NEXTera ENERGY SEABROOK

July 16, 2009

Docket 50-443
SBK-L-09161

United States Nuclear Regulatory Commission
Attn: Mr. Peter Presby, Operations Engineer/Chief Examiner
Region I
475 Allendale Road
King of Prussia, PA 19406-1415

Seabrook Station
<u>Request for Modification or Deletion of Examination Questions</u>

Reference: Letter SBK-L-09148, Gene St. Pierre to Peter Presby, dated June 26, 2009.

In the referenced letter, NextEra Energy Seabrook, LLC requested modification or deletion of examination questions pursuant to ES-501 of NUREG 1021. Subsequently, you requested additional information to support this re-grade request. This information was provided to you informally via e-mail correspondence. In a telephone conversation on July 14th you requested that Seabrook combine this additional information with that provided in the original submittal and re-submit as a revised document. Enclosure 1 to this correspondence contains the revised submittal and supersedes the information provided in the original submittal dated June 26, 2009.

Should you have any questions regarding this matter, please contact Mr. Kerry Wright, Nuclear Training Manager, at (603) 773-7627.

Very truly yours,

NextEra Energy Seabrook, LLC

Gene St. Pierre
Vice President North

NextEra Energy Seabrook, LLC, P.O. Box 300, Lafayette Road, Seabrook, NH 03874

cc:

Document Control Desk
S. J. Collins, NRC Region I Administrator
S. Hansell, Jr., NRC Region I Chief
D. L. Egan, NRC Project Manager, Project Directorate I-2
W. J. Raymond, NRC Senior Resident Inspector

In accordance with the guidance provided in NUREG 1021, "Operating Licensing Examination Standards for Power Reactors" (Revision 9 Supp 1), ES-403 "Grading Initial Site-Specific Written Examinations" justification for modification to the original examination answer key to accept two responses or to eliminate the question is provided in the following attachments.

The requested changes are:

Exam Question Number	Change to Answer Key
RO 25	Delete question
RO 43	Delete question
SRO 82	Accept A and D
SRO 83	Accept A and D
SRO 100	Delete question

Seabrook Station is performing a Root Cause analysis to determine the cause of the examination results. It appears inadequate technical reviews were a factor in the issues identified with the questions listed above. Seabrook Station is adopting a newly developed fleet standard exam development procedure. This procedure will be updated based on the lessons learned from the Root Cause analysis. This issue has been captured in the site corrective action program under Condition Report 00199879.

This document is a revision to the first regrade request of 6/26/09. Additional information for consideration during the regrade has been added to questions 25, 82, 83 and 100. The additional information has been incorporated into the complete document at the request of the NRC. This new submittal supersedes the original regrade request.

Facility Exam Author: Patrick Leary / 7-14-09
Printed Name and Signature / Date

Facility Representative: Kerry Wright / 7-14-09
Printed Name and Signature / Date

Question 25:

The following plant conditions exist:

- The plant has experienced a small break LOCA.
- Total EFW flow has been throttled to 550 GPM based on RCS temperature less than 557 degrees.
- The Crew has transitioned from E-0, "Reactor Trip or Safety Injection" to E-1, "Loss of Reactor or Secondary Coolant" and now to ES-1.1, "SI Termination" in order to reduce ECCS flow.
- Plant parameters are as follows:
  - Containment pressure is 1.5 psig and slowly decreasing.
  - Pressurizer level is 40% and increasing.
  - RCS Subcooling is 43° and stable.
  - RCS pressure is 1950 psig and stable.
- The crew is terminating SI.
- After placing the first CCP in standby, RCS pressure starts to slowly decrease.

Which of the following describes the correct procedural response to these conditions?

A. Restart the CCP and go to E-0, "Reactor Trip or Safety Injection".

B. Transition to ES-1.2, "Post LOCA Cooldown and Depressurization".

C. Restore normal charging path and control charging flow to maintain Pressurizer Level.

D. Initiate Safety Injection and transition to E-1, "Loss of Reactor or Secondary Coolant".

Answer: B

Initial Regrade request Comment:

ES-403 D.1.c Re-grade criteria: Two answers are determined to be correct, however both answers contain conflicting information, accordingly this question should be deleted.

The first Charging pump is secured in ES-1.1, "SI Termination", step 2. Step 3 checks RCS pressure "STABLE or INCREASING...". If RCS pressure is determined to be "STABLE" then normal charging is restored using step 4. When the first Charging pump is secured RCS pressure will initially decrease. If the remaining ECCS flow provides adequate inventory makeup then the RCS will stabilize at a lower pressure and an attempt is made to realign the normal charging flowpath. If the remaining ECCS flow does NOT supply enough inventory then RCS pressure will continue to decrease and a transition is made to ES-1.2, "Post LOCA Cooldown and Depressurization". No information concerning the duration of the "slow pressure drop" was provided in the question. Both answer "B" and "C" are correct depending on the assumed time frame of the plant conditions.

During the exam administration a candidate (docket number 055-63183) asked: "Over what time frame is the last bulleted item ("After placing the first CCP in standby, RCS Pressure starts to slowly decrease") assumed to occur? Is this the expected initial pressure drop when the first CCP is stopped, or is this slow pressure decrease continuing?"

The student question was discussed with the Chief Examiner via phone during the exam. The exam writer and the Chief Examiner explored adding some additional pressure trends to the question, but decided to NOT add any clarifying information because ~ ½ of the candidates had already finished the exam and left the room.

