD-013 section 4.1.5.e states that in a high rad area, the fire watch should step in and step out. This makes "a" correct. However, a high rad area is locked and HP is required to open the lock. So HP is required to go with the fire watch when the tour is performed. This makes "b" a correct answer also. The Site Fire Protection Engineer was called and stated that keys are NOT issued to fire watches which means that HP is required to accompany the fire watch.

Question # 55 Answers "a" or "b" should be accepted. The question is unclear as to whether the situation has been classified. The confusion comes with the use of the word "identify". The procedure uses the words "identify" and "verify". With this interpretation, the conditions are identified and 15 minutes is used to classify the situation based on these conditions. Then 15 minutes is used to notify the authorities. This gives a total of 30 minutes or answer "b". A second interpretation is that the condition being "identified" means that the operator realizes that an emergency condition exists. He has classified it. Only 15 minutes to notify are left. This makes "a" a correct answer.

Question # 63 Answers "b" or "d" should be accepted. Not all protective trips are lost on loss of DC. The mechanical overspeed trip and the pneumatic trips are still functional. Also the shutdown solenoid deenergizes and causes the diesel to trip on loss of DC. This was verified by running the transient in the simulator. The loss of control power will prevent the breaker from operating making "b" correct. Immediately after the loss of DC control power, the change suggested by "d" should be done so that the diesel can be controlled. ON-102-640 directs this.

Question # 82 Answers "a" or "d". The unit of instruction SY017 C-4, Automatic Depressurization System, indicates that flow will be too low to register on the acoustic monitors at this low pressure. This makes "a" correct. The suppression pool static head may also cause water to begin to come back into some of the spargers and then downcomers. This can be considered as reflooding making "d" correct.

Question # 87 Answers "c" or "d" should be accepted. Tech Specs 3.6.2.1 states that with a temperature > 110 °F, you must be in mode 4. So you need to be < 110 °F before going into Mode 2. This makes answer "c" correct. The same Tech Spec also states that you must be < 90 °F before exceeding the point of adding heat. So answer "d" is also correct.

These are the changes that should be made on the basis of the exam analysis.

Submitted: Russell B DeVore

Approved: Arthur S Jr Supv - Ops Ins

Attachment 3

SRO WRITTEN EXAM W/ANSWER KEY

U.S. Nuclear Regulatory Commission
Site-Specific
Written Examination

Applicant Information

Name:	Region: I
Date: 5/10/99	Facility: Susquehanna
License Level: SRO	Reactor Type: GE
Start Time:	Finish Time:

Instructions

Use the answer sheets provided to document your answers. Staple this cover sheet on top of the answer sheets. The passing grade requires a final grade of at least 80.00 percent. Examination papers will be collected four hours after the examination starts.

Applicant Certification

All work done on this examination is my own. I have neither given nor received aid.

____
Applicant's Signature

Results

Examination Value	________ Points
Applicant's Score	________ Points
Applicant's Grade	________ Percent

PART B - WRITTEN EXAMINATION GUIDELINES

1. *[Read Verbatim]* After you complete the examination, sign the statement on the cover sheet indicating that the work is your own and you have not received or given assistance in completing the examination.

2. To pass the examination, you must achieve a grade of 80.00 percent or greater. Every question is worth one point.

3. For an initial examination, the time limit for completing the examination is four hours.

   For a requalification examination, the time limit for completing both sections of the examination is three hours. If both sections are administered in the simulator during a single three-hour period, you may return to a section of the examination that was already completed or retain both sections of the examination until the allotted time has expired.

4. You may bring pens and calculators into the examination room. Use only black ink to ensure legible copies.

5. Print your name in the blank provided on the examination cover sheet and the answer sheet. You may be asked to provide the examiner with some form of positive identification.

6. Mark your answers on the answer sheet provided and do not leave any question blank. Use only the paper provided and do not write on the back side of the pages. If you decide to change your original answer, draw a single line through the error, enter the desired answer, and initial the change.

7. If the intent of a question is unclear, ask questions of the NRC examiner or the designated facility instructor only.

8. Restroom trips are permitted, but only one applicant at a time will be allowed to leave. Avoid all contact with anyone outside the examination room to eliminate even the appearance or possibility of cheating.

9. When you complete the examination, assemble a package including the examination questions, examination aids, answer sheets, and scrap paper and give it to the NRC examiner or proctor. Remember to sign the statement on the examination cover sheet indicating that the work is your own and that you have neither given nor received assistance in completing the examination. The scrap paper will be disposed of immediately after the examination.

10. After you have turned in your examination, leave the examination area as defined by the proctor or NRC examiner. If you are found in this area while the examination is still in progress, your license may be denied or revoked.

11. Do you have any questions?

Senior Reactor Operator Answer Sheets

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Senior Reactor Operator Answer Sheets

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1. Given the following conditions:

- Unit 1 was operating at 100% power
- Following a valid reactor scram signal the Reactor Protection System was unable to de-energize the 185 individual Scram Pilot Valves
- The Backup Scram Valves did function as designed and all control rods fully inserted

Which of the following would be an indication that the Backup Scram Valves actually accomplished the scram?

a. No hydraulic control unit accumulator fault alarms would be received on the full core display.

b. The total elapsed time from the scram signal to all control rods fully inserted would be noticeably longer.

c. The Scram Discharge Volume Vent and Drain Valves would not reposition.

d. The individual control rod scram speeds would be slower.

2. Given the following CURRENT full core display parameters for control rod 22-35 that had been at Notch "48".

- Full-In:	Illuminated
- Full-Out:	NOT Illuminated
- Drifting:	Illuminated
- Selected:	NOT Illuminated
- Accumulator:	NOT Illuminated
- Scram Valves:	NOT Illuminated

These conditions are the result of:

a. the Scram Inlet Valve (126) opening.

b. the Scram Outlet Valve (127) opening.

c. the Scram Inlet Valve (126) and Scram Outlet Valve (127) both opening.

d. the control rod being driven to Notch "00" using the "Insert Rod" pushbutton.

Given the following conditions:

- Control rod withdrawals for a Unit 2 reactor startup are in progress
- The Unit PCO is withdrawing control rods to Notch "48" using the Continuous Rod Withdrawal and Withdraw Rod pushbuttons
- When control rod 18-19 is withdrawn the following are received
  - Rod Overtravel alarm
  - Rod position indicates "--"

Which of the following is the cause of these indications?

a. The Reactor Manual Control System Rod Motion Timer has malfunctioned resulting in an "overtravel" condition.

b. The PCO provided a withdraw signal to the rod for an excessive period of time after reaching Notch "48".

c. The control rod drive mechanism is at the "overtravel" position but control rod position is currently unknown.

d. The rod has drifted beyond the last even numbered Notch and is still settling back to Notch "48".

Given the following conditions:

- Control rod withdrawals for a Unit 1 reactor startup are in progress
- The current Rod Worth Minimizer (RWM) group is Group 1
- Group 1 contains 12 control rods that are to be withdrawn from Notch "00" to Notch "48"
- The first 10 rods have been withdrawn to Notch "48" and the remaining 2 rods to Notch "44"
- A control rod in Group 2 has been selected but NOT withdrawn

For these conditions the RWM will display:

a. two withdraw errors and if a third withdraw error is made further rod withdrawals will be blocked except for the three rods with the withdraw errors.

b. two withdraw errors and further rod withdrawals will be blocked except for the rods with the withdraw errors.

c. two insert errors and if a third insert error is made, further rod withdrawals will be blocked except for the three rods with the insert errors.

d. two insert errors and further rod withdrawals will be blocked except for the rods with the insert errors.

Given the following conditions:

- Unit 1 was operating at 80% power
- A logic failure has resulted in the "B" Recirculation Pump running back to the #2 Limiter
- Actual #2 Limiter Runback conditions do NOT exist

Which of the following describes the plant limitations required while operating under these conditions?

a. If the "B" Recirculation Pump runback cannot be reset in 2 hours it must be tripped within the next 12 hours.

b. Single loop operating restrictions and limitations must be in place within 2 hours.

c. The "B" Recirculation Pump runback must be reset and speed raised or the "A" Pump speed reduced to 45% within 2 hours.

d. Mismatched loop flow operation is not permitted and immediate action must be taken to be in Mode 3 within 12 hours.

6. Given the following conditions:

- Unit 2 is making preparations for a reactor and plant startup
- Reactor temperature is 120 degrees F
- The reactor is at atmospheric pressure
- The Condensate and Feedwater Systems are in Long Path Recirculation
- Reactor Water Cleanup is operating for reactor water level control

Following the start of the Reactor Recirculation Pumps, what is the MAXIMUM speed at which they can be operated for these conditions?

a. 20%

b. 30%

c. 40%

d. 45%

Given the following conditions:

- Both Units are operating at 100% power
- Unit 2 has Suppression Pool cooling in service on the "A" Residual Heat Removal (RHR) Pump
- A loss of DC power to the Unit 1 RHR Division 1 logic has occurred
- While troubleshooting is in progress a valid loss of coolant accident signal is received on Unit 1

Which of the following describes the expected impact on BOTH Unit's RHR systems?

a. The Unit 1 "B" RHR Loop will start and inject normally. The Unit 1 "A" RHR Loop must be manually started and aligned for injection. The Unit 2 "A" RHR Pump will trip.

b. The Unit 1 "B", "C" and "D" RHR Pumps will start with injection via both RHR Loops. The Unit 2 "A" RHR Pump will automatically trip then the Unit 1 "A" RHR Pump will start.

c. The Unit 1 "B" RHR Loop will start and inject normally. The Unit 1 "A" RHR Loop must be manually started and aligned for injection. The Unit 2 "A" RHR Pump must be manually tripped.

d. The Unit 1 "B", "C" and "D" RHR Pumps will start with injection only via the "B" RHR Loop. The Unit 2 "A" RHR Pump must be manually tripped then the Unit 1 "A" RHR Pump will start.

8. Given the following conditions:

- Following a transient, Unit 1 is operating in accordance with EO-100-102, "RPV Control"
- The Pressure Control Leg has directed the use of Reactor Water Cleanup (RWCU) in the Blowdown Mode
- ES-161-001, "RWCU Blowdown Mode Bypassing Interlocks", has been implemented
- Moments after placing RWCU in the Blowdown Mode, a "RWCU System High Leakage" alarm is received and is present for greater than 60 seconds

Select the required operator actions for these conditions assuming RWCU responds as expected.

a. Verify automatic closure of the Inboard and Outboard Isolation Valves (F001 and F004).

b. Verify automatic closure of the Blowdown Flow Regulator Valve (F033).

c. Verify automatic closure of the Inboard and Outboard Isolation Valves (F001 and F004) and the Blowdown Flow Regulator Valve (F033).

d. Manually close the Inboard and Outboard Isolation Valves (F001 and F004) and verify automatic closure of the Blowdown Flow Regulator Valve (F033).

. Given the following conditions:

- Unit 2 is in Mode 4 with Shutdown Cooling in service on the "B" Residual Heat Removal (RHR) loop
- A large leak has developed just upstream of the Shutdown Cooling Suction Outboard Isolation Valve (F008)
- Reactor water level rapidly reaches the Low Pressure Coolant Injection (LPCI) initiation setpoint
- All expected actions occur
- Core Spray is NOT available

Which of the following describes the expected affect on the leak and reactor water level for these conditions?

a. The leak will be stopped and reactor water level will stabilize but not recover unless operator action is taken to inject.

b. The leak will NOT be stopped. Operator action is required to isolate the leak and inject with RHR to recover level.

c. The leak will be stopped and reactor water level will rise due to the "B" Loop of RHR injecting in the LPCI mode.

d. The leak will NOT be stopped. Operator action is required to isolate the leak allowing automatic LPCI injection to recover level.

10. Given the following conditions:

- The Unit 1 High Pressure Coolant Injection (HPCI) system is running in the CST to CST mode
- The Flow Controller is in "Automatic" set for 3500 gpm
- System flowrate is 3500 gpm
- The Extra PCO reports that HPCI turbine speed is lowering

Which of the following would cause this response?

a. A relay failure has just transferred the Flow Controller from "Automatic" to "Manual"

b. The HPCI Test Line To CST Isolation Valve (F011) has just auto closed.

c. The HPCI ramp generator output just failed to its "low" limit.

d. The HPCI Minimum Flow To Suppression Pool Valve (F012) has just opened.

Which of the following High Pressure Coolant Injection (HPCI) "support" systems/components, if Inoperable, would NOT affect the Operability of HPCI?

a. Standby Gas Treatment System

b. The Auxiliary Oil Pump

c. The Suppression Pool

d. The Condensate Storage Tank

12. Which of the following conditions MUST be met when the “A” Core Spray loop suction is lined up to the Condensate Storage Tank (CST)? Assume the Unit CSTs are NOT cross-connected.

a. The reactor vessel head must be removed and the core defueled.

b. The "A" Core Spray loop must be declared Inoperable.

c. The Unit Condensate Storage Tank level must be greater than 49%.

d. The opposite Units' Condensate Storage Tank must remain available.

3. Given the following conditions:

- Unit 2 has experienced a failure-to-scram (ATWS)
- The Standby Liquid Control (SLC) system was initiated and injected for 52 minutes before both SLC Pumps failed
- Reactor power is in the source range

How does this failure affect the planned reactor cooldown and depressurization?

a. Boron concentration is sufficient to allow a complete cooldown under any plant conditions.

b. Cooldown can be accomplished if completed before Xenon decays out of the core.

c. Boron concentration is sufficient to allow a complete cooldown with a maximum of 8 control rods not fully inserted.

d. Reactor Engineering must make the determination if current boron concentration will allow a complete cooldown.

