**UNITED STATES**
**NUCLEAR REGULATORY COMMISSION**
REGION III
2443 WARRENVILLE ROAD, SUITE 210
LISLE, IL 60532-4352

December 17, 2013

Mr. Michael J. Pacilio
Senior Vice President, Exelon Generation Co., LLC
President and Chief Nuclear Officer, Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: DRESDEN NUCLEAR POWER STATION, UNITS 2 AND 3
NRC INITIAL LICENSE EXAMINATION REPORT 05000237/2013301; 05000249/2013301

Dear Mr. Pacilio:

On November 6, 2013, the U.S. Nuclear Regulatory Commission (NRC) completed the initial operator licensing examination process for license applicants employed at your Dresden Nuclear Power Station, Units 2 and 3. The enclosed report documents the results of those examinations. Preliminary observations noted during the examination process were discussed on October 28, 2013, with Mr. P. DiGiovanna and other members of your staff. An exit meeting was conducted by telephone on November 25, 2013, between Mr. R. K. Walton, Chief Operator Licensing Examiner, and Mr. P. DiGiovanna, to review the proposed final grading of the written examination for the license applicants. During the telephone conversation, NRC resolutions of the station's post-examination comments, initially received by the NRC on November 6, 2013, were discussed.

The NRC examiners administered an initial license examination operating test during the weeks of October 21 and October 28, 2013. The written examination was administered by both the NRC examiner and the Dresden Nuclear Station Training Department personnel on October 30, 2013. Six Senior Reactor Operator and three Reactor Operator applicants were administered license examinations. The results of the examinations were finalized on November 26, 2013. Three applicants failed the written examination and were issued a proposed license denial letter. Six applicants passed all sections of their respective examinations and two were issued senior operator licenses and two were issued operator licenses. Two senior operator licenses were being withheld pending completion of waivers.

The written examination will be withheld from public disclosure for 24 months per your request. However, since an applicant received a proposed license denial letter because of a written examination grade that was less than 80 percent, the applicant was provided a copy of the written examination and answer key. For examination security purposes, your staff should consider that written examination uncontrolled and exposed to the public.

In accordance with Title 10 of the *Code of Federal Regulations*, Section 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records System (PARS) component of NRC's Agencywide Documents Access and Management System (ADAMS). ADAMS is accessible from the NRC Website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

***/RA By M. Bielby Acting For/***

Hironori Peterson, Chief
Operations Branch
Division of Reactor Safety

Docket Nos. 50-237; 50-249
License Nos. DPR-19; DPR-25

Enclosures:
1. Operator Licensing Examination Report 05000237/2013301; 05000249/2013301 w/Attachment: Supplemental Information
2. Simulation Facility Report
3. Written Examination Post-Examination Comment Resolution

cc w/encls: Distribution via ListServ™

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

| | |
|---|---|
| Docket Nos: | 50-237; 50-249 |
| License Nos: | DPR-19; DPR-25 |
| Report No: | 05000237/2013301; 05000249/2013301 |
| Licensee: | Exelon Generation Company, LLC |
| Facility: | Dresden Nuclear Power Station, Units 2 and 3 |
| Location: | Morris, IL |
| Dates: | September 30 – October 3, 2013, Onsite Validation<br>October 21 – 30, 2013, Exam Administration<br>November 6, 2013, Received Post-Exam Comments<br>November 25, 2013, Exit Meeting |
| Inspectors: | R. K. Walton, Chief Examiner<br>D. McNeil, Examiner<br>C. Phillips, Examiner |
| Approved by: | H. Peterson, Chief<br>Operations Branch<br>Division of Reactor Safety |

## SUMMARY OF FINDINGS

ER 05000237/2013301; 05000249/2013301; 9/30/2013 – 11/26/2013; Exelon Nuclear Operations, Inc., Dresden Nuclear Power Station, Units 2 and 3; Initial License Examination Report.

The announced initial operator licensing examination was conducted by regional U.S. Nuclear Regulatory Commission (NRC) examiners in accordance with the guidance of NUREG-1021, Operator Licensing Examination Standards for Power Reactors, Revision 9, Supplement 1.

Examination Summary

Six of nine applicants passed all sections of their respective examinations. Two applicants were issued senior operator licenses and two applicants were issued operator licenses. Two licenses were being withheld until completion of exam waiver conditions. Three applicants failed the written examination and were issued proposed license denials. (Section 4OA5.1)

## REPORT DETAILS

4OA5 Other Activities

.1 Initial Licensing Examinations

a. Examination Scope

The U.S. Nuclear Regulatory Commission (NRC) examiners and members of the facility licensee's staff used the guidance prescribed in NUREG-1021, "Operator Licensing Examination Standards for Power Reactors," Revision 9, Supplement 1, to develop, validate, administer, and grade the written examination and operating test. The NRC examiners prepared the outline and developed the written examination and operating test with the assistance of the Dresden Nuclear Power Station training staff. The NRC examiners validated the proposed examination during the weeks of August 26, 2013, and September 30, 2013, with the assistance of members of the facility licensee's staff. During the onsite validation week, the examiners audited two license applications for accuracy. The NRC examiners, with the assistance of members of the facility licensee's staff, administered the operating test, consisting of job performance measures (JPMs) and dynamic simulator scenarios, during the weeks of October 21 and 28, 2013. The facility licensee and the NRC examiners administered the written examination on October 30, 2013.

b. Findings

(1) Written Examination

During four validations of the written examination, numerous questions were modified or replaced. Changes made to the written examination were documented in "Changes to Dresden 2013 Written Exam" which is available electronically in the NRC Public Document Room or from the Agencywide Documents Access and Management System (ADAMS) under ADAMS Accession Number ML13347B098. On November 6, 2013, post-examination comments for the written examination were hand-delivered to the chief examiner at the Region III office. Seven post-examination comments were provided by the licensee for consideration by the NRC examiners when grading the written examination. The written examination post-examination comments and the NRC resolution for the post-examination comments are available in Enclosure 3 of this report. The administered written examination and answer key are available electronically in the NRC Public Document Room or in ADAMS under ADAMS Accession Number ML13347B096 but will be withheld from public disclosure until December 1, 2015, as requested. However, since three applicants received proposed license denial letters because of a written examination grades less than 80 percent, the applicants were provided a copy of the written examination and answer key. For examination security purposes, the NRC considers the written examination as uncontrolled and exposed to the public.