Recommendation: Delete question.

(continued next page)

Technical Reference(s):

ES-1.1 "SI TERMINATION", steps 1, and 2.

Number	Title	Rev./Date
ES-1.1	SI TERMINATION	34 06/18/08

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
CAUTION	• *If offsite power is lost after SI reset, manual action may be required to restart safeguards equipment.* • *If the master pressurizer pressure controller output becomes saturated, manual action may be required to control pressure.*	
NOTE	• *If a LOP has occurred, verify service water cooling to the diesel generator.* • *Review OPERATOR ACTION SUMMARY periodically.*	
1	**Reset SI**	
2	**Stop All But One CCP And Place In Standby**	
3	**Check RCS Pressure - STABLE OR INCREASING BY PRESSURE RECORDER**	Go to ES-1.2, POST LOCA COOLDOWN AND DEPRESSURIZATION, Step 1.
4	**Restore Normal Charging Path:**	
	• OPEN CS-V142	
	• OPEN CS-V143	
5	**Establish Normal Charging Flow:**	
	a. Isolate CCP to RCS cold legs:	
	• CLOSE SI-V138	
	• CLOSE SI-V139	
	b. Establish 60 GPM charging flow using CS-FCV-121	
	c. Adjust seal injection flow for 6 GPM to 10 GPM using CS-HCV-182	

2 of 30

Additional regrade request comments for question 25:

Question 25 concerned the expected plant response and correct procedural guidance during SI flow reduction during a small break LOCA. The conditions stated established initial Reactor Coolant conditions as follows:

The given conditions as:

- o Pressurizer level is 40% and increasing.
- o RCS Subcooling is 43° and stable.
- o RCS pressure is 1950 psig and stable.

The assumed condition of:

- o All ECCS equipment in service

The question concerns the decision point after the recovery procedure has placed the first High Head Centrifugal Charging Pump to standby. RCS pressure response to this action was stated as: "starts to slowly decrease". The original regrade request submitted that two answers were correct, but the answers were mutually exclusive, so the question should be deleted from the exam.

The original answer for the question was:

B. Transition to ES-1.2, "Post LOCA Cooldown and Depressurization".

This answer is based on ES-1.1, "SI termination", step 3. This step checks that RCS pressure is stable or increasing after stopping the CS pump and, if not, directs a transition to ES-1.2. This answer is the correct flowpath for "smart" leak sizes that are smaller than the combined capacity of 2 CS pumps running in the ECCS injection mode, but larger than the capacity of 1 CS pump running in that same mode.

The regrade request asserted that under other plausible conditions answer "C" was also correct. This answer stated the correct response for the conditions given were to:

C. Restore normal charging path and control charging flow to maintain Pressurizer Level.

This answer would be correct if an applicant assumed that the RCS pressure response ("starts to slowly decrease") after the first CS pump was secured was the expected plant response to securing the first CS pump, and that RCS pressure would stabilize at a new equilibrium pressure below the starting point. The Seabrook SI flow reduction methodology uses a "stepped" method of flow reduction. In this method the high head injection ECCS pumps are secured one at a time and plan response is evaluated. As each pump is secured there is a stepped decrease in RCS pressure but, provided that sufficient makeup inventory was still provided, the RCS pressure should stabilize and the next step in flow reduction is attempted. For Seabrook the optimal reduction scheme is as follows:

- Both High head injection pumps (CS pumps) are initially running in the ECCS injection line up.

- The First High Head injection pump is secured.
- RCS pressure should decrease, then stabilize at a new equilibrium.
- If RCS pressure does not stabilize then transition to ES-1.2, "Post LOCA Cooldown and Depressurization."
- If RCS pressure stabilizes then the normal charging flowpath is established for the remaining High Head injection pump (the new flowpath is aligned in parallel with the High Head ECCS injection flowpath).
- The High head ECCS injection flowpath is secured, leaving just the normal charging flowpath. RCS pressure should decrease, then stabilize at a new equilibrium pressure.
- If RCS pressure does not stabilize then transition to ES-1.2, "Post LOCA Cooldown and Depressurization."

During the exam administration a candidate asked:

"Over what time frame is the last bulleted item ("After placing the first CCP in standby, RCS Pressure starts to slowly decrease") assumed to occur? Is this the expected initial pressure drop when the first CCP is stopped, or is this slow pressure decrease continuing?"

The student question was discussed with the Chief Examiner via phone during the exam. The exam writer and the Chief Examiner explored adding some additional pressure trends to the question, but decided to NOT add any clarifying information because ~ ½ of the candidates had already finished the exam and left the room. Although additional information seemed merited, it would cause an unfair advantage for the students still remaining in the room. Appendix "E" of NUREG 1021, part B, item 7, 1st paragraph states:

> "If you have any questions concerning the intent or the initial conditions of a question, do *not* hesitate to ask them before answering the question. Note that questions asked during the examination are taken into consideration during the grading process and when reviewing applicant appeals."

The question asked by the student appears to be directly germane to the crux of the question: is the pressure drop the EXPECTED, initial drop in RCS pressure while new equilibrium conditions are established or does this pressure drop continue past that point? The two answers determined to be correct state the proper response to these two choices.

Conclusion:

The facility feels that information concerning the size and duration of the RCS pressure drop was lacking in the question as given. Both answers B and C are correct answers based on reasonable assumptions drawn from the limited information provided to the students.