Given the following conditions:

- Unit 1 is operating at 100% power
- The "B" Standby Liquid Control (SLC) Pump was declared "Inoperable" 4 days ago
- The "Loss Of Continuity To Squib Valves" alarm has just been received
- Investigation reveals broken leads to the "A" SLC Squib Valve primers
- The "B" SLC Squib Valve primer continuity status has not changed

Select the required actions for these conditions.

a. Restore one subsystem to Operable status in 8 hours or be in Mode 3 within the next 12 hours.

b. Continue in the 7 day Required Action for one Inoperable subsystem, no further actions are required.

c. Enter a 7 day Required Action for the "A" SLC Subsystem, continue in the 7 day Required Action for the "B" SLC Subsystem.

d. Extend the current 7 day Required Action for one Inoperable subsystem not to exceed 10 days from the initial failure to meet the LCO.

Given the following conditions:

- Unit 2 is operating at 60% power
- A valid reactor scram signal occurs on high drywell pressure

Which of the following failures would PREVENT the Backup Scram Valves from venting the scram air header?

a. The solenoid on the upstream Backup Scram Valve (110B) does not de-energize.

b. The Alternate Rod Injection Scram Air Header Block Valves (SV 14799 & 147100) did not close on the scram.

c. Only one Reactor Protection System Trip System de-energized on the scram signal.

d. The check valve (111) bypassing the downstream Backup Scram Valve (110A) does not open.

Given the following conditions:

- Unit 1 is operating at 100% power
- The "B" Reactor Protection System (RPS) MG Set is out of service for extended maintenance
- One of the "A" RPS MG Set Electrical Protection Assembly (EPA) output breaker undervoltage relays has been determined to be Inoperable

Select the required actions.

a. Insert a half scram and remove the "A" RPS MG Set from service within 1 hour.

b. Restore the EPA to Operable status within 72 hours or be in Mode 3 in 12 hours and Mode 4 in 36 hours

c. Transfer the "A" RPS Bus to the alternate power supply within 72 hours.

d. Restore the EPA to Operable status within 1 hour or be in Mode 3 in 12 hours and Mode 4 in 36 hours

17. The following are the current indications on Valve Control Monitor Panel for Channel 1 of the Traversing Incore Probe (TIP) System (see attached figure) :

- Ball Valve "Closed" lights - both illuminated
- Ball Valve "Open" lights - both extinguished
- Shear Valve Monitor Lights - both illuminated
- Squib Monitor lights - both extinguished

Which of the following describes the status of TIP Channel 1's Shear Valves and primary containment integrity?

a. The TIP Shear Valves are inoperable and primary containment integrity is met.

b. The TIP Shear Valves are inoperable and primary containment integrity is not met.

c. The TIP Shear Valves are operable and primary containment integrity is met.

d. The TIP Shear Valves are operable and primary containment integrity is not met.

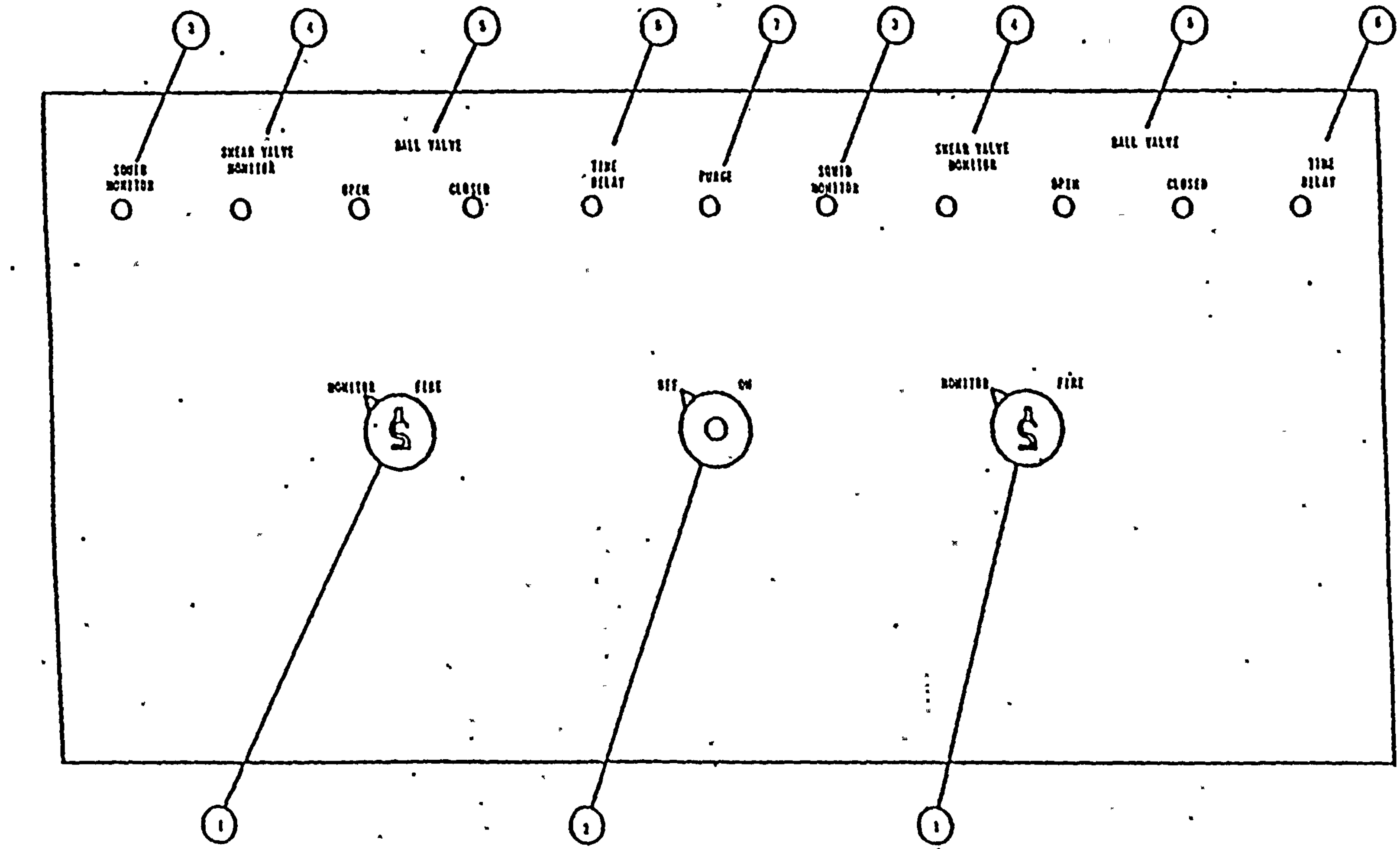


FIGURE 14
DUAL VALVE CONTROL MONITOR

Given the following conditions:

- Unit 2 is at 35% with power ascension in progress
- The "A" Rod Block Monitor (RBM) channel Gain Change Circuit malfunctions and does NOT provide any LPRM input signal gain adjustments
- The "B" RBM channel is bypassed with the "joystick"

How does this malfunction affect the continuing reactor startup?

a. The RBM channel would default to its low trip setpoint and generate a rod withdrawal block.

b. Local power around a withdrawing control rod may reach a higher level before any automatic protective actions occur.

c. The RBM channel would transfer to the alternate Reference APRM allowing continued rod withdrawals.

d. The local power rise during a control rod withdrawal can only be controlled by the RBM Backup Trip Unit.

19. Given the following conditions on Unit 1:

- A reactor startup is in progress with the Reactor Mode Switch in "Startup/Hot Standby"
- All Intermediate Range Monitor (IRM) channels are reading 3/125 on Range 2
- All Average Power Range Monitor (APRM) channels are reading "downscale"
- Both Rod Block Monitor (RBM) channels are reading "downscale"
- The Rod Select Clear pushbutton is illuminated
- All systems are operating as designed

Control rod withdrawals are being prevented by:

a. an RBM rod block.

b. an APRM rod block.

c. a "No Rod Selected" rod block.

d. an IRM rod block.

Given the following conditions:

- Unit 1 is ready to load fuel following a complete core offload (no fuel assemblies are in the core)
- Source Range Monitor (SRM) channels "A" and "C" are Inoperable
- SRM detectors "B" and "D" are fully inserted with count rates of 1.2 cps and 2 cps respectively
- The Signal-To-Noise Ratio for SRM "B" and "D" is 3:1 for both channels

Which of the following describes what is required to commence core reload under these conditions?

a. One of the Operable SRMs must be in the quadrant where core alterations are being performed and the other in an adjacent quadrant. Minimum count rate is not required to be met until 4 fuel assemblies have been installed adjacent to the SRM.

b. SRM "A" or "C" must be returned to Operability to allow core alterations to begin. Minimum count rate is not required to be met until 4 fuel assemblies have been installed adjacent to the SRM.

c. One of the Operable SRMs must be in the quadrant where core alterations are being performed and the other in an adjacent quadrant. A neutron source must be installed adjacent to the SRMs to achieve a minimum 3 cps.

d. SRM "A" or "C" must be returned to Operability and a neutron source must be installed adjacent to the SRMs to achieve a minimum 3 cps to allow core alterations to begin.

21. Given the following conditions:

- Unit 1 is operating at 100% power
- Average Power Range Monitor (APRM) Channel "C" has been bypassed with the joystick for maintenance

A Gain Adjustment for APRM "C" will be required:

a. prior to taking it out of "Bypass".

b. if it differs by more than 2% from the average of the remaining 5 APRM channels.

c. prior to exceeding a gain adjustment factor (AGAF) of 1.00.

d. if its gain adjustment factor (AGAF) is less than 0.98.

Given the following conditions:

- Unit 2 is performing a startup from 180 degrees F
- When the point of adding heat is reached the Unit PCO reports that one of the Wide Range Level indicators has started to lower at a slow but steady rate
- This trend continues as the plant heatup continues
- Drywell pressure and temperature are unchanged
- All other level indicators are steady
- Assume this level indicator has a dedicated reference leg

This level indicator lowering is caused by:

a. the instrument d/p cell equalizing valve leaking by.

b. instrument reference leg outgassing occurring.

c. a rise in Reactor Building ambient temperatures.

d. the instrument reference leg excess flow valve being closed.

23. Given the following conditions:

- Unit 2 is operating at 75% power
- Suppression pool water level is 23.9 feet
- Condensate Storage Tank level is 45.3 inches (13%)
- The Reactor Core Isolation Cooling (RCIC) system is in a normal standby lineup except that the Pump Suction From CST Valve (F010) has just been closed for a stroke test
- While the F010 is closed RCIC receives a valid initiation signal

Selected the expected RCIC system response to these conditions?

a. The Pump Suction From CST Valve (F010) will open allowing RCIC to start and inject normally.

b. The Pump Suction From Suppression Pool Valve (F031) will open allowing RCIC to start and inject normally.

c. RCIC will start, run up to an overspeed condition and then trip.

d. The Steam To RCIC Turbine Valve (F045) will not open due to pump low suction pressure.

Given the following conditions:

- Unit 2 has experienced a loss of off-site power
- The Reactor Core Isolation Cooling (RCIC) system automatically initiated as designed
- The Extra PCO has placed the RCIC Flow Controller in "Manual" to control flow at 350 gpm to maintain reactor water level
- While in these conditions a failure of the shaft driven lube oil pump results in a total loss of oil pressure (reading 0 psig)

Which of the following describes the expected response of RCIC?

a. RCIC will immediately trip on low lube oil pressure.

b. RCIC will decelerate as the governor valve strokes closed.

c. RCIC speed will remain constant until turbine bearing damage begins.

d. RCIC will accelerate and trip on overspeed.

25. Given the following conditions:

- The Automatic Depressurization System (ADS) Manual Initiation pushbuttons "A" and "C" (HS30A and HS30C) have been armed and pressed
- There is no response from the ADS safety relief valves

Which of the following electrical bus failures caused this system response?

a. A loss of 125 VDC Bus 1D624

b. A loss of 250 VDC Bus 1D652.

c. A loss of 125 VDC Bus 1D614.

d. A loss of 250 VDC Bus 1D662.

. Given the following conditions:

- Control Room conditions are such that an evacuation is required
- At the Remote Shutdown Panel, ALL Safety Relief Valve (SRV) Emergency Transfer Switches have been placed in "Emergency"
- Valid Automatic Depressurization System initiation signals and conditions are then received
- No Operator actions are taken

Select the expected automatic SRV response for these conditions.

a. Three SRVs will open.

b. Six SRVs will open.

c. Only the transferred SRVs will open.

d. No SRVs will open

27. Given the following conditions:

- Unit 1 is operating at 50% power
- Main Steam Isolation Valve (MSIV) stroke testing is in progress
- The Inboard MSIV in the "A" steam line did not fully stroke closed

Select the required actions.

a. Verify the "A" steam line Outboard MSIV is operable and continue plant operation indefinitely.

b. Close and deactivate the "A" steam line Outboard MSIV and continue plant operation indefinitely.

c. Close and deactivate the "A" steam line Outboard MSIV within 8 hours and commence a shutdown to be in Mode 4 in 36 hours.

d. Verify the "A" steam line Outboard MSIV is operable within 8 hours and commence a shutdown to be in Mode 4 in 36 hours.

Given the following conditions:

- Unit 2 is shutdown with core alterations in progress
- While a fuel bundle is being raised out of the core the "Normal Up" light illuminates and the fuel hoist stops
- The Fuel Grapple position indicator (Z) reads 20
- The expected "Normal Up" position should be 16

Which of the following describes the use of the "Hoist Override" pushbutton for these conditions?

a. Hoist Override may be used to raise the grapple only to the "Normal Up" position of 16 with Refueling SRO explicit permission.

b. With the refueling bridge over the core, the Hoist Override pushbutton is bypassed and is unavailable for use.

c. With irradiated fuel on the hoist use of the Hoist Override pushbutton is procedurally prohibited.

d. Hoist Override may be used for raising the grapple one "Z" direction increment at a time if a second licensed operator is available for concurrent position verification.