The NRC examiners conducted a review of each missed question to determine the accuracy and validity of the examination questions. The NRC examiners graded the written examination on November 26, 2013.

(2) Operating Test

During validation of the proposed operating test, several JPMs were modified or replaced, and modifications were made to the dynamic simulator scenarios. One JPM was replaced because it was too time-consuming to be used. Some changes were made to the proposed simulator scenarios, correcting typographical errors, or adding operator actions on the panels to the scenario guides.

The NRC examiners completed operating test grading on November 12, 2013.

(3) Examination Results

Six applicants at the Senior Reactor Operator (SRO) level and three applicants at the Reactor Operator (RO) level were administered written examinations and operating tests. Six applicants passed all portions of their examinations. Three applicants failed the written section of the administered examination and were issued proposed license denial letters. The applicants were offered the opportunity to appeal any questions they believe were graded incorrectly.

.2 Examination Security

a. Scope

The NRC examiners reviewed and observed the licensee's implementation of examination security requirements during the examination validation and administration to assure compliance with Title 10 of the *Code of Federal Regulations*, Section 55.49, Integrity of Examinations and Tests. The examiners used the guidelines provided in NUREG-1021, "Operator Licensing Examination Standards for Power Reactors," to determine acceptability of the licensee's examination security activities.

b. Findings

No findings were identified.

4OA6 Management Meetings

.1 Debrief

The chief examiner presented the examination team's preliminary observations and findings on October 28, 2013, to Mr. P. DiGiovanna, Training Manager, and other members of the Dresden Nuclear Power Station Operations and Training Department staff.

.2 Exit Meeting Summary

The chief examiner conducted an exit meeting on November 25, 2013, with Mr. P. DiGiovanna, Training Manager, by telephone. The NRC's final disposition of the Dresden Nuclear Power Station's post-examination comments were disclosed and discussed during the telephone exit meeting. No proprietary or sensitive information was identified during the examination or debrief/exit meetings.

ATTACHMENT: SUPPLEMENTAL INFORMATION

## SUPPLEMENTAL INFORMATION

## KEY POINTS OF CONTACT

Licensee

D. Czufin, Site Vice President
H. Dodd, Regulatory Assurance Manager
P. DiGiovanna, Training Director
J. Nelson, Initial Licensing Exam Coordinator
G. Morrow, Senior Operations Supervisor

NRC

R. K. Walton, Chief Examiner

## ITEMS OPENED, CLOSED, AND DISCUSSED

Opened, Closed, and Discussed

None

## LIST OF ACRONYMS USED

| | |
|---|---|
| AC | Alternating Current |
| ADAMS | Agencywide Document Access and Management System |
| ADS | Automatic Depressurization System |
| CFR | Code of Federal Regulations |
| CRD | Control Rod Drive |
| DBA | Design Basis Accident |
| DEOP | Dresden Emergency Operating Procedures |
| DGP | Dresden General Procedure |
| DOA | Dresden Abnormal Operating Procedure |
| DOP | Dresden Normal Operating Procedure |
| ECCS | Emergency Core Cooling System |
| EDG | Emergency Diesel Generator |
| EHC | Electrohydraulic Control |
| EPA | Environmental Protection Agency |
| ER | Examination Report |
| ERV | Electromatic Relief Valve |
| FSAR | Final Safety Analysis Report |
| FWLC | Feedwater Level Control |
| HPCI | High Pressure Coolant Injection |
| IC | Isolation Condenser |
| JPM | Job Performance Measure |
| LOCA | Large Break Coolant Accident |
| LPCI | Low Pressure Coolant Injection |
| MWth | Megawatt (Thermal) |
| NGET | Nuclear General Employee Training |
| NRC | U.S. Nuclear Regulatory Commission |
| NSO | Nuclear Station Operator |
| OHS | Occupational Health Services |
| PARS | Publicly Available Records System |
| RO | Reactor Operator |
| RPV | Reactor Pressure Vessel |
| RWCU | Reactor Water Cleanup |
| SBO | Station Blackout |
| SOER | Significant Operating Event Report |
| SPR | Sudden Pressure Relay |
| SRO | Senior Reactor Operator |
| TBV | Turbine Bypass Valve |
| UFSAR | Updated Final Safety Analysis Report |

**SIMULATION FACILITY REPORT**

Facility Licensee: Dresden Nuclear Power Station, Units 2 and 3

Facility Docket No: 50-237; 50-249

Operating Tests Administered: October 21 – 28, 2013

The following documents observations made by the NRC examination team during the initial operator license examination. These observations do not constitute audit or inspection findings and are not, without further verification and review, indicative of non-compliance with 10 CFR 55.45(b). These observations do not affect NRC certification or approval of the simulation facility other than to provide information which may be used in future evaluations. No licensee action is required in response to these observations.