The question should be deleted based on conflicting answers.

NRC Resolution:

Question 43:

Given the following plant conditions:

- The reactor is operating at full power near end of life.
- A Large Feedwater Line break downstream of the Feed Line check valves inside containment occurs.

Which of the following parameter trends would initially distinguish the Large Feedwater Line break from a Large Main Steam Line break inside containment?

A. Reactor Power prior to the reactor trip.

B. Containment pressure after the reactor trip.

C. Affected Steam generator pressure after the reactor trip.

D. Affected Steam Generator narrow range level after the reactor trip.

Answer: A

Comment:

ES-403 D.1.b Re-grade criteria; newly discovered technical information that contradicts the answer key. Based on Seabrook Simulator response (See attached data) original answer is not correct. There is no correct answer.

The original explanation for answer "A" postulated that Reactor Power should initially increase for a steam line break due to the positive reactivity added as Tavg drops with the increased steam demand. For a feed line break Reactor Power will remain the same initially, then start to decrease as SG inventory is depleted and less heat is removed from RCS and Tavg begins to rise. These conclusions were based largely on the information presented in the Westinghouse owners group background document for E-2, "Faulted Steam Generator Isolation".

Simulator data concludes that for both a large feed line break and a large steam break (with break flows peak at ~8,000 lbm/sec – to match UFSAR case studies) a safety injection and reactor trip on containment pressure > 4.3 psig occur almost instantaneously after the initiation of the break, so the hypothetical changes in reactor power are not seen. The attached trends provide break flow, NI indicated power, containment pressure response, and the simulator instantaneous core power. Note that the current simulator modeling of containment response is based on a Westinghouse simulator analysis performed as part of the plant power up-rate done in 2007. This model uses plant "best case" expected response to provide the most realistic model of containment performance to the students.

The discussion section of E-2 bounds intermediate size breaks as between those that could be handled by normal plant controls to those that do not generate any protective actions until greater than 5 minutes from break initiation. The discussion on large breaks is only focused on double-ended breaks. The background document does not contain a graph of the expected response of core power during a large feed break: just RCS pressure response, Pressurizer level response, RCS loop temperature response, and SG pressure response. The background document does not provide any graphs of expected plant response during a large steam break. The discussion section of E-2 does discuss that either type of large break inside containment would cause changing containment pressure and temperature but does not discuss the magnitude or expected plant protective actions of those changes. The original answer "A" was based on exam writer extrapolation of the expected response of core power based on that provided information.