. Given the following conditions:

- Unit 1 is performing a reactor startup and heatup
- The reactor is critical and pressure is 150 psig
- Instrument air was lost to the Outboard Main Steam Isolation Valves (MSIV) and they drifted closed
- All expected automatic actions occurred but NO operator actions were taken
- Instrument air has just been restored and the air header has repressurized

Which of the following is the expected response of the Outboard MSIVs and the reason for that response?

The MSIVs will:

a. reopen as soon as instrument air has repressurized the lines, the accumulators and the valve actuators.

b. remain closed until the control switches are placed in "Close" and the NSSSS Isolation reset push-buttons (Div I and II) are pressed.

c. reopen as soon as both of the valve pneumatic control solenoids on each MSIV are reenergized.

d. remain closed because the differential pressure across the valve will prohibit opening without equalization.

30. Given the following conditions:

- Unit 2 has experienced a closure of all Main Steam Isolation Valves from 100% power
- Reactor pressure control is via manual Safety Relief Valves (SRV) operation to maintain pressure less than 965 psig

Which of the following is a direct indication that both of the discharge line vacuum breakers on a single SRV have failed "open" for these conditions?

a. SRV tail pipe temperatures are abnormally high for current plant conditions.

b. Plant parameter limits requiring RPV Flooding may be reached sooner than anticipated.

c. The Suppression Chamber to Drywell vacuum breakers are cycling each time the SRV is opened and then closed.

d. Plant parameters may exceed the Heat Capacity Temperature Limit curve earlier than expected.

D. Which of the following describes how the main turbine is protected from overspeed conditions if the generator output breaker trips open at 30% power? (See attached figure.)

The Electro-Hydraulic Control (EHC) system:

a. load reject circuit will initiate a fast closure of the Intercept Valves.

b. power/load unbalance circuit will initiate a fast closure of the Turbine Control Valves.

c. load reject circuit will throttle the Intercept Valves closed.

d. power/load unbalance circuit will throttle the Turbine Control Valves closed.

32. During a Unit 1 startup and heatup in accordance with GO-100-002, "Plant Startup, Heatup And Power Operation", the operator is directed to maintain turbine first stage pressure less than 120 psig during shell warming.

Which of the following would be expected to occur if this value is exceeded?

a. Main turbine Exhaust Hood Spray initiates.

b. Reactor scram.

c. Main turbine overspeed trip

d. Main Steam Isolation Valve closure.

33. Given the following conditions:

- Unit 1 experienced a reactor scram from 95% power
- Reactor water level reached 0 inches
- Feedwater level control remained in "Automatic" and reactor water level currently at +5 inches and is rising
- The Unit PCO has pressed the "Level Setpoint Setdown" pushbutton (HS-C32-1S08)
- All plant systems responded as designed

Reactor water level will:

a. return to +35 inches.

b. stabilize at +5 inches.

c. rise to +13 inches

d. stabilize at +18 inches

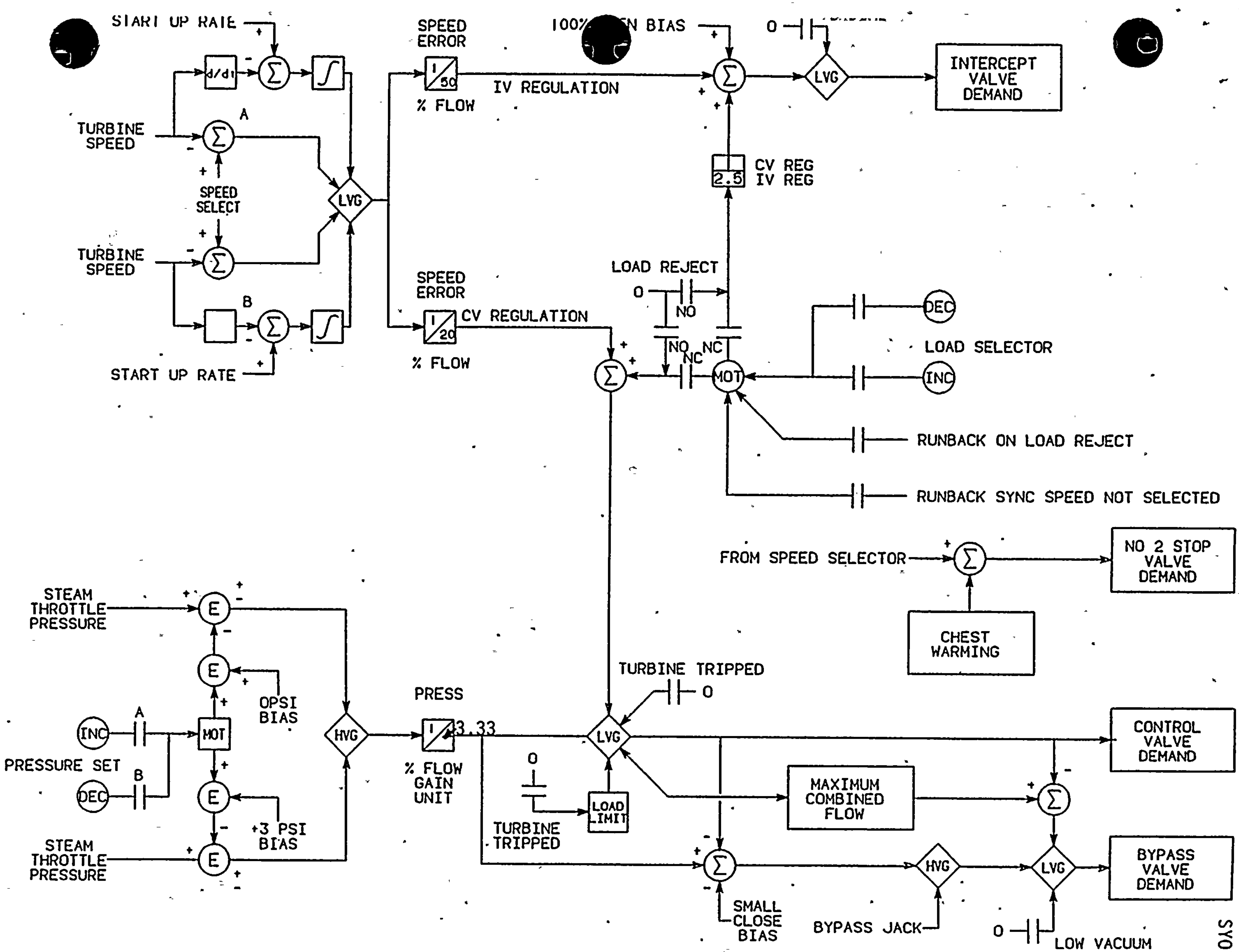


FIGURE 8
SPEED AND ACCELERATION CONTROL UNIT

SY017 A-8

. Given the following conditions:

- Both Units are operating at 100% power
- The Standby Gas Treatment System (SGTS) is in a normal, standby lineup
- A valid Unit 1 SGTS system initiation signal on high drywell pressure is received

Which of the following is the location from which SGTS will AUTOMATICALLY take suction for these conditions?

SGTS will begin to process the:

a. High Pressure Coolant Injection Barometric Condenser Vacuum Pump discharge.

b. drywell atmosphere via the drywell and suppression chamber purge connections.

c. discharge flow from the running Reactor Building Ventilation Exhaust Fans.

d. drywell atmosphere via the drywell vent connections.

35. Given the following conditions:

- Both Units are operating at 100% power
- All Startup Bus power sources are available
- All four Diesel Generators are available
- The Normal Source Breaker (1A201-01) to ESS Bus 1A is opened with its handswitch on Panel 0C653
- No other operator actions were taken

Which of the following describes what must occur to reenergize the ESS 1A Bus assuming all systems operate as designed?

a. The "A" Diesel Generator will start and the Emergency Source Breaker (1A201-04) will automatically close.

b. The Alternate Source Breaker (1A201-09) will automatically close.

c. The PCO will have to start the "A" Diesel Generator and close the Emergency Source Breaker (1A201-04).

d. The PCO will have to close the Alternate Source Breaker (1A201-09).

The Unit 1 Unit Supervisor is reviewing the following surveillance data on the 125 VDC 1D640 Battery with the Unit at 100% power:

- Maximum pilot cell specific gravity - 1.215
- Minimum pilot cell specific gravity - 1.205
- Maximum battery cell specific gravity - 1.217
- Minimum battery cell specific gravity - 1.176
- Average battery cell specific gravity - 1.208
- Electrolyte levels in all cells are within limits
- Float voltages in all cells are within limits

What is MAXIMUM permissible time Unit 1 may remain at power for these conditions?

a. 2 hours

b. 12 hours

c. 14 hours

d. 31 days

7. At the "C" Diesel Generator Local Control Panel the Control Mode Select switch has been placed in "Local".

Which of the following describes the operational status of the "C" Diesel Generator?

The "C" Diesel Generator:

a. must be manually started by the local operator on either a loss of off-site power or a LOCA signal.

b. will automatically start on a loss of off-site power but the output breaker for the associated bus will not automatically close.

c. must be manually started by the local operator and the output breaker locally closed on a loss of off-site power.

d. will automatically start in response to both a loss of off-site power and a LOCA signal but load sequencing will not occur.

Given the following conditions:

- Unit 2 is operating at 55% power with the "C" Main Steam Line (MSL) isolated (Inboard and Outboard MSIVs are closed)
- A fuel failure results in rising main steam line radiation levels

Which of the following describes the Main Steam Line Radiation Monitor automatic MSIV closure functions under these conditions?

a. With the "C" MSL MSIVs closed, the "C" MSL Rad Monitor signal is removed from the circuitry and the isolation logic is modified to a one-out-of-three to close the remaining 6 MSIVs.

b. The physical location of the 4 MSL Rad Monitors allows each of them to "see" all four steam lines providing for a normal MSIV closure based upon rad levels in the operating steam lines.

c. With the "C" MSL MSIVs closed, the "C" MSL Rad Monitor will have a "downscale" signal present providing one of the two required "trips" for the isolation.

d. The physical location of the 4 MSL Rad Monitors upstream of the Inboard MSIV provides for continued monitoring of the "C" MSL even though it is isolated.

39. Given the following conditions:

- Unit 1 is operating at 90% power
- The functional test of the Standby Gas Treatment (SGTS) Fire Suppression System has just been performed
- The test results were UNSATISFACTORY for both SGTS trains

How does this failure impact continued plant operation?

a. Both trains of SGTS are Inoperable. If one cannot be restored to Operable status in 4 hours, the plant must be in Mode 3 within 12 hours.

b. The secondary containment is Inoperable. If one SGTS train cannot be restored to Operable status in 4 hours, the plant must be in Mode 3 within 12 hours.

c. Both trains of SGTS remain Operable with no restrictions on plant operations.

d. A continuous fire watch is required in the area when running either SGTS train.

Given the following conditions on Unit 1:

- MFLPD 0.91
- MFLCPR 0.80
- Reactor power 89%
- Core flow 85%

What are the proper actions for these conditions?

a. Reduce the APRM scram setpoints by a multiple of the RTP/MFLPD ratio.

b. Initiate immediate corrective action to restore LHGR to within limits in 1 hour.

c. Reduce the APRM Gain Adjustment Factor by the ratio of MFLPD/RTP.

d. Initiate immediate corrective action to restore MCPR to within limits in 1 hour.

41. Select the specific plant conditions requiring the Unit 2 Unit Supervisor to assume full responsibility for the plant Common Systems.

a. The Unit 1 Unit Supervisor is out of the Unit 1 "At-The-Controls" area.

b. The Unit 1 Unit Supervisor has assumed the Control Room command function in the absence of the Shift Supervisor.

c. Unit 1 is in an "off-normal" condition requiring Unit Supervisor and Shift Supervisor attention.

d. Unit 1 is shutdown for a scheduled refueling and maintenance outage.

42. Unit 2 has entered LCO 3.0.3 at 1400, May 10, 1999. Preparations for Unit shut down are in progress.

What are the SSES administrative time guidelines for commencing the power reduction?

Power reduction should begin:

a. immediately.

b. not later than 1500.

c. not later than 1700.

d. not later than 1800.

D. Given the following information for a Unit 1 Technical Specification System:

- This System is Inoperable and must be restored to Operable status within 7 days
- If not returned to Operable status within 7 days, this System is required to:
  - -- Be in Mode 3 in 12 hours
    AND
  - -- Be in Mode 4 in 36 hours
- The 7 day return to Operable status requirement expired at 0300 on May 12th
- Unit 1 reached Mode 3 at 0900 May 12th

When is Unit 1 required to be in Mode 4?

a. 0300 May 13th

b. 1500 May 13th

c. 2100 May 13th

d. 0300 May 14th

D4. Prior to placing the Reactor Mode Switch to "Startup/Hot Standby" during a reactor startup, the Shift Supervisor shall notify and obtain approval from the:

a. Supervisor - Reactor Engineering.

b. Operations Supervisor - Nuclear.

c. Manager - Nuclear Operations.

d. General Manager - Susquehanna.

45. During a Unit 1 evolution, a procedure must be removed from its Controlled Manual. The Operations Department Clerk is not available to provide the User Controlled copy required. The copy of the procedure was made at 1300 on May 11, 1999.