During the conduct of the simulator portion of the operating tests, the following items were observed:

| ITEM | DESCRIPTION |
|---|---|
| Operator's Computer Station | During the crew's initial walkdown of the panels prior to scenarios on day two, the operators noted that the operator's computer consoles were locked up. The licensee repaired the condition before the scenario started. |
| Feedwater Level Controllers (FWLC) Failed | During the first scenario of day two, during the major event, the FWLC failed to receive operator commands. The panel indications did not match actual (simulator) conditions. The licensee could not duplicate the condition. This condition did not recur. |
| Drywell pressure | During the crew's initial walkdown of the panels prior to scenarios, drywell pressure rose without any input. Operators were cleared from the simulator, the simulator was reset and the condition did not repeat. |
| Control Rod Drive (CRD) Pump trip | At the end of a scenario, the CRD pump inexplicably tripped requiring operator actions. The licensee identified that the simulator was programmed to clog the CRD suction filters during extended simulator run times. This condition was corrected by the licensee. |

**RO Question 9:**

Unit 2 is in MODE 3 with the following set of conditions:

- One turbine bypass valve is full open
- RPV water temperature at 316°F and slowly lowering
- RPV pressure is 245 psig, slowly lowering
- 2B Recirc pump is running at minimum speed
- 2A EHC Pump is out of service

Then an overcurrent condition occurs on Bus 27.

For these conditions, what is the preferred method of heat removal from the RPV?

a. Open an additional turbine bypass valve fully

b. Place Isolation Condenser System in service per DOP 1300-03

c. Initiate HPCI System in pressure control mode per DOP 2300-03

d. Alternate opening of Electromatic Relief Valve(s) at five minute intervals

**ANSWER: B**

Applicant's Contention:

Based on the information provided, the isolation condenser would not be able to provide adequate heat removal and be able to control reactor pressure. The question stated that 1 TBV was full open. Per DGP 02-01 page 64, one TBV is worth 112.5 MWth and the Isolation Condenser is worth 74 MWth. Based on the information provided in the question, the Isolation Condenser would not be able to control reactor pressure due to the amount of energy being dissipated. With this in mind, the ADS valves would be the only pressure control source able to dissipate the required amount of heat to maintain the current conditions. Additionally, per DOA 1000-01 step D.6 states, “Then use one or more of the following ECCS alternatives as directed by the Unit Supervisor to control reactor water temperature/pressure.” The ADS valves being the only single option with enough capacity to dissipate the required heat load. Based on the above information, choosing the ADS valves was the only correct answer.

Facility Position:

Based on the initial conditions given in the stem of the question, the Isolation Condenser alone would not be enough to continue the current trend of reducing reactor pressure. The information provided in the question indicates that one Bypass Valve is full open. This approximates to 112 MWth of heat removal per DOA 1000-3. This DOA also provides the MWth capacity for all other available systems as follows:

- Isolation Condenser – 74 MWth
- HPCI – 37 MWth
- ERV – 140 Mwth

Also consider that DOP 1300-03, Step F.8 delineates "preferred order of systems to be used for RPV pressure control." This is merely a preferred order ONLY and does not reflect the best choice of system for a given set of plant conditions. The question requires the operator to interpret the condition and chose the appropriate system.

In this event ~112 MWth of heat capacity needs to be removed. DOP 1300-03, Step F.8 preferred system use criteria would be utilized, in order, per below:

- Isolation Condenser (74 MWth) would be evaluated as a first choice and discounted due to insufficient heat removal capacity.
- HPCI in pressure control mode (37 MWth) would be evaluated as a second choice and discounted due to insufficient heat removal capacity.
- ERVs (140 MWth) would be evaluated as the next choice and determined to have a suitable heat removal capacity for the given plant conditions.

The candidate's conclusion that the thermal capacity of the Isolation Condenser is not enough to make up for the loss of the turbine bypass valve going shut is supported by the above facts. These facts also support that the preferred order of DOP 1300-03 system for RPV pressure control does not account for the necessary heat removal capacity to support the continuation of the cooldown in progress. Alternate opening of the Electromatic Relief Valve(s) during the five minute intervals is the only available option with the capacity of removing the heat load that will allow a continued coodown.

The facility supports changing the correct answer for question #9 to (D) "alternate opening of the Electromagnetic Relief Valve(s) at five minute intervals."

References:

DOA 1000-3
DOP 1300-3

NRC Resolution:

This NRC exam question was modified from licensee Bank Question Q22591. In the bank question, plant conditions were similar to the test question except that SDC was lost in lieu of the TBV and steady RPV temperature/pressure conditions existed in lieu of a slight cooldown in the test question. The bank question asked, "What action(s) is/are required to be taken to MAINTAIN the *current* RPV water temperature?" In order to "MAINTAIN the *current* RPV water temperature," the heat removal from the lost TBV (112 MWth from rated conditions) could be equaled by use of an ERV (140 MWth from rated conditions). The heat removal from the alternative methods (HPCI, IC and RWCU) could not equal heat removal from the TBV. Hence to keep water RPV water temperature stable, the answer to the bank question was to use the ERVs.

In its supporting statement, the licensee concurs with changing the answer to Question #9 to "D" citing heat removal capabilities from various systems in Table 1 of DGP 02-01 that are from normal operating conditions. However, the conditions provided in the stem, Mode 3 operations, are several hours after a shutdown from rated conditions.

In Mode 3, all systems listed in Table 1 will have reduced heat removal capabilities than shown. The NRC understands the values in Table 1 do not directly reflect the conditions described in the question, but Table 1 can be used to compare relative heat removal capabilities. The licensee cites that the IC system does not have the heat removal capabilities as does the ERV's and that placing the IC system in service would not support the continuation of the cooldown in progress. However, the exam question asked the preferred method of heat removal unlike the bank question which was trying to maintain RPV water temperature stable. The NRC concurs that with IC in service, the cooldown may be reduced and may even result in a slight heat up over time. However, this condition would not result in an unintended Mode change. As such, an increase in RPV temperature/pressure for the test question is inconsequential.