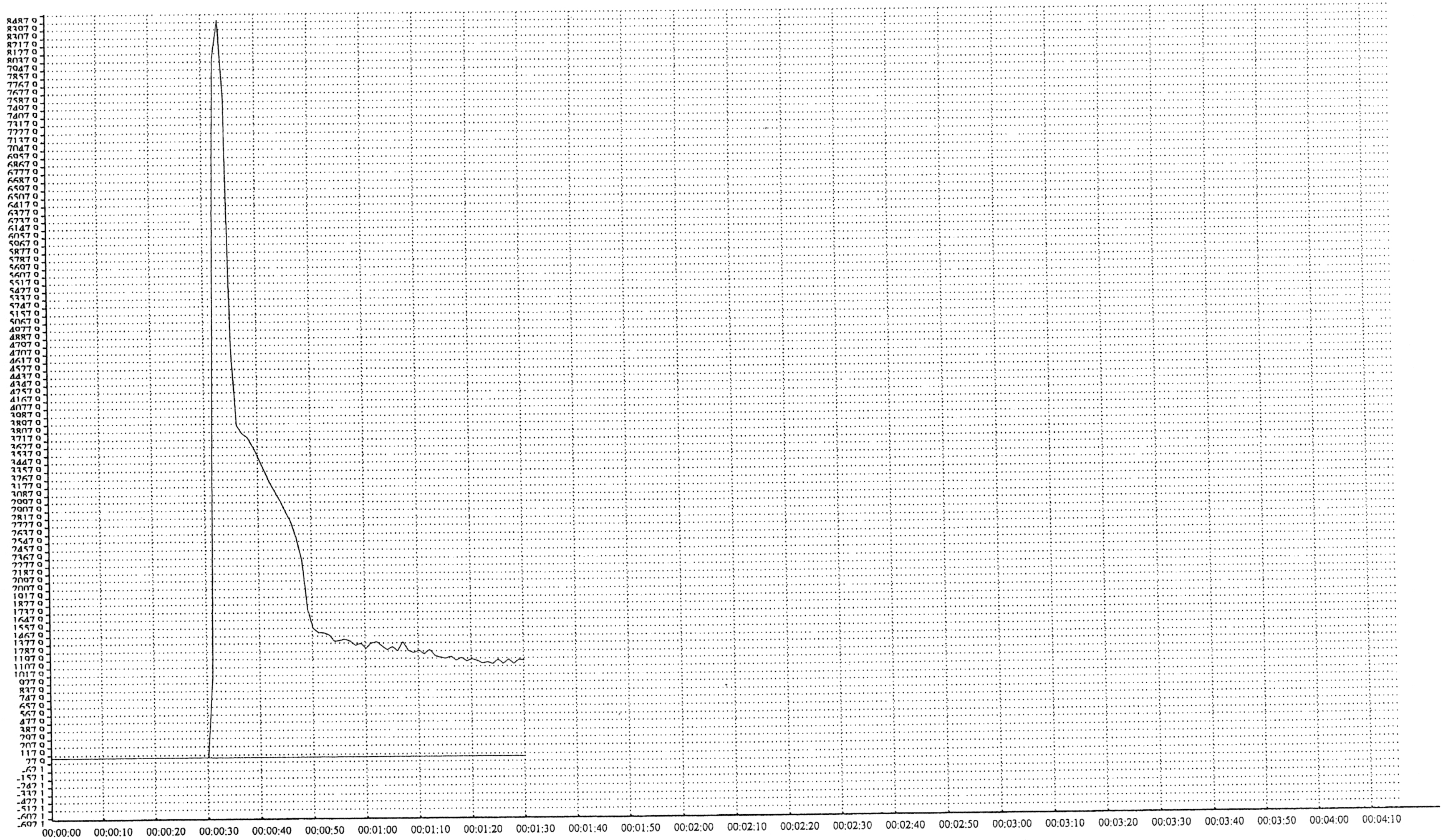
The UFSAR was reviewed to ensure no contradictory information to the conclusion that containment pressure rapidly increases above the Safety Injection actuation pressure of 4.3 psig. Containment response to accident conditions is discussed in the UFSAR in section 6.2, Containment Systems, and chapter 15, Accident Analysis. In section 6.2 Feed line breaks are bounded by the more limiting steam line breaks (UFSAR 6.2.1.4, page 37). Analysis information for the large steam line breaks assumes a full double-ended rupture, with additional discussion of small double ended ruptures which are large enough to generate a Main Steam Line Isolation signal because they present the most limiting conditions of containment temperature rise. This analysis was performed using the worst case failure criteria, in this case either the broken loop Main Steam Isolation valve fails to close, or one train of CBS fails to actuate. The attached table 6.2.-69 shows that for these worse case failures that break flow peaks at ~ 8600 lbm/sec, then decreases as SG pressure decreases. The attached tables 6.2-20 and 6.2-22 shows that containment pressure reaches 10 psig almost instantaneously at the onset of the failure. This does not contradict the trends obtained from simulator performance. UFSAR section 15.1.5 discusses Steam System Piping failures. The focus of this discussion is the possible return to power operation based on the excessive RCS cooldown. This accident analysis credits a safety injection signal actuated from Containment pressure reaching 4.3 psig (Section 15.1, page 11). The discussion is focused on the more limiting plant conditions of hot, zero power which is different that the initial conditions of the question of 100% power. No tables or figures are provided for this section that characterize the expected containment pressure response. Section 15.2.8 discusses a Feedwater System Pipe Break. This discussion does state that a containment high pressure safety injection would provide protection for main feedwater piping system failure, but the affects on containment pressure are not discussed because the main steam line rupture in containment is a more limiting accident condition. No tables or figures are provided for this section which characterize the expected containment pressure response

Conclusion: None of the choices presented to the students created clearly distinct trends that could be used by an operator to differentiate between a Large Feed line Break and a Large Steam Line Break.

Recommendation: Delete this question.

Technical Reference(s):
Attached Simulator performance curves, UFSAR section 6.2, Containment systems, and Chapter 15, accident analysis

Steam Line Break Flow



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msf001(13) 0.000 MASS FLOW RATE IN LINK#1

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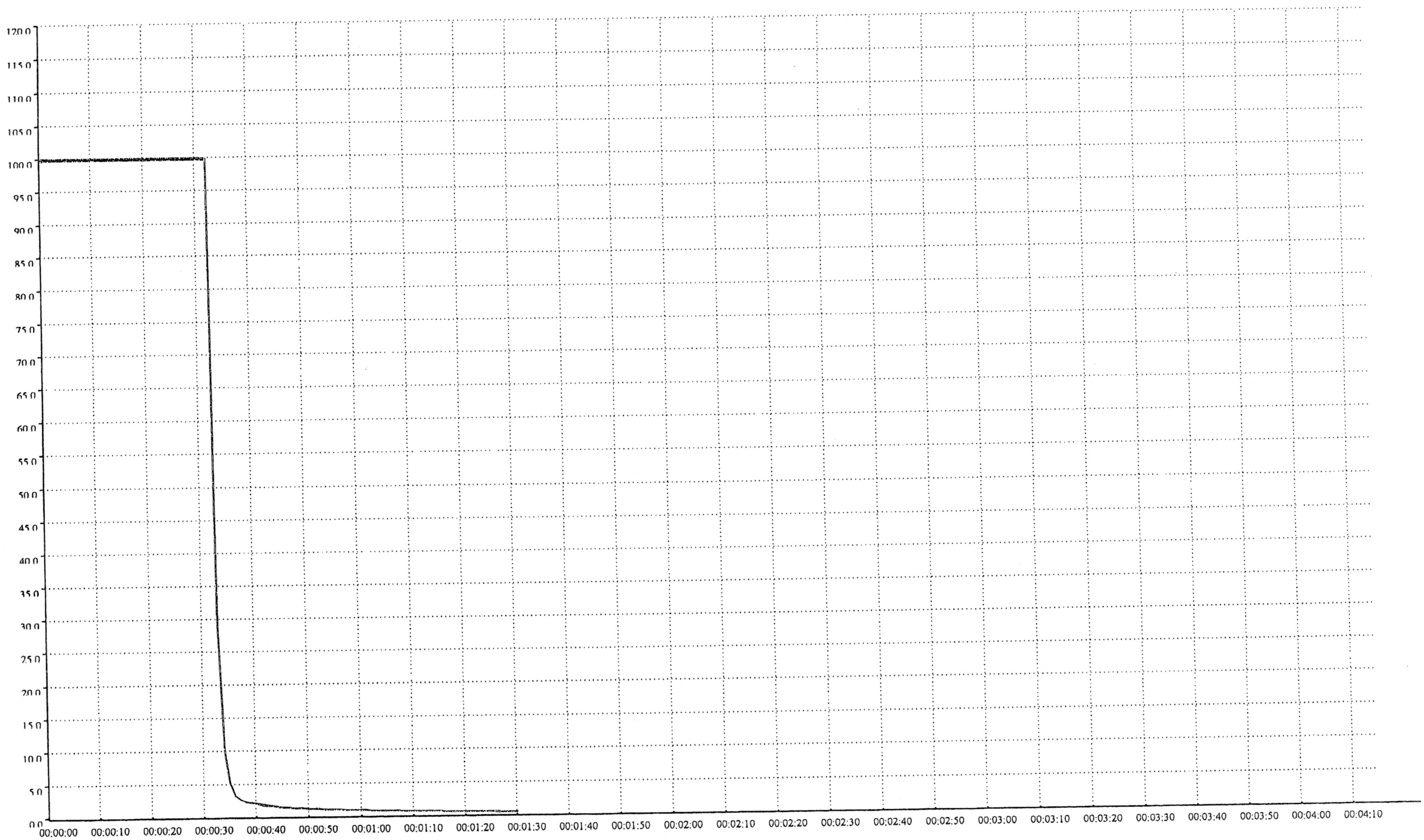
LSH NIs