Which of the following is the maximum expiration date and time allowed for this procedure WITHOUT requiring User Controlled tracking from the Document Control Center?

a. 1900, May 11, 1999

b. 0700, May 12, 1999

c. 1300, May 12, 1999

d. 1300, May 13, 1999

Given the following conditions:

- Unit 2 is operating at 85% power
- Operations is performing a check-off list on a system with manually operated valves in the drywell
- These valves do not have Control Room indications
- Assume this system is operating normally

The operator is procedurally directed to verify the position of these drywell valves by:

a. obtaining their positions as noted on the most current Status Control Log.

b. referring to the most recently completed check-off list on the system

c. verifying system parameters (flow, pressure, etc.) are as expected for the current plant conditions.

d. noting the inaccessible valves for verification on the next planned or un-planned drywell entry.

47. With Unit 1 operating at power, a status change via procedure revision has been made to the Reactor Water Cleanup (RWCU) system Checkoff List. The RWCU Reactor Bottom Head Drain Bypass Valve (144F103) component numerical identification has been changed.

How this status change is procedurally required to be tracked until the drywell is accessible allowing a new checkoff list lineup to be performed?

The RWCU checkoff list status change shall be:

a. placed on the list for completion at the next scheduled or unscheduled outage.

b. tracked in the Unit 1 Unit Supervisor Turnover Sheet.

c. documented on the most recently completed checkoff list for the system.

d. tracked in the Unit 1 LCO/TRO log.

Given the following information:

- Plant Systems "A" and "B" are required to support the operation of System "C"
- The completion times for restoration of these systems to Operable status are:
  - System "A" - 7 days
  - System "B" - 14 days
  - System "C" - 3 days
- System "A" became Inoperable 4 days ago at 0800
- System "B" became Inoperable today at 0800
- System "A" was restored to Operable status today at 1200

Assuming the "Maximum Out Of Service Time" criteria, when must System "B" be restored to Operable status?

At 0800:

a. 6 days from today.

b. 10 days from today.

c. 14 days from today.

d. 17 days from today.

49. Which of the following individuals has the procedural responsibility to authorize entry into a Unit 2 area with a dose rate of 750 mr/hour for investigation of abnormal equipment vibration WITHOUT a job specific RWP or specific work plan?

a. The on-shift Health Physics Foreman.

b. The Unit Supervisor.

c. The Radiological Operations Supervisor.

d. The Shift Supervisor

Given the following conditions:

- Unit 1 is making preparations for performing a procedure on a system in a radiation area with a 75 mr/hour dose rate
- The appropriate radiological precautions have been taken
- An HP Briefing has been completed

Using the As Low As Reasonably Achievable (ALARA) guidelines, which of the following is the PREFERRED method for completing this procedure?

a. One individual performing the procedure in the area for 70 minutes.

b. Two individuals performing the procedure in the area for 25 minutes.

c. One individual installing shielding in the area for 30 minutes then performing the procedure for 45 minutes with a reduced dose rate of 7.5 mr/hour.

d. Two individuals installing shielding in the area for 10 minutes then both performing the procedure for 25 minutes with a reduced dose rate of 7.5 mr/hour.

51. Given the following conditions:

- A General Emergency has been declared on Unit 1
- It has been determined that immediate action is required to operate specific plant equipment in order to stop an in-progress release
- The Dose Assessment Supervisor is NOT yet available to approve the Emergency Dose Authorization
- The Emergency Dose Authorization has been approved by the Emergency Director and the Rad Protection Coordinator

What is the MAXIMUM Total Effective Dose Equivalent (TEDE) radiation exposure that the Emergency Director can direct emergency personnel to receive for these conditions?

a. 2 Rem

b. 4 Rem

c. 5 Rem

d. 10 Rem

52. Given the following conditions:

- The Unit 1 Extra PCO is writing a blocking permit for a plant component in an area with a 6.5 rem/hour dose rate requiring a Health Physics escort for entry
- The component is already in the required position and has remote indication

Which of the following describes how the component blocking is accomplished for these conditions?

The Unit Supervisor will:

a. approve red tag installation directly on the component by Operations Personnel and waive the Independent Verification requirement.

b. direct Health Physics to hold the red tag and provide it as part of the Radiation Work Permit briefing to all personnel subsequently entering the area.

c. direct the red tag be installed on the knob or handle of the door to the area where the component is located.

d. approve the permit without the need for red tag installation if the Operations Lock is accounted for on the permit.

53. Due to Simplex Fire Protection sensor failure, an hourly firewatch is required in a High Radiation Area.

Which of the following describes the restrictions on these firewatch tours?

The Firewatch individual:

a. shall step into the area, make an observation and exit the area.

b. must be escorted by a Health Physics Technician.

c. shall perform a normal walkthrough inspection of the area if total dose expected to be received is less than 10 mrem.

d. may only be a Health Physics Technician.

An emergency on Unit 1 has occurred requiring immediate actions be taken that depart from the requirements of Technical Specifications. No actions consistent with Technical Specifications that can provide adequate equivalent protection are immediately apparent.

Which of the following identifies who is required to approve these actions and the specific conditions allowing the actions to be taken as directed in 10CFR50.54(x) & (y)?

a. The Emergency Director (Unit 1 Shift Supervisor) approves actions to be taken to protect the health and safety of the personnel outside the SSES site boundary.

b. The Emergency Director (General Manager - SSES) approves actions to be taken to protect the health and safety of the personnel outside the SSES site boundary.

c. The Emergency Director (Unit 1 Shift Supervisor) approves actions to be taken to protect the health and safety of the personnel inside the SSES site boundary.

d. The Emergency Director (General Manager - SSES) approves actions to be taken to protect the health and safety of the personnel inside the SSES site boundary.

55. What is LATEST time that the Emergency Director shall ensure that the State and Local agencies are notified of an emergency once the conditions for an Emergency Action Level (EAL) have been identified? Assume the EAL conditions were identified at 0815.

a. 0830

b. 0845

c. 0915

d. 0945

Given the following conditions:

- During a transient Unit 2 momentarily met the conditions requiring a Site Area Emergency
- Prior to the actual classification being made, conditions continued to change such that an Alert is now the appropriate classification

What is the guidance for the classification of this event?

The event shall be classified as:

a. a Site Area Emergency and then downgraded to an Alert after the initial Emergency Notification Report has been acknowledged by the NRC, state and local agencies.

b. an Alert, but should make note of the momentarily Site Area Emergency conditions on the Emergency Notification Report.

c. a Site Area Emergency, make the appropriate notifications and then downgrade the classification to an Alert as soon as possible with management concurrence.

d. an Alert, but should consider upgrading to the Site Area Emergency once all emergency response facilities are activated.

57. Given the following conditions:

- Unit 1 is operating at 100% power
- An Electro-Hydraulic Control (EHC) malfunction has resulted in rapidly rising reactor pressure
- Reactor pressure has reached 1100 psig

What are the EXPECTED Unit PCO actions for these conditions?

a. Initiate a manual reactor scram and inform the Unit Supervisor of the condition and the action taken.

b. Immediately lower the setpoint of the Maximum Combined Flow Limiter to reduce reactor pressure.

c. Inform the Unit Supervisor of the condition and initiate a manual reactor scram when directed.

d. Immediately reduce reactor pressure by placing the Turbine Bypass Valves in "Test" and opening them.

With Unit 1 performing a startup from Cold Shutdown when do the operator actions required by Technical Specifications first become applicable should a Recirculation Pump trip occur?

a. The Reactor Mode Switch has been placed in "Run".

b. The reactor is at or above criticality.

c. The Reactor Mode Switch has been placed in "Startup/Hot Standby".

d. Reactor coolant temperature is > 200 degrees F.

59. Given the following conditions:

- Unit 1 had been operating at 90% power
- The "A" Recirculation Pump tripped
- Parameter verification shows the plant operating in Region II of the Power/Flow Map

Select the desired method for exiting this region.

a. Raise flow by raising the speed of the "B" Recirculation Pump

b. Place the Reactor Mode Switch in "Shutdown" and enter ON-100-101, "Scram"

c. Raise flow by restarting the "A" Recirculation Pump.

d. Reduce power by reducing recirculation flow.

60. Given the following conditions:

- Unit 2 is operating at 22% power with power ascension in progress
- All plant systems are operating as designed
- Main condenser backpressure is 6.0" HgA and is rising
- No operator actions are taken

The reactor will scram due to:

a. a main turbine trip.

b. main steam isolation valve closure.

c. high reactor pressure.

d. low reactor water level.

. Given the following conditions:

- A Station Blackout (SBO) has occurred
- Unit 1 Reactor water level control is via Reactor Core Isolation Cooling (RCIC)
- The Condensate Storage Tank is NOT available due to a tank rupture

Which of the following describes how RCIC operation for level control is accomplished with steadily rising suppression pool temperatures (and subsequent rising lube oil temperatures) during the SBO?

a. RCIC suction is lined up to the Refueling Water Storage Tank (RWST) for a source of cool water.

b. RCIC lube oil cooling water is supplied from the Fire Protection System.

c. All RCIC protective features and trips are bypassed by EO-100-033, "RCIC Operating Guidelines During Station Blackout".

d. RCIC will be run only as necessary to maintain reactor water level +13 to +54".

62. Given the following conditions:

- Unit 2 is performing a startup with the Reactor Mode Switch in "Startup/ Hot Standby"
- Main condenser vacuum has been established
- The Outboard Main Steam Isolation Valves have just been opened and steam line warming is in progress
- The "B" Reactor Protection System MG set has just tripped
- The alternate power supply is not available

How will this bus loss affect the plant assuming it is NOT restored as directed by ON-158-001, "Loss Of RPS"?

a. Main condenser vacuum will begin to degrade.

b. The Recirculation Pumps will immediately trip.

c. The Scram Discharge Volume will begin filling.

d. The Outboard Main Steam Isolation Valves will begin to drift closed.

. The "D" Diesel Generator is running with its Unit 1 output breaker (1A204-04) closed following a valid start signal. 125 VDC Bus 1D644 is then deenergized.

The "D" Diesel Generator:

a. output breaker will trip and the engine may trip on overspeed.

b. will trip and the output breaker will have to be opened locally.

c. will continue running as before but all automatic protective features are Inoperable.

d. should be placed in Local Control Mode and the DC power selector transferred to the Unit 2 power supply.

64. Given the following conditions:

- Unit 1 was operating at 100% when a generator fault resulted in a main turbine trip
- The Extra PCO verified the generator and turbine trip but reports that turbine speed is 1920 rpm and is rising

Which of the following should be directed by the Unit Supervisor?

a. Place the running and standby EHC Pumps in "Stop".

b. Open the Moisture Separator Main Steam Cross-Around line drain valves.

c. Break main condenser vacuum.

d. Close the Main Steam Isolation Valves.

65. While operating in accordance with ON-100-101, "Scram", on a normal plant shutdown reactor scram, which of the following criteria is utilized to determine if EO-100-113, "Level/Power Control" entry is also required?

a. The position and number of control rods inserted.

b. The value of reactor Source Range Monitor (SRM) period after rod movement and detector insertion is complete.

c. The status of the Average Power Range Monitor (ARPM) "Downscale" lights.

d. The ability to monitor instrumentation for valid, current reactor power level.

Given the following conditions:

- Unit 1 has been scrammed
- A large coolant leak into the drywell is occurring
- In anticipation of rapid depressurization, all Bypass Valves have been opened
- Reactor pressure has been reduced to 175 psig
- Conditions worsen requiring entry into EO-100-112, "Rapid Depressurization"

Select the required actions for these conditions.

a. Open the 6 ADS valves and close the Bypass Valves.

b. Close the Bypass Valves and open the 6 ADS valves

c. Open the 6 ADS valves and leave the Bypass Valves open.

d. Complete the depressurization using only the Bypass Valves.

67. Given the following conditions:

- Unit 1 is operating at 100% power
- A loss of coolant accident occurs
- Reactor water level is -50 inches
- Drywell pressure is 2.4 psig
- All plant systems respond as designed