The test question asked, "What is the preferred heat removal method from the RPV?" The examiners determined, based on multiple technical reviews and validations by the facility training and licensed operator staff, that the alternate preferred method of heat removal was referenced in DOP 1300-03, Step F8 and DOA 1000-01, Step D6. Both of these references list, in order, the isolation condenser system, high pressure coolant injection, and Electromatic Relief Valves (ADS Relief valves in DOP 1300-01).

The test question did not put a restriction on maintaining current RPV water temperature as did the bank question. Only two applicants correctly answered the IC as being the preferred alternative method of heat removal. The remaining applicants answered with the ERV being the preferred method. The NRC believes that most of the applicants answered this question based on their knowledge of the bank question rather than their knowledge of the preferred order of alternative heat removal methods as listed in the above references.

The NRC determined that the isolation condenser is the correct answer for the plant conditions provided in the stem of the question. The use of the isolation condenser may not have the heat removal capacity as the ERV's and there may be a subsequent heat up of the RPV as the IC is placed in service, but the NRC determined the use of the IC system to be more desirable (as listed in the references). Use of the ERV's would result in an inventory loss to the RPV requiring the use of a makeup system; the suppression pool would heat up requiring cooling. Additionally, the IC system would be more reliable than use of the ERV's as the ERV's are more prone to failure (i.e., sticking open).

As such, the NRC concluded that the only correct answer to Question #9 is "B."

**RO Question 15:**

With Unit 3 in Mode 1 operations, the torus conditions are as follows:

- Torus water temperature is 92°F and rising slowly
- Torus narrow range water level is -5.0 inches and lowering slowly

Should a LOCA occur during these conditions, what is the FIRST concern operators would have for primary containment?

a. Incomplete steam condensation

b. Insufficient scrubbing of iodine from steam discharged during a LOCA

c. Condensate oscillation and chugging loads

d. Excessive clearing loads from steam discharges and pool swell could result in damage to the torus and its supports

**ANSWER: A**

Applicant's Contention:

Per the Technical Specification Bases for 3.6.2.2, the background section states the following: "If the suppression pool water level is too low, an insufficient amount of water would be available to adequately condense the steam from the relief valves quenchers, downcomer lines, or HPCI turbine exhaust line. Low suppression pool water level could also result in an inadequate emergency makeup water source to the Emergency Core Cooling System. The lower volume would also absorb less steam energy before heating up excessively. Therefore, a minimum suppression pool water level is specified." However, it later states in Actions A.1, "With suppression pool water level outside the limits, the conditions assumed for the safety analysis are not met. If water level is below the minimum level, the pressure suppression function still exists as long as the downcomers are covered, HPCI turbine exhaust is covered, and relief valve quenchers are covered." Based on the current conditions provide in the question, the downcomers, HPCI turbine Exhaust and relief valve quenchers are still covered (level is only ½-inch outside of the allowable band).

Prior to the LOCA, DEOP 200-01 would have been entered based on the torus level of -5.0 inches and dropping slowly, Without further information (i.e., source of dropping level), it is plausible that torus makeup would have been initiated per DOP 1600-02, step G.2 per the first step in DOP 200-01 based on this entry condition.

When the LOCA occurs, the SRO would eventually enter DEOP 100 and reenter DEOP 200-01 (due to rising drywell pressure and subsequent scram that would occur). When DEOP 200-01 is re-entered all 5 legs are re-entered concurrently. The LOCA will cause Drywell pressure to rise at some rate (dependent on the size of the leak). With rising drywell pressure, the SRO would prioritize entry into the Primary Containment Pressure Leg of DEOP 200-01 since torus level would already be addressed by the initial entry of DEOP 200-01. With an active LOCA, the first step of DEOP 200-01 Primary Containment pressure leg would not be utilized since you have changing conditions within the Drywell and would need activity samples prior to venting in this step. The SRO would direct initiation of torus sprays to try and control drywell pressure,

however the pressure suppression function still exists in this condition and there should be no bypass flow with torus level at approximately 14 feet, so torus sprays would have little effect on reducing Drywell Pressure. Drywell Pressure would continue to rise. Due to this continued rise, the concern would be chugging that would occur at 9 psig. Based on the above information, it is plausible that chugging would be the FIRST concern as well as lack of Steam Condensation as selected for the correct answer.

Facility Position:

The question is acceptable as written for this exam. The assumptions made in the feedback from the candidate would occur sometime after the conditions given in the stem of the question and therefore would not be the FIRST concern as stated in the call of the question.

References:

ARP-7, Window 42, Revision. 71
E-Prints E-17, Sheet 3 (Revision. 18), and Sheet 4 (Revision. 17)
DOS 1600-16, Suppression Chamber Water Level Correction, Figure 1
DEOP 200-01, Primary Containment Control

NRC Resolution:

The question asked what concerns there would be for Mode 1 operations with the conditions given in the torus should a LOCA occur. The applicants were to know that torus temperature was not the initial concern but that a low torus water level and level continuing to lower was the issue.

In its contention, the applicant noted that with the given conditions, the downcomers were still covered with torus level being ½-inch below the allowable band. The applicant assumed entry into procedures to makeup to the torus and then described the crew's actions and primary containment response to a LOCA. Although the actions taken by the crew and the response to containment by the LOCA may be as the applicant describes, the question asked what "is the FIRST concern" with the torus. The intent of this question was not to evaluate the long term effects of a primary containment outside of its design, nor to evaluate crew implementation of the emergency procedures, but to evaluate the initial concern of the torus with a low water level and an adversely trending condition.