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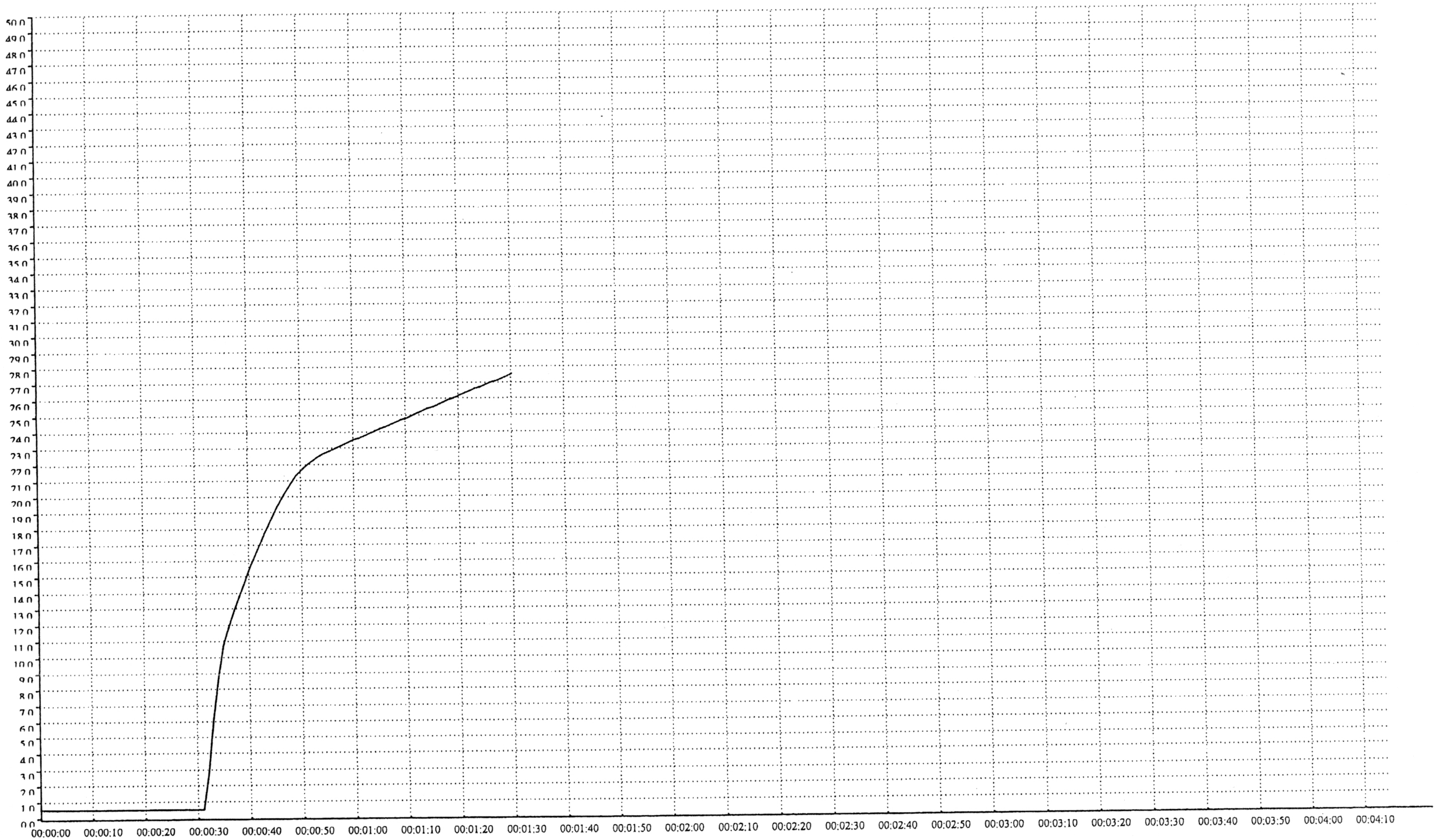