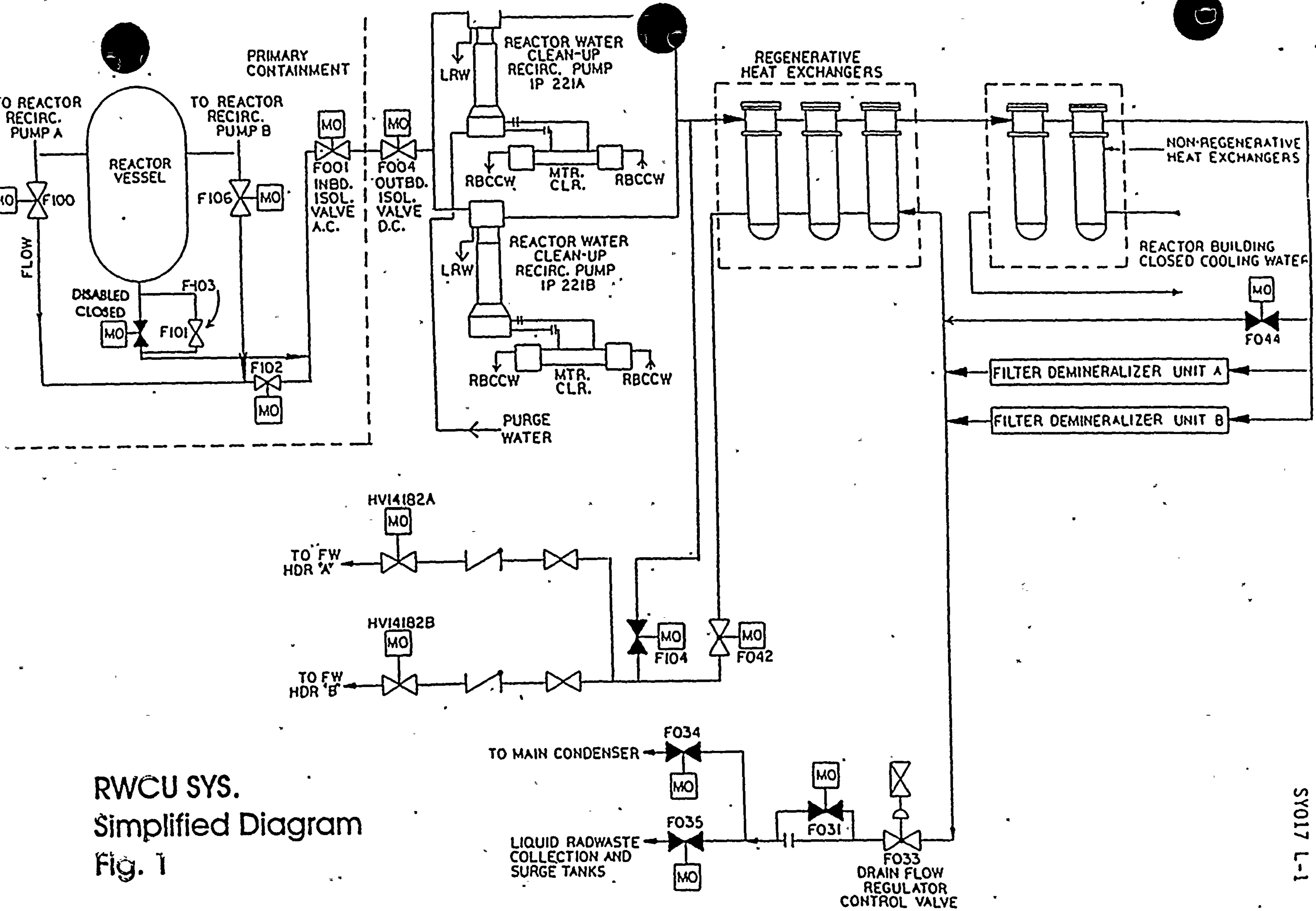
Using the attached Reactor Water Cleanup System diagram, determine the valves that REQUIRE operator action to be closed for completion of the system isolation for these plant conditions.

a. HV-144-F001 and HV-144-F004

b. HV-144-F042 and HV-144-F104

c. HV-14182A and HV-14182B

d. HV-144-F100 and HV-144-F106



RWCU SYS.
Simplified Diagram
Fig. 1

SY017 L-1

Given the following conditions:

- Unit 1 has performed a manual reactor scram as directed by ON-100-101, "Scram"
- The reason for scramming was a trip of both Recirculation Pumps
- The Control Rod Drive Flow Controller has been lowered to "Minimum" as directed by the ON
- The delta T between the reactor bottom head drain and the steam dome is 156 degrees F

For these conditions the operator is required to:

a. establish natural circulation flow.

b. cooldown to Mode 4.

c. start at least one Recirc Pump.

d. ensure natural circulation flow will not occur.

69. A small Recirculation loop leak exists on Unit 2.

Which of the following describes the expected pressure relationship between the drywell and suppression chamber as the leak continues and pressure rises?

Drywell pressure:

a. will rise to about 4.5 to 5.0 psi above suppression chamber, the two pressures will equalize and remain nearly equal as the leak continues.

b. will rise to about 0.5 to 1.0 psi above suppression chamber and that differential will be maintained as the leak continues.

c. and suppression chamber pressure will initially equalize and maintain that equalization as the leak continues.

d. will rise to about 4.5 to 5.0 psi above suppression chamber and that differential will be maintained as the leak continues.

Given the following conditions:

- A large leak into the drywell has occurred on Unit 1
- Drywell pressure is 28 psig
- Drywell sprays are being started as directed by EO-100-103, "Primary Containment Control"
- When the Inboard Drywell Spray Isolation Valve (F016) is throttled open to establish the required spray flow, the valve strokes to the full open position instead of stopping when the handswitch is released
- No additional operator actions are taken

What is the result of this failure?

a. The Residual Heat Removal Pump goes to "runout" and trips on overcurrent.

b. Possible drywell spray header damage may occur from water hammer.

c. The limits of the RHR & CS Vortex Limit curve may be exceeded damaging the pump.

d. Possible drywell damage may occur from exceeding the differential pressure limit.

71. Given the following conditions:

- Unit 1 is operating at 100% power
- Drywell temperature and pressure are rising due to a leak
- All expected automatic actions occurred as drywell pressure exceeded 1.72 psig
- EO-100-103, "Primary Containment Control", was entered for high drywell temperature
- The sections of ES-134-001, "Restoring Drywell Cooling With A LOCA Signal Present", appropriate for current plant conditions, have been completed

Which of the following describes the current drywell cooling capabilities for these conditions?

The Drywell Cooling Fans are:

a. running with Reactor Building Chilled Water supplying the coolers.

b. running with no cooling water to the coolers.

c. running with Reactor Building Closed Cooling Water supplying the coolers.

d. tripped due to the current LOCA conditions and will not be restarted until drywell spraying has been completed.

72. Given the following conditions AFTER a transient from 90% power on Unit 1:

- Reactor power (MWt) is slightly higher
- Generator megawatts (MWe) are slightly lower
- Indicated feedwater flow is greater than indicated steam flow (matched before the transient)
- Reactor water level is slightly lower

These conditions are being caused by:

a. isolation of extraction steam to one feedwater heater.

b. a stuck open Safety Relief Valve.

c. rising main condenser backpressure (degrading vacuum).

d. failure of the on-service EHC pressure regulator to a lower output.

73. Given the following conditions:

- Unit 1 has experienced a Main Steam Isolation Valve closure from 100% power
- The control rods did not insert
- EO-100-113, "Level/Power Control", has been entered
- The Safety Relief Valves have been manually opened to control pressure less than 965 psig
- Standby Liquid Control is not available

For these conditions, the Heat Capacity Temperature Limit:

a. will steadily become more restrictive.

b. will remain constant.

c. will steadily become less restrictive.

d. has been exceeded.

While at 90% power, Unit 1 has experienced a loss of feedwater heating resulting in a feedwater temperature drop of 55 degrees F.

Assuming no operator actions taken, what is the operational concern for these conditions?

a. Immediate core flux oscillations

b. Recirculation loop jet pump vibrations.

c. Violation of the Susquehanna Unit 1 Operating License

d. Entry into Region I of the Power/Flow Map

75. Given the following conditions:

- Unit 1 is operating at 100% power
- A complete loss of the Rod Position Indication System has occurred requiring a shutdown
- Recirculation flow has been reduced to 55 mlbm/hour and the Reactor Mode Switch placed in "Shutdown"

For these conditions, how will the Unit Supervisor (US) make the determination on whether injection of Standby Liquid Control is required?

a. Control rod position can be verified by demanding an OD-7, Option 1 printout.

b. The Unit PCO can monitor Average Power Range Monitor (APRM) power levels.

c. Control Rod position can be verified by the Rod Worth Minimizer Full Core Display screen.

d. The Unit PCO can verify a red "Scram Valves" light is received for each control rod.

76. A Control Room evacuation is required. All Immediate Operator Actions of ON-100-009, "Control Room Evacuation", were completed prior to leaving.

What will be the current means of core heat removal when the operators arrive to establish control at the Remote Shutdown Panel?

a. Recirculation flow removing core heat for dissipation via the Safety Relief Valves.

b. Natural circulation flow removing core heat for dissipation via Turbine Bypass Valves.

c. Recirculation flow removing core heat for dissipation via the Turbine Bypass Valves.

d. Natural circulation flow removing core heat for dissipation via the Safety Relief Valves.

Given the following conditions:

- A Unit 1 fire has resulted in the closure of all Outboard Main Steam Isolation Valves from 100% power
- High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) both automatically initiated and are injecting
- The Immediate Operator Actions of ON-100-009, "Control Room Evacuation" were completed
- All Remote Shutdown Panel (RSP) Control Transfer Switches have been placed in "Emergency"
- The RSP operator trips RCIC when reactor water level reaches +54 inches

Reactor water level will:

a. lower until RCIC automatically re-initiates at -30 inches.

b. lower until HPCI automatically re-initiates at -38 inches.

c. lower until both HPCI and RCIC automatically re-initiate.

d. continue to rise due to HPCI injection.

Entry into EO-100-105, "Radioactivity Release Control", and completion of the required actions will limit the activity release from:

a. the reactor coolant into the primary containment.

b. the reactor coolant into areas outside the primary and secondary containment.

c. damaged fuel directly into the reactor coolant and plant primary systems.

d. the reactor coolant into the secondary containment.

Given the following conditions:

- Unit 2 is operating at 100% power
- The "A" Reactor Protection System (RPS) Bus is on the alternate power supply
- The "B" RPS MG Set has just tripped

Which of the following describes the restrictions on continued plant operation for these conditions?

The plant may operate in Mode 1 for a limited amount of time based upon:

a. the availability of the Reactor Building Equipment Drain Sump Pumps.

b. the rate at which the instrument air supply to the Outboard MSIVs depressurizes.

c. the availability of the Reactor Recirculation Pumps.

d. the rate at which the Scram Discharge Volume fills.

80. Given the following conditions:

- Unit 1 is operating at 35% power
- Unit 2 Instrument Air is NOT available
- Unit 1 Instrument Air pressure is 105 psig and is slowly lowering

When is Unit 1 REQUIRED to be scrammed?

a. More than 2 control rod "drift" alarms are received.

b. Instrument Air pressure has reached 95 psig.

c. The Scram Discharge Volume high level control rod block is received.

d. The red "Scram Valves" light is received for any control rod.

81. With Unit 1 at 75% power, the Inboard Main Steam Isolation Valve (MSIV) in the "A" Main Steam Line fails closed.

Select the expected automatic plant response.

a. A half scram on "A" RPS occurs.

b. The remaining 7 MSIVs close.

c. The reactor will stabilize at a lower pressure.

d. The reactor power will stabilize at a higher power.

Given the following conditions:

- Unit 2 has experienced a loss of Shutdown Cooling while in Mode 3
- Primary and Secondary Containment are established
- The plant has been shutdown for 36 hours
- Reactor water level is stable at +48 inches
- Reactor pressure is being maintained 20 to 98 psig by opening Non-ADS Safety Relief Valves (SRV) as needed
- Following opening of the "B" SRV, the Extra PCO is unable to close the valve

Which of the following describes the effect of this failure to close as the reactor depressurizes?

a. SRV "Open" position indication from the Acoustic Monitor will be lost as discharge downcomer flow lowers.

b. The reactor will reach saturation temperature with a subsequent reduction in the "time-to-boiling" value.

c. Adequate core cooling will not be maintained for these conditions.

d. The SRV discharge downcomer may begin to reflood with suppression pool water.

Given the following conditions:

- Unit 1 is performing a reactor startup
- Reactor pressure is 825 psig
- The Reactor Mode Switch is in "Startup/Hot Standby"
- Control Rods 30-15 and 46-47 (both at Notch "00") have accumulator alarms in on low pressure and are being recharged
- The "A" Control Rod Drive Pump is not available
- The "B" Control Rod Drive Pump has just tripped and cannot be restarted
- Charging header pressure has equalized with reactor pressure

Which of the following describes the plant conditions requiring the Reactor Mode Switch be placed in "Shutdown"?

a. Charging header pressure cannot be raised to or above 940 psig within 20 minutes.

b. An accumulator alarm is received on control rod 46-43 at Notch "00".

c. An accumulator alarm is received on a currently withdrawn control rod.

d. Control rods 30-15 and 46-47 cannot be returned to Operable status within 20 minutes.

Given the following conditions:

- Unit 1 is in Mode 5
- The "A" Residual Heat Removal (RHR) loop is being placed in the Fuel Pool Cooling mode

Which of the following prevents draining the containment fuel pools to the suppression pool via the RHR Minimum Flow Valve (F007A) when starting the "A" RHR Pump?

a. The operator is procedurally directed to establish flow to the fuel pools before the F007A valve automatically opens.

b. F007A is manually overridden closed by the operator prior to starting the RHR pump.

c. The RHR pump is started with a complete, established flowpath to the fuel pools to prevent this.

d. The F007A automatic operation is defeated by lifting leads during the Fuel Pool Cooling mode lineup.

85. Given the following parameters:

- Drywell pressure	3.5 psig and rising
- Drywell temperature	145 degrees F and rising
- Suppression chamber pressure	4.6 psig and rising
- Suppression pool water temperature	87 degrees F and steady

Which of the following describes what has occurred?

a. A downcomer vacuum breaker has failed open during a recirculation leak to the drywell.

b. A pipe break into the drywell has occurred with a suppression chamber to drywell vacuum breaker open.

c. A safety relief valve tail pipe has broken above the suppression pool water level while the valve is open.

d. A recirculation line partial break has occurred with all containment parameters responding as designed.

. Given the following conditions:

- Unit 1 was operating at 100% power
- A severe overpressure transient has resulted in the Safety Relief Valves (SRV) opening in their "Safety Valve" mode
- All valves, with the exception of one, have reseated (closed)
- The required actions of ON-183-001, "Stuck Open Safety Relief Valve" have been completed
- The reactor has been scrammed
- The SRV has NOT closed

#86 deleted. No correct ans.

As the reactor cools down and depressurizes through the stuck open SRV tail pipe temperature will:

a. start at 305 degrees F and will slowly fall following reactor pressure during the depressurization.

b. start at 270 degrees F, rise to approximately 300 degrees F and then will slowly fall following reactor pressure during the depressurization below 500 psig

c. start at 525 degrees F and will slowly fall following reactor pressure during the depressurization.

d. start at 285 degrees F, rise to approximately 325 degrees F and then will slowly fall following reactor pressure during the depressurization below 500 psig

87. The Unit 1 Reactor Mode Switch was placed in "Shutdown" due to suppression pool temperature being greater than the Technical Specification limit.