The applicant described that with the downcomers being covered by water, the pressure suppression function of the torus was still met. This may be true, but during the containment response to a LOCA, with steam being discharged through the downcomers and low pressure pumps drawing suction from the torus for containment pressure suppression, the torus level would become agitated and could result in conditions where steam discharges to the torus may not be adequately condensed. Hence, the Technical Specifications and DEOP 200-01 specify a torus level band to maintain. DEOP 200-01, Primary Containment Control, requires torus level be maintained between > -4.5 inches and < -1.5 inches. The condition given in the question was below the allowed band; a condition requiring entry into DEOP 200-01 and Technical Specification 3.6.2.2.

Lesson Plan DRE223LN001, Section II.I, described that the minimum torus water level was to ensure that full condensation occurred to steam exhausted into the torus. Hence, 'A' was determined to be the correct answer. The applicant believed that distractor 'C' was also correct

based on the containment response to a LOCA. This condition would be considered true for high torus temperature conditions. A high torus temperature condition did not initially exist.

Although the applicant's contentions of procedure entry and containment response to a LOCA signal may be correct, the applicant's contentions did not change the parameters of the originally stated question. A low torus level, a level below DEOP 200-01 band, is a concern to ensure full condensation of steam discharged into the torus.

The correct answer for Question 15 remains as 'A.'

**RO Question 18:**

Unit 3 was operating at rated power when a loss of coolant accident occurred that caused a fuel element failure. Coincident to this, containment has failed.

If members of the public downwind were to receive an acute dose of 150 rem, what biological effects are expected to occur?

1. Death (to 50% of the population)
2. Slight decrease in blood cell count
3. Nausea/vomiting to <50% of population within 3 hours
4. Loss of hair after 2 weeks

a. 2 ONLY

b. 2 AND 3 ONLY

c. 2, 3 AND 4 ONLY

d. 1, 2, 3 AND 4

**ANSWER: B**

Applicant's Contention:

A table excerpted from the U.S. EPA Website using the following address was provided:
http://epa.gov/radiation/understand/health_effects.html

Facility Position:

The question is acceptable as written for this exam. Answer provided is in alignment with Exelon NGET study material and NRC Regulatory Guide 8.29.

References:

Dose Exposure Chart from EPA Website
NGET Training, July 2013, page 96 of 141
Regulatory Guide 8.29, Revision 1

NRC Resolution:

The question as originally written was to evaluate the health effects of the general population if they were to receive 150 rem of radiation exposure (acute). The licensee's reference material included:

- Slight blood changes at 25 – 100 rem
- Vomiting in 5% – 50% of the population within 3 hours for exposures of 100 -200 rem
- Loss of hair after 2 weeks with exposures of 200 – 600 rem
- Death to 0% - 80% of the population within 2 months for exposures of 200 to 600 rem

The licensee's reference generally agreed with information in Regulatory Guide 8.29, "Instructions Concerning Risks from Occupational Radiation Exposure," Revision 1. With 150 rem of exposure, slight blood changes and vomiting would be expected. Hence, 'B' was determined to be the correct answer.

The applicant identified a reference from the EPA website that included the following information:

- Changes to blood chemistry with 5 – 10 rem exposure
- Vomiting with 70 rem exposure
- Hair loss within 2 – 3 weeks with 75 rem exposure
- Possible death within 2 months with 400 rem exposure

Based on information provided by the EPA website, the applicant believed that distractor 'C' also should be accepted as a correct answer since hair loss was considered to be a valid symptom with exposure of 75 rem; within the 150 rem stipulated in the question.

Additionally, the licensee's NGET training stated loss of hair would occur after 2 weeks with 200 – 600 rem exposure and Regulatory Guide 8.29 stated a loss of hair will occur with dose between 300 – 500 rad. Dose to the public and dose to occupational workers should produce the same consequential symptoms for the same exposure. The NRC cannot understand the discrepancy in dose exposures for the symptom of loss of hair as included in the references.

Although the NRC regulates radiation exposure to workers in the industry, the EPA is responsible for regulating radiation exposure to the general public. Therefore, the NRC cannot refute the information that maybe contained in the EPA references. It is also understood that the question was developed and validated based on licensee-approved procedures and NRC Regulatory Guide, which correspondingly supports 'B' as the correct answer. However, since the question asked what the effect would be for radiation exposure to members to the public, the NRC must also accept the reference material from the EPA as being valid.

As such, the answer to Question 18 using existing licensee and Regulatory Guide reference material for radiation workers is 'B.' The answer to Question 18 using the EPA reference material for radiation exposure to the public is 'C.' The NRC accepts both of these answers as being correct for Question 18.

**RO Question 32:**

Which of the following combinations of ECCS subsystems will ensure adequate core cooling during a DBA LOCA?

a. One LPCI subsystem

b. One Core Spray subsystem

c. One Core Spray subsystem AND the 5 ADS valves

d. One Core Spray Subsystem AND one LPCI subsystem

**Answer: D**

Applicant's Contention:

Per DEOP 0010, adequate core cooling is defined as "heat removal from the reactor sufficient to prevent rupturing the fuel clad." Three viable mechanisms for establishing adequate core cooling exist – core submergence, spray cooling and steam cooling. Adequate spray cooling is "provided, assuming a bounding axial power shape, when design spray flow requirements are satisfied and RPV water level is at or above the elevation of the jet pump suctions (Core Spray flow> 4750 gpm AND reactor water level > -191 inches). The covered portion of the core is then cooled by submergence while the uncovered portion is cooled by the spray flow." Additionally, in section 6.3.3.3.2 of the UFSAR "Long term cooling requirements for a large break are met by either: 1) supplying 4500 gpm or core spray flow to the top of the core and maintaining 2/3 core height." Based on the above information, one division or core spray is an acceptable answer to the question as well.

Facility Position:

The question is acceptable as written for this exam. The statements made in DEOP 0010 do not consider a DBA LOCA when describing viable mechanisms for core cooling. The correct answer is supported by Dresden Station FSAR 6.3.