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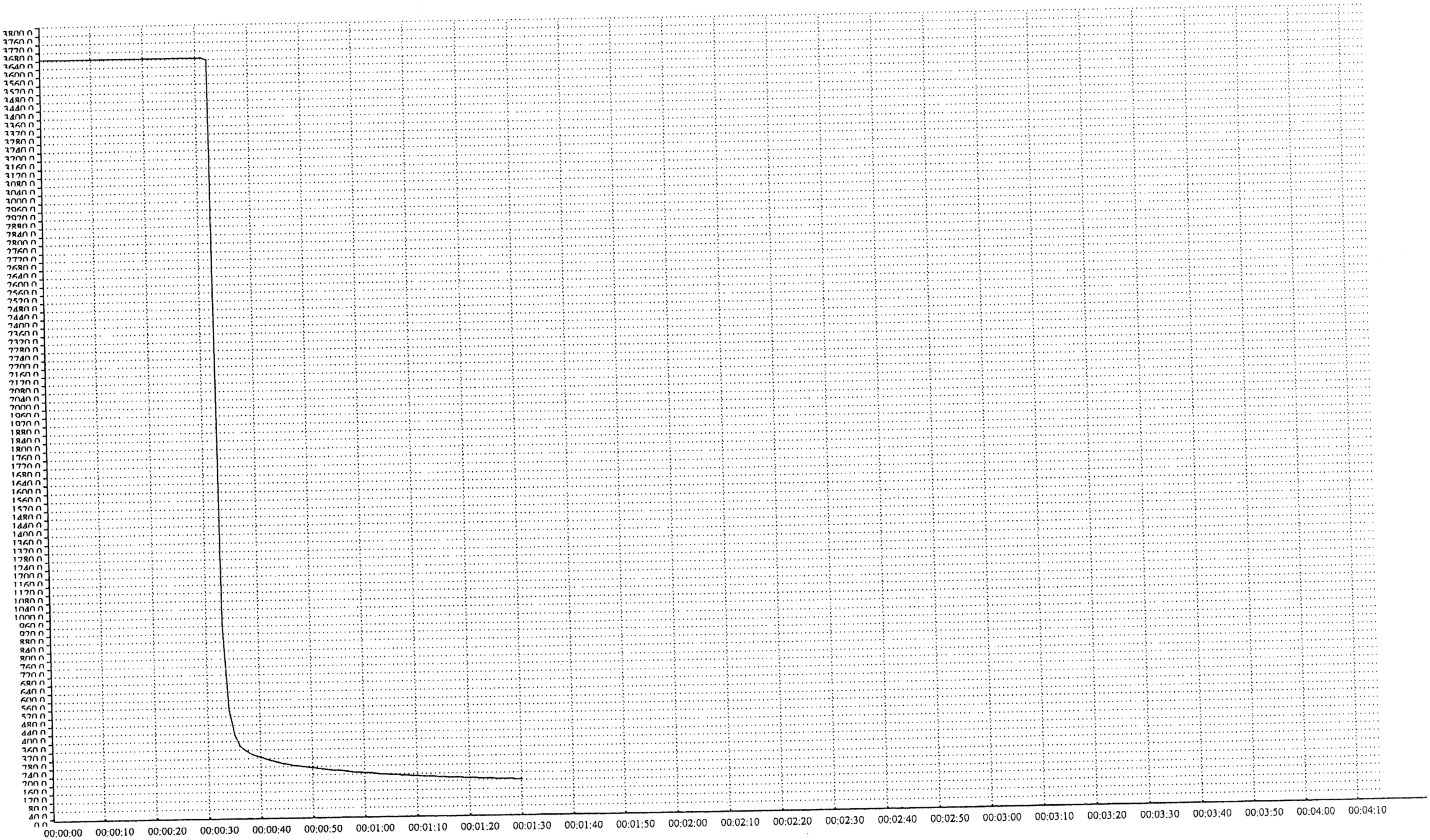
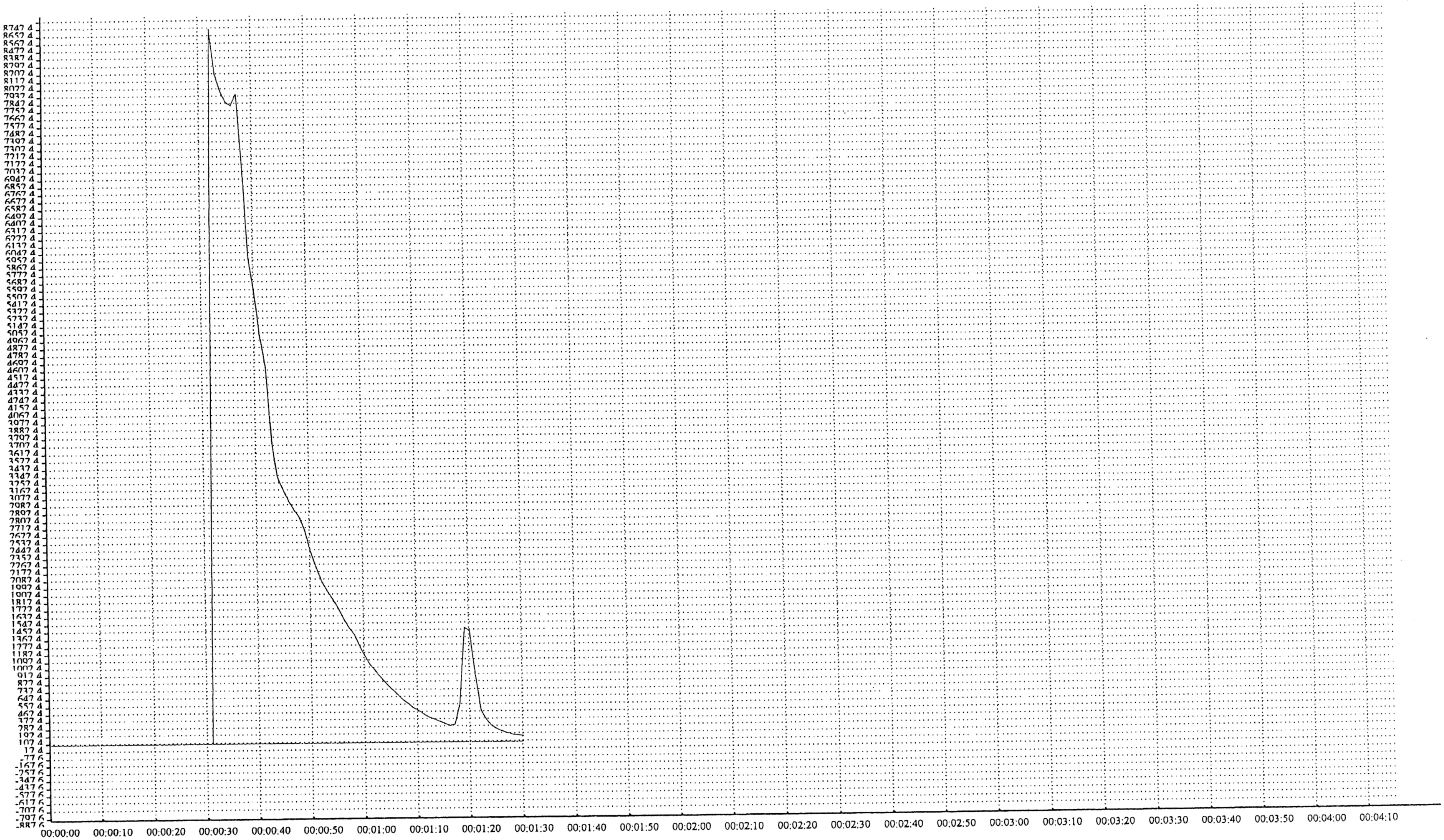