Suppression pool temperature must be at or below:

a. 110 degrees F for 36 hours prior to entering Mode 3.

b. 90 degrees F within 24 hours of placing the Reactor Mode Switch in "Shutdown".

c. 110 degrees F prior to entering Mode 2 on the ensuing startup.

d. 90 degrees F prior to reaching the point of adding heat on the ensuing startup.

38. Given the following conditions:

- Unit 1 is operating at 50% power
- Suppression pool cooling is in service
- High Pressure Coolant Injection (HPCI) is operating in the CST to CST mode for a surveillance
- During the surveillance suppression pool temperature reached 96 degrees F

What are the requirements for entry into, and implementation of, EO-100-103, "Primary Containment Control", for these conditions?

a. Technical Specifications modify the Emergency Operating Procedure entry condition to 105 degrees F while surveillance testing to the suppression pool is in progress.

b. EO-100-103 actions may be deferred for 24 hours while suppression pool temperature is reduced to less than 90 degrees F.

c. The HPCI surveillance procedures allow 4 hours to reduce suppression pool temperature below 90 degrees F before EO-100-103 entry is required.

d. The actions of EO-100-103 are required to be performed as soon as suppression pool temperature is above 90 degrees F.

39. Given the following conditions:

- Unit 2 is operating at 100% power
- Drywell pressure and temperatures are rising rapidly
- High Pressure Coolant Injection (HPCI) did not start on high drywell pressure

As these conditions worsen and water level lowers following the scram, HPCI:

a. must be initiated by the operator because wide range level indication will be off-scale low.

b. will initiate late because the wide range level indication will be reading higher than actual water level.

c. will not initiate because wide range level indication will be off-scale high.

d. will initiate early because the wide range level indication will be reading lower than actual water level.

Which of the following describes how the operator determines if water level in the containment is above the top of active fuel while flooding the primary containment?

Top of active fuel is determined by:

a. indicated drywell pressure versus containment level correlation if the drywell is vented to atmosphere.

b. a pressure and temperature corrected reading from Wide.Range Suppression Pool Level indication.

c. a level calculated from the pressure differential between the drywell and the suppression chamber.

d. direct reading from the reactor water level Fuel Zone Level indicator if the drywell is vented to atmosphere.

91. Given the following conditions on Unit 1:

- A failure-to-scram (ATWS) condition exists
- Reactor power is 22%
- Standby Liquid Control is injecting
- The Scram Discharge Volume did NOT isolate
- Suppression pool level is 15 feet and lowering
- A greater than Max Safe Water Level exists in two (2) Reactor Building areas

Which of the following are the appropriate actions for these conditions?

a. Immediately open 6 ADS Safety Relief Valves.

b. Take no action until power is less than 5% or all rods are inserted.

c. Immediately open the Turbine Bypass Valves.

d. Take no action until suppression pool reaches 12 feet.

Given the following conditions:

- Reactor Core Isolation Cooling (RCIC) is providing injection to the reactor
- Reactor pressure is 455 psig and lowering
- Suppression pool water level is 16 feet and lowering
- Suppression pool temperature is 155 degrees F and rising
- The plant is operating in accordance with EO-100-103, "Primary Containment Control"

Which of the following is the expected result with RCIC continuing to run under these conditions?

a. The Heat Capacity Temperature Limit will be exceeded.

b. RCIC will trip.

c. Suppression chamber design pressure will be exceeded.

d. RCIC will cavitate.

93. Conditions on Unit 1 are such that EO-100-102, "RPV Control", requires steam cooling.

If the coolant inventory remaining in the reactor vessel is the source of steam for steam cooling, which of the following describes why water level must reach -205 inches before initiating steam cooling?

a. The reduced level ensures the uncovered fuel will be hot enough to provide a large differential temperature between it and the steam being generated allowing maximum heat removal.

b. Core temperatures will lower, allowing additional time for restoration of an injection source before the rapid depressurization is required.

c. Allowing level to lower will reduce the reactor core differential pressure assisting the thermal driving head for natural circulation flow.

d. This level ensures the initial swell upon depressurization will sweep enough coolant past the fuel to break up the boundary layer maximizing heat transfer.

While operating in EO-100-104/EO-200-104, "Secondary Containment Control", the Max Safe Temperatures for the HPCI Equipment Areas are different between Unit 1 (300 degrees F) and Unit 2 (240 degrees F).

Which of the following describes the reason for this difference and how that difference will affect operation in Secondary Containment Control?

a. The Unit 2 HPCI Room room coolers are arranged differently and can be provided with cooling from both DX Units. This additional cooling capacity allows lower EO-200-104 temperature limits.

b. The Unit 2 safe shutdown analysis for HPCI equipment operability concerns during loss of off-site power was more restrictive than that done on Unit 1. Thus, EO-200-104 requires action earlier than EO-100-104.

c. On Unit 2, temperature instrumentation location for RCIC and HPCI is such that the rooms are considered one "area" for EO-200-104 purposes. Therefore, the more restrictive RCIC Max Safe Temperature is limiting.

d. Post loss of off-site power natural ventilation flow has more heat removal capabilities in the Unit 2 Reactor Building as opposed to Unit 1. Additional equipment operability analysis allows a higher temperature in EO-100-104.

With Unit 1 at power an EO-100-104, "Secondary Containment Control", entry condition has been received.

Which of the following EO-100-104 directed actions will NOT reduce any current and future Off-Site doses for these conditions?

a. "Go to RPV Control" - Step SC/R-5

b. "Rapid Depress is required" - Step SC/R-6

c. "Restart RB HVAC" - Step SC-3

d. "Isolate all systems discharging into area" - Step SC/R-1

Given the following conditions:

- A confirmed fuel failure has occurred on Unit 1 resulting in a Main Steam Isolation Valve closure
- The HPCI Equipment Area high water level alarm was received just after the Safety Relief Valves opened on the scram
- Suppression pool water level is lowering
- The Reactor Building general area radiation levels are 7.5 rem/hour

Which of the following describes how the water level in the HPCI Equipment Area should be determined in order to take the actions as required in EO-100-104, "Secondary Containment Control"?

a. Assume the water level in the HPCI Equipment Area is above Max Safe Water Level.

b. Calculate the suppression pool water level loss rate and assume it is all going to the HPCI Equipment Area.

c. Obtain a dose extension authorization and attempt a direct observation of HPCI Equipment Area water level.

d. Calculate the Reactor Building Floor Drain Sump Pump run times and extrapolate that value to a HPCI Equipment Area water level.

97. Given the following conditions:

- Unit 1 had a main turbine trip from 95% power
- 125 control rods did NOT insert on the scram
- High Pressure Coolant Injection is not available
- The Unit Supervisor determined that reactor water level could not be maintained > -161" and directed a Rapid Depressurization
- All injection to the reactor (except CRD, SLC and RCIC) has been stopped and prevented

The Unit Supervisor shall direct restarting injection flow to the reactor when:

a. reactor power is less than 5%.

b. reactor water level is -205 inches.

c. reactor pressure is less than 152 psig.

d. 6 ADS Safety Relief Valves have been confirmed open.

98. While operating in accordance with EO-100-113, "Level/Power Control", the operator is directed to lower level to between -60 and -110 inches (Step LQ/L-6) utilizing Table 15 systems.

Which of the following describes why the Low Pressure Coolant Injection (LPCI) mode of Residual Heat Removal (RHR) system is the LEAST preferred Table 15 system for accomplishing this step?

a. Utilizing the other Table 15 systems first maintains RHR available for containment and/or suppression pool problems during the ATWS.

b. The LPCI injection flowpath receives minimal preheating and its use may result in power/flow instabilities as level is lowered.

c. The relatively low RHR Pump shutoff head limits the systems' ability to inject during an high power/pressure ATWS.

d. The high RHR Pump flow rates may result in sweeping any injected boron out of the core resulting in a power rise as level is lowered.

99. EO-100-105, "Radioactivity Release Control", directs isolation of all primary systems discharging into areas outside Primary Containment or Reactor Building except those systems required to support EOP/DSP actions.

These systems are specifically exempted from isolation because:

a. additional off-site releases from them are unlikely.

b. they are required to support alternate reactor depressurization methods.

c. their isolation may result in larger, uncontrolled releases as the transient continues.

d. these additional isolations would require an unnecessarily escalation of the emergency classification.

100. Unit 1 is operating in accordance with ON-113-001, "Response To Fire".

Select the specific conditions that direct the Unit Supervisor to EXIT ON-113-001 even with a fire still burning.

a. The fire is affecting Unit equipment required to reach and maintain "safe shutdown".

b. The Fire Brigade Leader has determined that off-site fire fighting assistance is required.

c. Any Emergency Operating Procedure entry condition is met.

d. ON-100-009, "Control Room Evacuation", entry is required.

Senior Reactor Operator Answer Key

1. b
2. b
3. c
4. c
5. c
6. b
7. ~~d~~ b LEB
8. a
9. a
10. c
11. a
12. c
13. a
14. b
15. c
16. b
17. a
18. b
19. d
20. a
21. d
22. d
23. a
24. d
25. c
26. b
27. b
28. c
29. a
30. b
31. a
32. b
33. d
34. a
35. b
36. c
37. a
38. b
39. c
40. a
41. d
42. c
43. b
44. d
45. c
46. c
47. b
48. a
49. d
50. d

Change based on a review of licensee's comments following the exam.

Larry E. Briggs
Chief Examiner

Senior Reactor Operator Answer Key

51. b
52. c
53. a OR b. JEB
54. a
55. b OR a. JEB
56. c
57. a
58. c
59. a
60. d
61. b
62. a
63. ~~c~~ b. JEB
64. d
65. a
66. c
67. c
68. d
69. d
70. d
71. b
72. b
73. a
74. c
75. b

76. d OR a. JEB
77. b
78. b
79. c
80. a
81. d
82. d
83. c
84. d
85. c
~~86. d~~ deleted JEB
87. d OR C JEB
88. d
89. b
90. a
91. a
92. b
93. a
94. c
95. c
96. a
97. d
98. b
99. c
00. d

50-387/388
1/24/2000
99-12

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Subject:
NRC Integrated Inspection Reports 50--387/99-12 and 50--388/99-12 at Susquehanna Steam Electric Station on November 20, 1999 through January 1, 2000.

Body:

Docket: 05000387, Notes: N/A

Docket: 05000388, Notes: N/A

January 24, 2000

Mr. Robert G. Byram
Senior Vice President, Nuclear
PP&L, Inc.
2 North Ninth Street
Allentown, PA 18101

SUBJECT: **NRC INTEGRATED INSPECTION REPORT 05000387/1999012 and 05000388/1999012**

Dear Mr. Byram:

On January 1, 2000, the NRC completed an inspection at the Susquehanna Steam Electric Station (SSES) Unit 1& 2 reactor facilities. The enclosed report covered routine activities by the resident inspectors and announced inspections of your Security and Safeguards, and Radiological Controls-External and Internal Exposure programs by Region I specialists. The inspectors discussed the findings of these inspections with Mr. R. Saunders, Vice President Nuclear Operations, Mr. B. Shriver, General Manager SSES, and other members of your staff, at an exit meeting at the completion of the inspections.

Overall, your staff safely operated the facility during this period. Plant Management's decisions to perform a controlled shutdown of Unit 2 to address the increase in primary containment unidentified water leakage and to correct additional known equipment problems prior to restart was a positive initiative.

In accordance with 10CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure(s), and your response will be placed in the NRC Public Document Room (PDR).

A reply to this letter is not required, but should you have any questions regarding this please contact me at 610-337-5322.

Sincerely,

ORIGINAL SIGNED BY

Curtis J. Cowgill, Chief
Projects Branch 4
Division of Reactor Projects

Docket Nos: 05000387, 05000388
License Nos: NPF-14, NPF-22

Enclosure: Inspection Report 05000387/1999012, 05000388/1999012

IE:01

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RGN-002

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U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket Nos:	05000387, 05000388
License Nos:	NPF-14, NPF-22
Report No.	05000387/1999012, 05000388/1999012
Licensee:	PP&L, Inc. 2 North Ninth Street Allentown, PA 19101
Facility:	Susquehanna Steam Electric Station
Location:	P.O. Box 35 Berwick, PA 18603-0035
Dates:	November 20, 1999 through January 1, 2000
Inspectors:	S. Hansell, Senior Resident Inspector J. Richmond, Resident Inspector A. Blamey, Resident Inspector P. Frechette, Security Specialist J. McFadden, Radiation Specialist
Approved by:	Curtis J. Cowgill, Chief Projects Branch 4 Division of Reactor Projects

EXECUTIVE SUMMARY

Susquehanna Steam Electric Station (SSES), Units 1 & 2
NRC Inspection Report 05000387/1999012, 05000388/1999012

This inspection included aspects of PP&L's operations, maintenance, engineering and plant support at SSES. The report covers a five-week period of routine resident inspection activities and announced inspections by regional specialists.