Reference:

UFSAR, Section 6.3

NRC Resolution:

The applicant referenced DEOP 0010 and UFSAR 6.3.3.3.2 in his argument that, "Long term cooling requirements for a large break are met by either: 1) supplying 4500 gpm or core spray flow to the top of the core and maintaining 2/3 core height";(or 2) flooding the core to a level above the top of active fuel.) The NRC agrees that adequate long term core cooling can be met under these conditions.

However, the question asked, which "… combinations of ECCS subsystems will ensure adequate core cooling during a DBA LOCA." Per UFSAR 6.3.3.1.1, "... either two core spray subsystems or one core spray subsystem and two LPCI pumps are required to ensure adequate core cooling following a DBA LOCA." Distractor 'D' was originally selected as the correct

answer, (one core spray subsystem AND one LPCI subsystem) since this met the design as stated in UFSAR 6.3.3.1.1. The same UFSAR paragraph on page 6.3-24 references UFSAR Section 6.3.3.3.2 for core spray long term cooling requirements.

The question asked for combinations of ECCS subsystems needed during a DBA LOCA and not ECCS requirements for long term cooling. The NRC does not accept the applicant's contention. The answer to Question 32 remains as originally stated. Answer 'D' is the only correct answer.

**RO Question 43:**

Unit 3 was operating at rated power when a transient occurred, resulting in the following conditions:

- RPV water level is -72 inches and trending up.
- The TR-32 Sudden Pressure Relay (SPR) activated.
- The Unit 3 EDG started but its output breaker subsequently tripped on over-current.

The Unit Supervisor has directed the crew to enter and execute DGA-12, PARTIAL OR COMPLETE LOSS OF AC POWER.

The required electrical lineup is to power Bus 33-1 from __(1)__ and Bus 34-1 from __(2)__ .

| | (1) | (2) |
|---|---|---|
| a. | Bus 23-1 | U3 SBO |
| b. | U3 SBO | Bus 24-1 |
| c. | 2/3 EDG | U3 SBO |
| d. | 2/3 EDG | Bus 24-1 |

**Answer: C**

Applicant's Contention:

What caused the EDG output breaker to trip on overcurrent? Was 34-1 overcurrent? You would not power a bus that is overcurrent. No correct answer given.

Facility Position:

With the conditions given in the stem of the question, the Unit 3 EDG has an auto start signal present via Div II Core Spray Logic due to RPV level below -59 inches. With an auto start signal present, the Unit 3 EDG Auto Start Relay (ASR-3/"HGA") is picked up. This ASR-3 relay, when picked up, has the effect of bypassing all trips of the Unit 3 EDG output breaker, with the exception of a Differential Current. The trips that are bypassed are: Over-current, Reverse Power, Ground Fault, Loss of Field, and Under Frequency. The stem indicates that a Unit 3 EDG output breaker subsequently tripped on over-current which, by Station Design is bypassed under the conditions given in the question.

If the Unit 3 EDG output breaker did trip on over-current when it should not have (i.e., when an auto start signal was present), then the status of Unit 3 EDG output breaker and Bus 34-1 electrical protection scheme is in an unknown and potentially unreliable condition. With Division one of AC power energized via the 2/3 EDG concurrent with RPV level well above Top of Active Fuel and rising, the risk of re-energizing this Bus with no pressing Public Health & Safety concern is unacceptable (H. B. Robinson, SOER 10-2 Event). Therefore, the correct course of action would be to energize Bus 33-1 from the 2/3 EDG and leave Bus 34-1 de-energized until evaluated.

The licensee recommends removing this question due to no correct answer.

References:

DGA-12, Partial or Complete Loss of AC Power
Electrical prints 12E-3350B; 12E-3346, Sheet 2

NRC Resolution:

The following conditions existed in the stem of the question:

- ECCS signal present (RPV water level at -72 inches) and
- 3 EDG output breaker tripped on over current condition

The first condition would generate a signal to the ASR-3 relay which prevents various EDG output trips from actuating. One such trip bypassed by this relay is the EDG output breaker over current trip. So the second condition should not occur. The NRC reviewed the electrical prints provided by the licensee. The ASR-3 relay inhibits the EDG output breaker trip with an ECCS signal present (RPV water level at -72 inches). The NRC concurs with the licensee's position with one division of AC power energized (Bus 33-1 powered from the 2/3 EDG) and without a pressing Public Health & Safety concern, that the correct course of action would be to leave Bus 34-1 de-energized until evaluated.

After reviewing the references provided by the applicant and the licensee's position, the NRC concurs that there is no correct answer to this question.

Question 43 will be removed from the exam.

**SRO Question 79:**

Unit 3 was operating at full power when an event occurred. Later during the accident, the following plant conditions exist:

- HPCI pump is out-of-service
- LPCI pumps running but NOT injecting to the RPV
- "A" & "B" Trains of Core Spray are injecting into the RPV at 4000 gpm each
- RPV Water level is -45 inches and steady
- Drywell pressure is 7 psig and rising slowly
- Drywell temperature is 240°F and rising slowly
- Torus Bulk Temperature is 200°F and steady
- Torus Level is 14 feet and steady
- Torus Bottom Pressure is 10.2 psig and rising slowly

The SRO is performing steps from DEOP 100, "RPV Control" and DEOP 200-01, "Primary Containment Control." To spray the drywell, AND to prevent ECCS pump cavitation the SRO orders…

a. spray with one LPCI pump with flow <2750 gpm

b. reduce CS flow to <2750 gpm, then inject with one LPCI pump at 4000 gpm

c. the drywell can NOT be sprayed without cavitating existing ECCS pump flow

d. secure one CS pump before injecting with one LPCI pump, keep LPCI flow <4000 gpm