crqmwt 164.807 INSTANTANEOUS MEGAWATT

Feed Line Break Flow



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fwf001(88) 0.000 FLOW IN LINK #1

fwf001(90) 0.000 FLOW IN LINK #1

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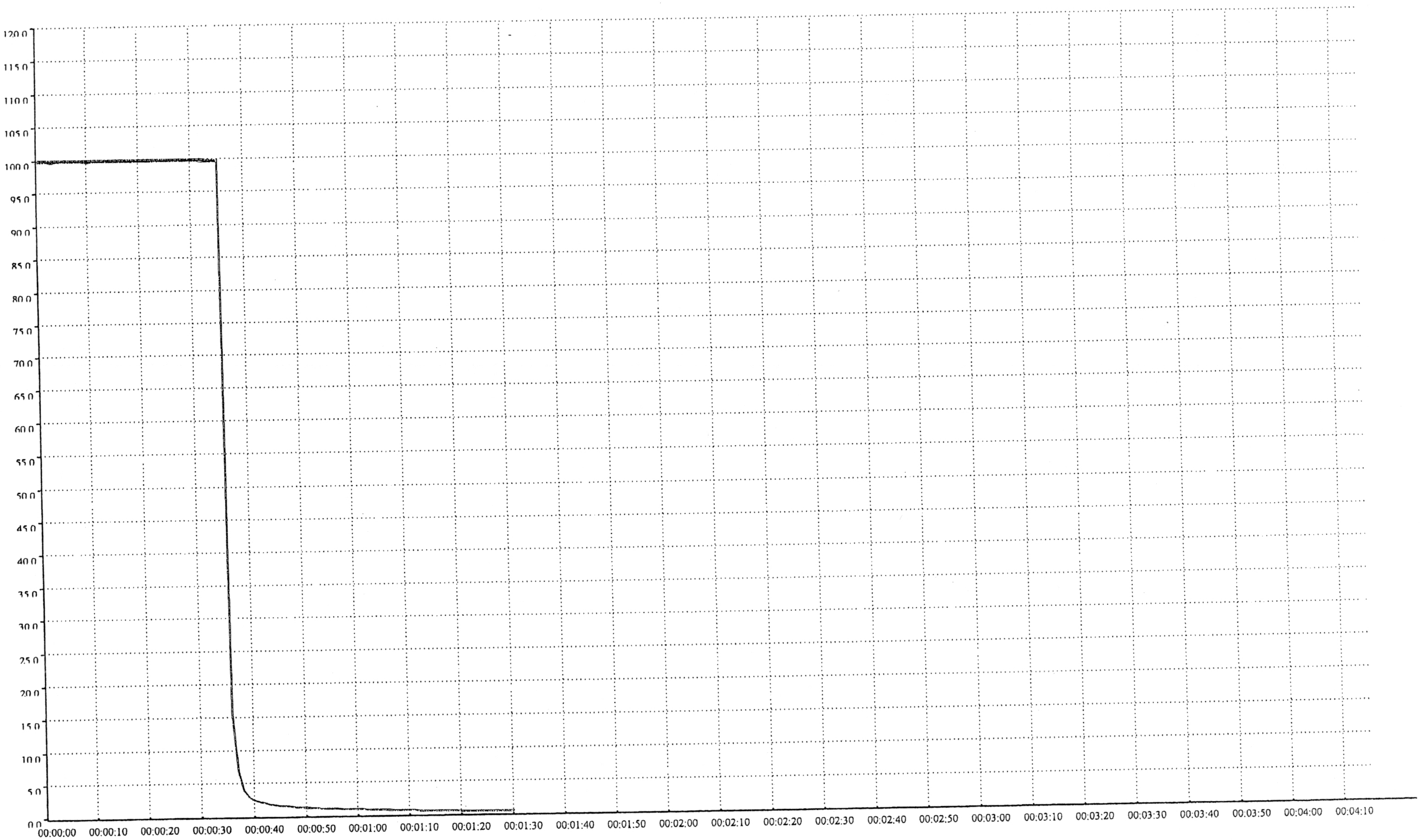
LSH NIs