Operations

- PP&L made conservative and effective decisions in response to increasing primary containment leakage on Unit 2. (Section O4.1)

- Two recent equipment failures related to the Unit 2 main transformer and Unit 1 reactor core isolation cooling temperature switch module were attributed to inadequate follow-up actions related to industry event information that had been previously reviewed by PP&L in the 1986 and 1990 time frames. (Section O8.1)

Maintenance

- After PP&L management established an Event Review Team, PP&L successfully resolved the numerous problems that occurred following the 2 year preventive maintenance on the "A" emergency diesel generator. (Section M1.2)

- During the planned replacement of two emergency service water (ESW) pumps, PP&L's maintenance department exhibited excellent work performance and good management oversight. (Section M1.3)

Engineering

- The Independent Safety Engineering Group report results were indicative of thorough investigation and analysis of plant issues and personnel performance. The reports were objective and contained meaningful feedback to plant management. (Section E7.1)

Plant Support

- PP&L implemented effective applied radiological controls. The radiation work permit program was adequately implemented. Personnel occupational exposure was maintained within applicable regulatory limits and as low as reasonably achievable. Access controls to radiologically controlled areas were effective, and appropriate occupational exposure monitoring devices were provided and used. (Section R1.1)

- PP&L implemented overall effective surveys, monitoring, and control of radioactive materials and contamination. Health Physics technicians properly documented survey results. In general, radiological housekeeping conditions were acceptable. (Section R1.2)

- Security and safeguards activities with respect to alarm station controls, communications, and protected area access control of personnel, packages and vehicles were effectively implemented. (Section S1)

- Security and safeguards procedures and documentation were properly implemented. Event logs were properly maintained and effectively used to analyze, track, and resolve safeguards events. (Section S3)

- The security force members (SFMs) were provided effective training and adequately demonstrated that they had the requisite knowledge necessary to effectively implement their duties and responsibilities. (Sections S4 and S5)

- Management support was adequate to ensure effective implementation of the security program, as evidenced by adequate staffing levels and the allocations of resources to support programmatic needs. (Section S6)

TABLE OF CONTENTS

Report Details

Summary of Plant Status

Susquehanna Steam Electric Station (SSES) Unit 1 operated at 100% power throughout the inspection period with two exceptions. On December 4, power was reduced to 75% to change control rod positions and to perform control rod insertion time and main steam isolation valve testing, then returned to 100% power. On December 31, power was reduced to 80% as a year 2000 contingency, then returned to 100% on January 1, 2000.

SSES Unit 2 operated at 100% power throughout the inspection period with three exceptions. On December 11, power was reduced to 85% to change control rod positions and perform control rod insertion time testing, then returned to 100% power. On December 17, a normal shutdown was performed to repair a leaking instrument line for the "A" reactor recirculation pump. The Unit was restarted on December 23, and reached 100% power on December 25. On December 31, power was reduced to 80% as a year 2000 contingency, then returned to 100% on January 1, 2000.

I. Operations

O1 Conduct of Operations [1]

O1.1 Unit Operations and Operator Activities (71707)

The inspectors determined routine operator activities were satisfactorily established, communicated and conservatively performed in accordance with SSES procedures. Control room logs accurately reflected plant activities. During tours of the main control room, the inspectors observed good turn-over briefings and formal communications.

O2 Operational Status of Facilities and Equipment

O2.1 Operational Safety System Alignment (71707)

During routine plant tours, the proper alignment and operability of various safety systems, engineered safety features, and on-site power sources were verified. Partial walkdowns were performed for the emergency service water, "A" emergency diesel generator, control rod drive, and reactor recirculation systems. No equipment problems were noted.

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1 Topical headings such as O1, M8, etc., are used in accordance with the NRC standardized reactor inspection report outline. Individual reports are not expected to address all outline topics.

O4 Operator Knowledge and Performance

O4.1 Unit 2 Reactor Shutdown and Plant Restart

a. Inspection Scope (71707,40500)

The inspectors reviewed PP&L's response to an increase in primary containment unidentified water leakage; the management evaluation and decision to perform a controlled reactor shutdown; and the assessment of the operator actions during the plant shutdown, equipment repairs, and subsequent reactor startup.

b. Observations and Findings

In response to an increasing primary containment unidentified water leakage, operators started reducing reactor power on Unit 2 on December 16, to allow for inspection inside the primary containment . Primary containment unidentified water leakage had increased to 0.87 gallons per minute (gpm.) The Technical Specification (TS) limit was 5 gpm.

The PP&L inspection discovered a small water leak on a 3/4 inch instrument pipe associated with the pressure indication for the "A" reactor recirculation pump seal. The leak was located at a welded 45 degree elbow connection. PP&L determined that the weld cracked due to high cycle fatigue caused by vibrational stresses. The line was replaced with a modified pipe that eliminated the 45 degree elbow weld. In addition, a pipe hanger was added to provide added support. PP&L inspected the "B" pump pipe and other similar reactor recirculation pipes and found no additional problems.

The "A" reactor recirculation pump pipe repairs were completed December 20, 1999. PP&L management decided to keep the unit shutdown to repair several other equipment reliability problems prior to plant restart. The decision to correct additional known equipment problems prior to restart was in line with PP&L's new policy concerning improvement in equipment reliability. Unit 2 was restarted safely on December 23, and reached full power on December 25.

c. Conclusions

PP&L made conservative and effective decisions in response to increasing primary containment leakage on Unit 2.

O8 Miscellaneous Operations Issues

O8.1 Licensee Event Report (LER) Review (71707,92700)

(Closed) LER 50-387/99-004-00
Reactor Core Isolation Cooling (RCIC) Manually Isolated due to Failure of Steam Leak Detector Temperature Switch

- On August 8, 1999, operators manually isolated RCIC in response to a steam leak detection piping area high temperature alarm. The alarm was caused by a failure of a temperature switch module which had been installed 3 days earlier. The module was replaced and RCIC returned to service within 4 hours.

  PP&L analysis found that a faulty power supply capacitor caused the module to fail. These modules were the subject of a 1986 General Electric Service Information Letter which recommended that the 7 year shelf life for the module should not be extended unless the capacitors were replaced with upgraded components. The failed module, although new, had been stored in the warehouse since 1984 and had not been upgraded. PP&L concluded that the vendor notice had been properly processed in accordance with the SSES Industry Event Review Program (IERP), but inadequate action had been taken for the IERP recommendations.

  The inspectors noted that this was a second example where industry event information had been previously reviewed by PP&L without adequate follow-up action. NRC IR 50-387,388/99-06 discussed the June 1999 Unit 2 main transformer failure which resulted from a manufacturing defect identified in 1990. The inspectors determined that the PP&L documentation of this event was appropriate and met the requirements of 10 CFR 50.73. This event was reviewed in more detail in NRC IR 050000387/1999012 and 050000388/1999012. This LER is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Surveillance and Pre-Planned Maintenance Activity Review

a. Inspection Scope (61726,62707,40500)

The inspectors observed and reviewed selected portions of pre-planned maintenance and surveillance activities, to determine whether the activities were conducted in accordance with NRC requirements and SSES procedures.

b. Observations and Findings

The inspectors observed portions of the following work activities and surveillances:

Work Authorizations

PCWO 205801	Unit 2 Control Rod Drive Discharge Valve Inspection and Repair
PCWO 214659	"A" Emergency Diesel Generator Troubleshooting
PCWO 215235	Excess Flow Check Valve XV-142-F059G Rework
PCWO 218447	"2B" Recirc M-G Scope Tube Lockup Investigation
PCWO 105153	"C" ESW Pump Overhaul
PCWO 106084	"C" ESW Pump Motor Bearing Replacement
PCWO 202805	"D" Emergency Service Water Pump Rebuild

- Surveillances

CH-SY-004	Functional Test of the Post Accident Sampling Station (PASS)
OP-264-001	Unit 2 Recirculation Pump Scoop Tube Unlocking
TP-024-145	"A" Emergency Diesel Generator Post Maintenance Test
SI-264-305	Recirc M-G Mechanical Stop Verification
SO-015-002	ESW Valve Stroke Testing
SE-024-B01	"B" EDG 24-hour Surveillance Run
SO-024-A01	"A" EDG Monthly Surveillance Run

In addition, selected portions of procedures and drawings associated with the maintenance and surveillance activities were also reviewed and determined to be acceptable. In general, maintenance personnel were knowledgeable of their assigned activities.

M1.2 "A" Emergency Diesel Generator Restoration following 2-Year Inspection

a. Inspection Scope (61726,62707,40500)

The inspectors observed and reviewed selected portions of the "A" Emergency Diesel Generator (EDG) restoration and surveillance activities. The activities and work documents were reviewed to determine whether the activities were conducted in accordance with NRC requirements and SSES procedures.

b. Observations and Findings

On October 4, 1999, the "A" EDG was removed from service to perform the 2 year preventative maintenance inspection. The "E" EDG was substituted for the "A" EDG. Restoration of the "A" EDG initially commenced on November 5, following completion of the planned maintenance.

During the post maintenance testing, numerous problems were encountered including an air start failure, gasket leakage (starting air header to cylinder), governor instability, and an unexpected diesel start when switching from local to remote control. After approximately 2 weeks of troubleshooting and rework failed to restore EDG operability, PP&L formed an Event Review Team (ERT) to review the "A" EDG issues and post maintenance testing methodology.

On December 3, PP&L determined that a new Agastat relay installed during the restoration troubleshooting had a manufacturing defect in the internal wiring. The internally mis-wired relay accounted for several of the problems observed during the initial restoration attempt. The ERT troubleshooting activities were thorough and the corrective action adequately resolved identified deficiencies.

The "A" EDG was successfully tested and returned to service on December 6. PP&L is evaluating the mis-wired Agastat relay in accordance with 10 CFR 50.21, "Reporting of Defects and Noncompliance."

c. Conclusions

After PP&L management established an Event Review Team, PP&L successfully resolved the numerous problems that occurred following the 2 year preventive maintenance on the “A” emergency diesel generator.

M1.3 "C" and "D" Emergency Service Water Pump Overhauls

a. Inspection Scope (61726,62707)

The inspectors observed and reviewed selected portions of the "C" and "D" Emergency Service Water (ESW) pump overhauls to determine whether the activities were conducted in accordance with NRC requirements and SSES procedures.

b. Observations and Findings

During December 13 to 16, an ESW system maintenance outage was performed to replace the "C" and "D" ESW pumps with rebuilt pumps and replace the "C" pump motor bearings. The "D" ESW pump was returned to service on December 14. The "C" ESW pump was returned to service on December 16.

The work activities were well planned, scheduled, and coordinated. The inspectors observed excellent work performance by the maintenance department under extreme weather conditions and good supervisory and management oversight.

The inspectors and a Regional risk assessment specialist reviewed PP&L's risk assessment for the planned ESW work activities. The inspectors found that PP&L's core damage risk assessment was thorough and considered all equipment and administrative controls related to station blackout and loss of off-site power scenarios. Nevertheless, the inspectors noted that by performing maintenance on two pumps in parallel, versus one pump at a time, the potential for a Technical Specification driven plant shutdown appeared to be greater. The increased potential of a forced shutdown was offset by the shorter period of pump out of service time associated with the parallel work schedule.

c. Conclusions

During the planned replacement of two emergency service water (ESW) pumps, PP&L's maintenance department exhibited excellent work performance and good management oversight.

III. Engineering

E7 Quality Assurance in Engineering Activities

E7.1 Oversight of Station Activities

a. Inspection Scope (37551)

The inspectors reviewed three Independent Safety Engineering Group (ISEG) assessment reports related to the following topics:

- ISEG report 7-99, Investigation of the Unit 1 Reactor Recirculation Runback Event of September 4, 1999.
- ISEG report 8-99, Investigation of the Response to Emergency Service Water (ESW) Flow Anomalies of September 20, 1999.
- ISEG report 9-99, Surveillance of Plant Operations, October 1999.

b. Observations and Findings

The selected ISEG reports contained extensive reviews of selected plant issues which provided recommended actions to improve performance in administrative and technical areas. The ISEG reports were indicative of thorough investigation and analysis. The 1999 evaluations were thorough and self critical of the evaluated areas. The reports contained candid feedback to station management and were documented in the corrective action program.

c. Conclusions

The Independent Safety Engineering Group report results were indicative of thorough investigation and analysis of plant issues and personnel performance. The reports were objective and contained meaningful feedback to plant management.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Radiological Controls-External and Internal Exposure

a. Inspection Scope (83750)

The inspector evaluated the effectiveness of selected aspects of the applied radiological control program. The evaluation included a selective review of the adequacy and implementation of the following radiological control program elements and activities:

- implementation of the radiation work permit (RWP) program
- RWP No. 1999-0095 and 1999-0109 related to the reactor water clean-up (RWCU) system

- access controls to radiologically controlled areas (RCAs)
- use and adequacy of personnel occupational exposure monitoring devices
- maintenance of personnel occupational radiation exposures (external and internal) within applicable regulatory limits and as low as reasonably achievable (ALARA)
- status of the National Voluntary Laboratory Accreditation Program (NVLAP)
- periodic thermoluminescent dosimeters (TLD) quality control (QC) testing
- operation and maintenance of a whole-body-counting (WBC) program
- dose calculations for skin dose and for internal uptakes

The inspector evaluated performance in the above-selected areas via observation of work activities, tours of the radiologically controlled area (RCA), discussions with plant personnel, review of documentation, and evaluation of applicable station procedures.

b. Observations and Findings

PP&L maintained personnel occupational radiation exposures (external and internal) within regulatory limits and as low as reasonably achievable (ALARA).

PP&L implemented effective access controls to the radiologically controlled areas of the station including use of RWPs, bar code readers, and computerized log-in stations. No access control deficiencies were identified. Appropriate personnel monitoring devices for access to the RCA were supplied and properly used.

c. Conclusions

PP&L implemented effective applied radiological controls. The radiation work permit program was adequately implemented. Personnel occupational exposure was maintained within applicable regulatory limits and as low as reasonably achievable. Access controls to radiologically controlled areas were effective, and appropriate occupational exposure monitoring devices were provided and used.