**ANSWER: A**

Applicant's Contention:

Based on the information in the question, not being able to avoid cavitation is the correct answer. First, the LPCI Drywell Spray valves (3-1501-27(8) A/B) are not throttleable valves and are upstream of the LPCI Injection valves 3-1501-21A/B which are throttleable. The only way to throttle LPCI flow in this configuration is to throttle a valve that is not normally used for this purpose (i.e. manually manipulating a LPCI pump discharge valve of the Drywell Spray valves themselves.) There is no procedural guidance to perform this action. The only other way to limit drywell spray flow is open other flow paths to divert flow away (i.e., torus cooling). Performing this action would increase overall flow to over 10750 gpm, which causes the use of the "X" Curve of DEOP 200-01. When the "X" Curve is utilized, there are no pump flows at 200°F Torus Bulk temperature and 10.2 psig torus bottom pressure that would prevent cavitation from occurring.

Second, if flow is able to be achieved at 2750 gpm, the SRO would utilize the "W" Curve. At initial conditions, 200°F torus temperature and 10.2 psig torus bottom pressure, no cavitation would occur the instant you put on drywell sprays, however due to the evaporative cooling that would occur with initiation drywell sprays, pressure would rapidly reduce to below 10 psig. As soon as you drop below 10 psig torus bottom pressure, you would then transfer to the 5 psig line on Curve "W" since interpolation is not allowed. With the 5 psig torus bottom pressure

being your limiting curve, and torus temperature of 200°F, there is no way to prevent cavitation from occurring since there are no flows existing within the curve at this temperature.

Facility Position:

As administered, the correct answer (A) to this question was to spray the Drywell with LPCI pump flow less than 2750 gpm to prevent cavitation. The candidate is correct that the drywell spray valves utilized to establish these conditions are either full open or full closed valves and do not have throttle capability. In addition, the training staff utilized the plant reference simulator to determine if different LPCI system lineups and/or pump combinations would facilitate initiation of drywell spray to meet the condition of 2750 gpm flow. The best possibility of achieving such conditions would require the drywell spray function to be limited to one division of drywell spray, with the LPCI cross tie valves closed, and ONLY one LPCI pump running in that division. Under these conditions, drywell spray was still in excess of 4000 gpm. This amount of flow, when coupled with the core spray injection flow of 8000 gpm, now risks ECCS pump cavitation per DEOP 200-01, Figure "W."

Also note that the lineup of a single LPCI pump in the division performing the DW spray function is a contradiction to the information provided that states, "LPCI pumps are running but NOT injecting into the RPV." This adds further support to the candidate's position.

Based on the above findings, no method exists to spray the drywell that would maintain a necessary margin to prevent ECCS pump cavitation (reference DEOP 200-01, Figure "W"). As a result, selection (C) is the only possible correct answer. The station supports the position of the candidate and recommends changing the correct answer for Question 79 to (C), "the drywell can NOT be sprayed without cavitating existing ECCS pump flow."

Reference:

DEOP 200-01, Primary Containment

NRC Resolution:

The question as originally written by the NRC and validated by the facility was to have applicants apply knowledge of Figure W of DEOP 200-01 to determine how much drywell spray flow to apply without cavitating the ECCS pumps. With deteriorating conditions in the torus, the author selected conditions that would require a drywell spray flow rate from LPCI of <2750 gpm. The answer was predicated on the belief that LPCI flow to the drywell was throttleable. The applicant's observation that LPCI flow to the drywell was not throttleable was confirmed by the licensee. With the given conditions and the need to spray the drywell, the licensee confirmed by using the plant reference simulator that spraying the drywell with LPCI would result in cavitation of ECCS pumps.

Additionally with LPCI pumps running (a given condition) and the other containment parameters given, if drywell spray was initiated, all 4 LPCI pumps would provide flow necessitating use of Figure X of DEOP 200-01. This figure also results in ECCS pumps operating in a cavitation condition. Also, with torus bulk temperature constant and after spraying the drywell, torus bottom pressure would lower quickly resulting in a more severe cavitation condition.

Based on information provided by the applicant and the licensee, the NRC concurs that since the drywell spray cannot be throttled, then there is no condition that can exist without cavitation

of the ECCS pumps occurring. Distractor ‘C’ stated, “the drywell can NOT be sprayed without cavitating existing ECCS pump flow.”

The NRC changes the correct answer for Question 79 from ‘A’ to ‘C.’

**SRO Question 98:**

As the SRO for a shift, you are in the third quarter and have to decide which NSO can substitute for an NSO who had to leave in the middle of your shift. Your present NSO has a "no-solo" license with no other restrictions. From this available list provided, who is eligible for the 2nd NSO position on your crew?

John – reactivated his license in the 1st quarter, but did NOT stand a watch as an NSO in the 2nd quarter

James – has reported to the medical staff last week a condition requiring a reduction of dosage of a prescription drug he is currently taking. A license change has been submitted to the NRC for review

Julia – has a "no-solo" license and is a declared pregnant worker

a. Julia ONLY

b. James ONLY

c. James and Julia

d. John & James

**ANSWER: C**

Applicant's Contention:

The correct answer to the question was that both James and Julia were able to assume the shift. However, choosing just Julia is also a correct answer. On ES-605, page 10, the following is stated: "Physician prescribed changes in medication or dosing for an existing medical condition are not required to be reported to the NRC, unless the examining physician believes the operator's medical condition has become unstable (therefore requiring follow-up medical status reports to the NRC) or that operator requires a no-solo license restriction." Additionally, per OP-AA-105-101, Section 4.6, a licensed individual is required to "report the use of prescription or over the counter medications, other than aspirin, aspirin substitute, antibacterial, and birth control to their immediate supervisor and OHS in accordance with SY-AA-102-106." OP-AA-105-101 states further in 4.6.5.1 that "OHS shall EVALUATE information provided by the Licensee, and based on the evaluation may place the Licensee's license on "Administrative Hold" pending further evaluation of the condition." Since the change in prescription was reported to the NRC, it is plausible that James has been put on Administrative Hold (defined as an administrative restriction placed upon a NRC Licensed Operator by OHS restricting the license from performing licensed duties pending further evaluation of a health status change.) Further information would be required (i.e., what the medication was, why is it changed, etc.) to fully ascertain whether James could assume the shift or he had been placed on Administrative Hold. Based on this information, picking Julia is also a plausible and correct answer.

Facility Position:

The question provides inadequate information concerning the required OHS evaluation for an administrative hold. To select the correct answer (C), the candidates must make an assumption that "James" is not on administrative hold AND that his condition has been evaluated by the Station's Occupational Health Services (OHS) representative.

OP-AA-105-101 (Administrative Process for NRC License and Medical Requirements) and the Dresden OHS representative were utilized for additional insights. OHS indicated that there are reasonable cases where a reduction in dosage of a medication would require a "stabilizing period" to ensure that any effects would not adversely impact the Operators ability to perform shift functions. This insight further supports the candidates' position that the OP-AA-105-101, step 4.6.5.1 requirement to evaluate this condition may already preclude this individual from being able to perform shift functions.

Based on the above findings, there are clear circumstances here both (A) and (C) are correct. Selections (B) and (D) are valid distracters and can never be true due to inclusion of "John" who holds an inactive license. The station supports the position of the candidate in adjusting the answer for Question 98 to indicate both (A) and (C) as correct choices.

References:

OP-AA-105-101, "Administrative Process for NRC License and Medical Requirements"

NRC Resolution:

Federal Regulations would typically not require a reduction in a prescribed medication to result in a licensed operator from being suspended from licensed activities. However, the licensee's doctor or site nurse can administratively suspend an individual from licensed duties based on their medical opinions of the operator's medical condition.

OP-AA-105-101, step 4.6.5.1 requires, "OHS EVALUATE the information provided by the Licensee, and based on the evaluation may place the license on "Administrative Hold." The next substep states that, "OHS shall NOTIFY the licensee and the license Coordinator if an individual's license is placed on "Administrative Hold." The following substep states that, "OHS shall NOTIFY the Operations Support Manager to remove the individual from license duties." Step 4.6.6 states that, "Changes in license status must be reported to the NRC within 30 days."

The question stated that James "has reported to the medical staff last week a condition requiring a reduction of dosage of a prescription drug he is currently taking. A license change has been submitted to the NRC for review." This indicates that step 4.6.6 of OP-AA-105-101 has been completed. The previous step, Step 4.6.5, must also have been completed. For James' condition in the question, there was no mention that he was placed on administrative hold, (a condition of step 4.6.5). This indicates that the procedure was followed:

- James was evaluated last week by the medical staff (Step 4.6.5.1)
- There were no (internal) notifications made (Step 4.6.5.1 A and B)
- The NRC was notified (Step 4.6.6)

The applicant stated, "Since the change in prescription was reported to the NRC, it is plausible that James has been put on Administrative Hold." This would be true if OP-AA-105-101 was not

followed. Specifically, that internal notification of Steps 4.6.5.1 A and B, were not completed nor implemented prior to performing step 4.6.6. Since Step 4.6.6 was completed, and we understand that OP-AA-105-101 was implemented as required, that any internal notifications were completed (if James was placed on Administrative Hold) and would be so stated in the condition statement for James in the question stem. If James was placed on administrative hold, and OP-AA-105-101 was followed, then internal notifications would have been made and so included in the condition statement for James in the question stem.

The applicant incorrectly assumed that James was placed on administrative hold. If James had been placed on administrative hold AND OP-AA-105-101 was followed, then notifications would have been made and included in the stem of the question for James.

The correct answer to Question 98, as originally validated by the licensee, remains ‘C.’

In accordance with Title 10 of the *Code of Federal Regulations*, Section 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records System (PARS) component of NRC's Agencywide Documents Access and Management System (ADAMS). ADAMS is accessible from the NRC Website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

***/RA By M. Bielby Acting For/***

Hironori Peterson, Chief
Operations Branch
Division of Reactor Safety

Docket Nos. 50-237; 50-249
License Nos. DPR-19; DPR-25

Enclosures:
1. Operator Licensing Examination Report 05000237/2013301; 05000249/2013301 w/Attachment: Supplemental Information
2. Simulation Facility Report
3. Written Examination Post-Examination Comment Resolution

cc w/encls: Distribution via ListServ™

DISTRIBUTION w/encl:
Brett Rini
RidsNrrDorlLpl3-2 Resource
RidsNrrPMDresden Resource
RidsNrrDirsIrib Resource
Cynthia Pederson
Anne Boland
Steven Orth
Allan Barker
Carole Ariano
Linda Linn
DRPIII
DRSIII
Patricia Buckley
Tammy Tomczak

DOCUMENT NAME: DRES ER 2013 301 (RKW).docx
☒ Publicly Available ☐ Non-Publicly Available ☐ Sensitive ☒ Non-Sensitive
**To receive a copy of this document, indicate in the concurrence box "C" = Copy without attach/encl "E" = Copy with attach/encl "N" = No copy**

| OFFICE | RIII | | RIII | | RIII | | RIII | |
|---|---|---|---|---|---|---|---|---|
| NAME | RKWalton:bl | | MBielby for HPeterson | | | | | |
| DATE | 12/17/13 | | 12/17/13 | | | | | |

***OFFICIAL RECORD COPY***