R1.2 Radiological Controls-Radioactive Materials, Contamination, Surveys, and Monitoring

a. Inspection Scope (83750)

The inspector evaluated the effectiveness of PP&L's surveys, monitoring, and control of radioactive materials and contamination. The evaluation included a selective review of the adequacy and effectiveness of the following radioactive material and contamination control program elements:

- surveys and monitoring of radioactive material and contamination
- the calibration status of survey and monitoring equipment
- the proper use of personal contamination monitors and friskers
- the tracking of personnel contamination events and goals

- The inspector evaluated performance in the above selected areas via observation of work activities, tours of the RCA, discussions with personnel, review of documentation, and evaluation of applicable station procedures.

b. Observations and Findings

In general, radiological housekeeping conditions in the reactor and turbine buildings were acceptable. The inspector noted several examples of poor housekeeping practices in locked areas of the reactor and turbine buildings. Generally, radioactive material and radioactive waste were clearly labeled, segregated, and stored in an orderly manner.

PP&L implemented an effective radioactive material and contamination control program. Continuous air monitors were used in the RCA. A review of instrument calibration records indicated that the calibration program was implemented in accordance with procedures and only one minor discrepancy was noted.

Goals to assist in monitoring and tracking personnel and area contamination rates and percent recoverable contaminated area continued to be maintained and used to gauge the overall effectiveness of the station's programs in this area.

c. Conclusions

PP&L implemented effective surveys, monitoring, and control of radioactive materials and contamination. Health Physics technicians properly documented survey results. In general, radiological housekeeping conditions were acceptable.

R1.3 Radiological Controls-As Low As Reasonably Achievable (ALARA)

a. Inspection Scope (83750)

The inspector evaluated the effectiveness of PP&L's program to maintain occupational radiation exposure as low as is reasonably achievable. The evaluation included a selective review of the adequacy and effectiveness of the following ALARA program elements/documents:

- April 1999 HP Performance Indicator Report
- 1998 ALARA Assessment
- Draft Year 2000 Person-Rem Goal Breakdown
- HP Unit 2 (U2) Ninth Refueling and Inspection Outage (9RIO) Report
- Site ALARA Committee (SAC) Agenda for November 8, 1999

The inspector evaluated performance in the above selected areas via observation of work activities, tours of the RCA, discussions with personnel, review of documentation and station procedures.

b. Observations and Findings

The ALARA program continued to be well staffed and was being implemented in accordance with procedural controls. Post-job reviews were being used to generate exposure reduction plan (ERP) items for improving the ALARA effort. Annual and outage person-rem goals for the site were established, and person-rem goals for each work group were developed. On a regular periodic basis, actual person-rem accumulated for the site and for each work group was compared to the projections based on the established goals.

Lessons-learned from 1999 were being used in the development of the annual and outage goals for the year 2000. To this end, the Site ALARA Committee (SAC) established actions to improve dose control for the remainder of 1999 and was involved in the development of longer range exposure reduction activities including improved high radiation area controls and evaluation of remote monitoring methods. Additionally, the SAC initiated corrective actions to address long-standing employee concerns and exposure reduction plan items.

c. Conclusions

The ALARA program remains acceptable.

R7 Quality Assurance in RP&C Activities

a. Inspection Scope (83750)

The inspector evaluated the effectiveness of PP&L's self-identification and corrective action processes in the RP&C area. The evaluation included a selective review of the various surveillance, audit, and condition reports. The inspector also discussed the process with several cognizant personnel.

b. Observations and Findings

The Health Physics Program SRC/NAS Audit No. 99-007 was broad in scope and detailed. The seven Quality Surveillance Reports reviewed were detailed. Four assessments were reviewed which covered radiation protection management, external dose assessment, the vendor-provided TLD irradiation service, and a vendor-provided instrumentation service. The breadth varied, but each was detailed and resulted in recommendations for improvement.

Approximately 160 Radiological Protection condition reports were issued in the period from December 31, 1998 to November 22, 1999. A number of condition reports related to HP were reviewed and found to include low threshold items. The inspector found that for those HP condition reports reviewed, the issues were elevated to an adequate management level, evaluated, and adequately corrected. Additional inspection of PP&L's corrective action program is discussed in Inspection Reports 05000387/1999013 and 05000388/1999013.

c. Conclusions

PP&L's self-identification process in the area of radiation protection was generally effective.

S1 Conduct of Security and Safeguards Activities

a. Inspection Scope (81700)

Determine whether the conduct of security and safeguards activities met PP&L's commitments in the NRC-approved security plan (the Plan) and NRC regulatory requirements. The security program was inspected during the period of November 29 - December 3, 1999. Areas inspected included: alarm stations; communications; protected area (PA) access control of personnel, packages and vehicles.

b. Observations and Findings

Alarm Stations The inspector verified that the alarm stations were equipped with appropriate alarms, surveillance and communications capabilities. The inspector determined in interviews with the alarm station operators, that they were knowledgeable of their duties and responsibilities. The inspector also verified, through observations and interviews, that the alarm stations were continuously manned, independent, and diverse. The alarm stations did not contain any operational activities that could interfere with the execution of the detection, assessment, and response functions.

Communications The inspector determined by document reviews and discussions with alarm station operators, that the alarm stations were capable of maintaining continuous intercommunications and communications with each security force member (SFM) on duty and were exercising communication methods with the local law enforcement agencies as committed to in the Plan.

PA Access Control of Personnel, Vehicles, and Hand-Carried Packages and Material On November 30, and December 1, 1999, the inspector observed personnel and package search activities at the personnel access portal. The inspector determined that positive controls were in place to ensure only authorized individuals were granted access to the PA, that all personnel and hand-carried items entering the PA were properly searched and that vehicles entering the PA were properly controlled, and searched.

c. Conclusions

Security and safeguards activities with respect to alarm station controls, communications, and protected area access control of personnel, packages and vehicles were effectively implemented and met PP&L commitments and NRC requirements.

S2 Status of Security Facilities and Equipment

a. Inspection Scope (81700)

Areas inspected were: PA assessment aids, PA detection aids, personnel search equipment and testing, maintenance and compensatory measures.

b. Observations and Findings

PA Assessment Aids On December 2, 1999, the inspector assessed the effectiveness of the assessment aids by observing, on closed circuit television, two SFMs conducting a walkdown of the perimeter of the PA. The assessment aids had generally good picture quality and zone overlap. Additionally, to ensure Plan commitments are satisfied, PP&L had procedures in place requiring the implementation of compensatory measures in the event the alarm station operators are unable to properly assess the cause of an alarm.

Personnel and Package Search Equipment On December 1, 1999, the inspector observed both routine use and performance testing of PP&L personnel and package search equipment. The inspector determined that the search equipment performed in accordance with PP&L procedures and Plan commitments.

PA Detection Aids The inspector observed an SFM conducting performance testing of the perimeter intrusion detection system (PIDS). The testing consisted of intrusion attempts in numerous randomly selected zones during the camera walkdown. The appropriate alarms were generated in each attempt. The equipment was functional and effective and met the requirements of the Plan.

c. Conclusions

PP&L's security facilities and equipment were determined to meet their commitments and NRC requirements.

S3 Security and Safeguards Procedures and Documentation

a. Inspection Scope (81700)

Areas inspected were: implementing procedures and security event logs.

b. Observations and Findings

Security Program Procedures The inspector determined that the procedures were consistent with the Plan commitments, and were properly implemented and accomplished based on review of selected implementing procedures associated with PA access control of personnel, packages and materials, testing and maintenance of personnel search equipment, and performance testing of PA detection aids.

Security Event Logs The inspector reviewed the Security Event Logs for the previous twelve months. Based on this review, and discussion with security management, the inspector determined that PP&L appropriately analyzed, tracked, resolved and documented safeguards events that PP&L determined did not require a report to the NRC within 1 hour.

c. Conclusions

Security and safeguards procedures and documentation were properly implemented. Event Logs were properly maintained and effectively used to analyze, track, and resolve safeguards events.

S4 Security and Safeguards Staff Knowledge and Performance

a. Inspection Scope (81700)

Area inspected was: security staff requisite knowledge.

b. Observations and Findings

Security Force Requisite Knowledge The inspector observed a number of SFMs in the performance of their routine duties. These observations included alarm station operations, personnel, vehicle and package searches, and performance testing of the PIDS. Additionally, interviews of SFMs were conducted. Based on the responses, the inspector determined that the SFMs were knowledgeable of their responsibilities and duties and could effectively carry out their assignments.

c. Conclusions

The SFMs adequately demonstrated that they had the requisite knowledge necessary to effectively implement the duties and responsibilities associated with their position.

S5 Security and Safeguards Staff Training and Qualification

a. Inspection Scope (81700)

Areas inspected were security training and qualifications, and training records.

b. Observations and Findings

Security Training and Qualifications On December 3, 1999, the inspectors observed 7 randomly selected training and qualification (T&Q) records of SFMs. Physical and requalification records were inspected for armed and supervisory personnel. The results of the review indicated that the security force was being trained in accordance with the approved T&Q plan.

Training Records The inspector determined that the records were properly maintained, accurate, and reflected the current qualifications of the SFMs.

c. Conclusions

Security force personnel were being trained in accordance with the requirements of the T&Q Plan. Training documentation was properly maintained and accurate and the training provided by the training staff was effective.

S6 Security Organization and Administration

a. Inspection Scope (81700)

Areas inspected were: management support, effectiveness and staffing levels.

b. Observations and Findings

Management Support The inspector determined based on review of program implementation since the last program inspection, that adequate support and resources continued to be available to ensure program implementation.

Staffing Levels The total number of trained SFMs immediately available on shift met the minimum requirements specified in the Plan and implementing procedures. No performance issues were noted in the areas inspected.

c. Conclusions

Management support was adequate to ensure effective implementation of the security program, as evidenced by adequate staffing levels and the allocations of resources to support programmatic needs.

S7 Quality Assurance (QA) in Security and Safeguards Activities

a. Inspection Scope (81700)

Areas inspected were: audits, problem analyses, corrective actions and effectiveness of management controls.

b. Observations and Findings

Audits The inspector reviewed the annual physical security audit. The audit was thorough and in-depth. The audit identified 4 deficiencies. The deficiencies were related to administrative controls, and were minor documentation errors. None of the audit findings were indicative of programmatic issues.

Problem Analyses The inspector reviewed data derived from the security department's self-assessment program. Potential weaknesses were being properly identified, tracked, and trended.

Corrective Actions The inspector reviewed the corrective actions implemented by PP&L in response to the 1999 QA audit and self-assessment program. The corrective actions were technically sound and were performed in a timely manner.

Effectiveness of Management Controls PP&L had programs in place for identifying, analyzing and resolving problems. They included the performance of annual QA audits, a departmental self-assessment program and the use of industry data such as violations of regulatory requirements identified by the NRC at other facilities, as a criterion for self-assessment.

c. Conclusions

PP&L's audit program was being properly administered. In addition, the self-assessment program was being effectively implemented to identify and resolve potential weakness.

S8 Miscellaneous Security and Safeguards Issues

S8.1 (Closed) LER 50-387/99-005-00, Safeguards Event (71750, 92700)

On August 6, 1999, PP&L identified that an observation which inadvertently contained safeguards information had been distributed via an uncontrolled electronic mail (e-mail) system.

A review was conducted of PP&L's corrective actions associated with this event, addressing the dissemination of safeguards via company e-mail. It was determined that PP&L implemented appropriate compensatory measures, and corrective actions to preclude recurrence were acceptable. No violation of NRC requirements was identified. This LER is closed.

V. Management Meetings

X1 Exit Meeting Summary

A Region I security specialist presented the results of the Security and Safeguards program inspection to members of PP&L management at the conclusion of the inspection on December 3, 1999. PP&L acknowledged the findings presented.

A Region I health physics specialist presented the results of the Radiological Controls-External and Internal Exposure programs inspection to members of PP&L management at the conclusion of the inspection on December 10, 1999. PP&L acknowledged the findings presented.

The inspectors presented the inspection results to members of PP&L management at the conclusion of the inspection period, on January 7, 2000. PP&L acknowledged the findings presented.

The inspectors asked PP&L whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

INSPECTION PROCEDURES USED

IP 37551	Onsite Engineering Observations
IP 40500	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 61726	Surveillance Observations
IP 62700	Maintenance Program Implementation
IP 62707	Maintenance Observations
IP 71707	Plant Operations
IP 71750	Plant Support Activities
IP 81700	Physical Security Program for Power Reactors
IP 83750	Occupational Radiation Exposure
IP 92700	On Site Followup of Reports

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None.

Opened/Closed

None

Updated

None.

Closed

50-387/99-004-00	LER	Reactor Core Isolation Cooling (RCIC) Manually Isolated due to Failure of Steam Leak Detector Temperature Switch (Section O8.1)
50-387/99-005-00	LER	Safeguards Event (Section S8.1)

LIST OF ACRONYMS USED

CFR	Code of Federal Regulations
CR	Condition Report
CS	Core Spray
DCP	Design Change Package
EAL	Emergency Plan Action Level
EDG	Emergency Diesel Generator
° F	Fahrenheit
FSAR	Final Safety Analysis Report
IR	[NRC] Inspection Report
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LLRT	Local Leak Rate Test
LPCI	Low Pressure Coolant Injection
MSIV	Main Steam Isolation Valve
NCV	Non-Cited Violation
NDAP	Nuclear Department Administrative Procedure
NOV	[NRC] Notice of Violation
NRC	Nuclear Regulatory Commission
NUMARC	Nuclear Management and Resources Council
OD	Operability Determination
OSHA	Occupational Safety and Health Administration
PCO	Plant Control Operator
PCPR	Plant Component Problem Report
PP&L	Pennsylvania Power and Light Company
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
RPS	Reactor Protection System
RP&C	Radiological Protection and Chemistry
scfh	Standard Cubic Feet per Hour
SSCs	Structures, Systems, and Components
SSES	Susquehanna Steam Electric Station
TS	Technical Specification