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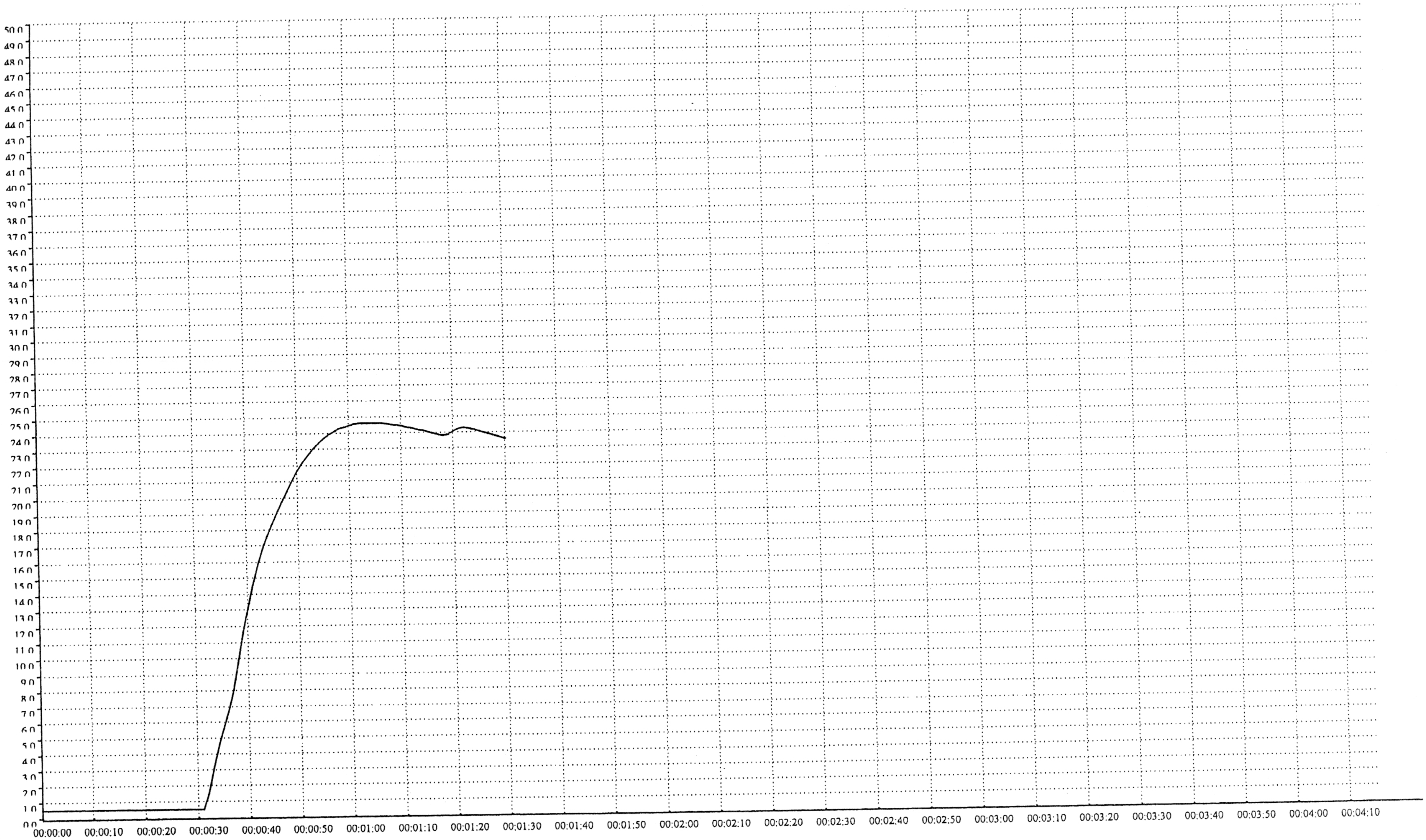

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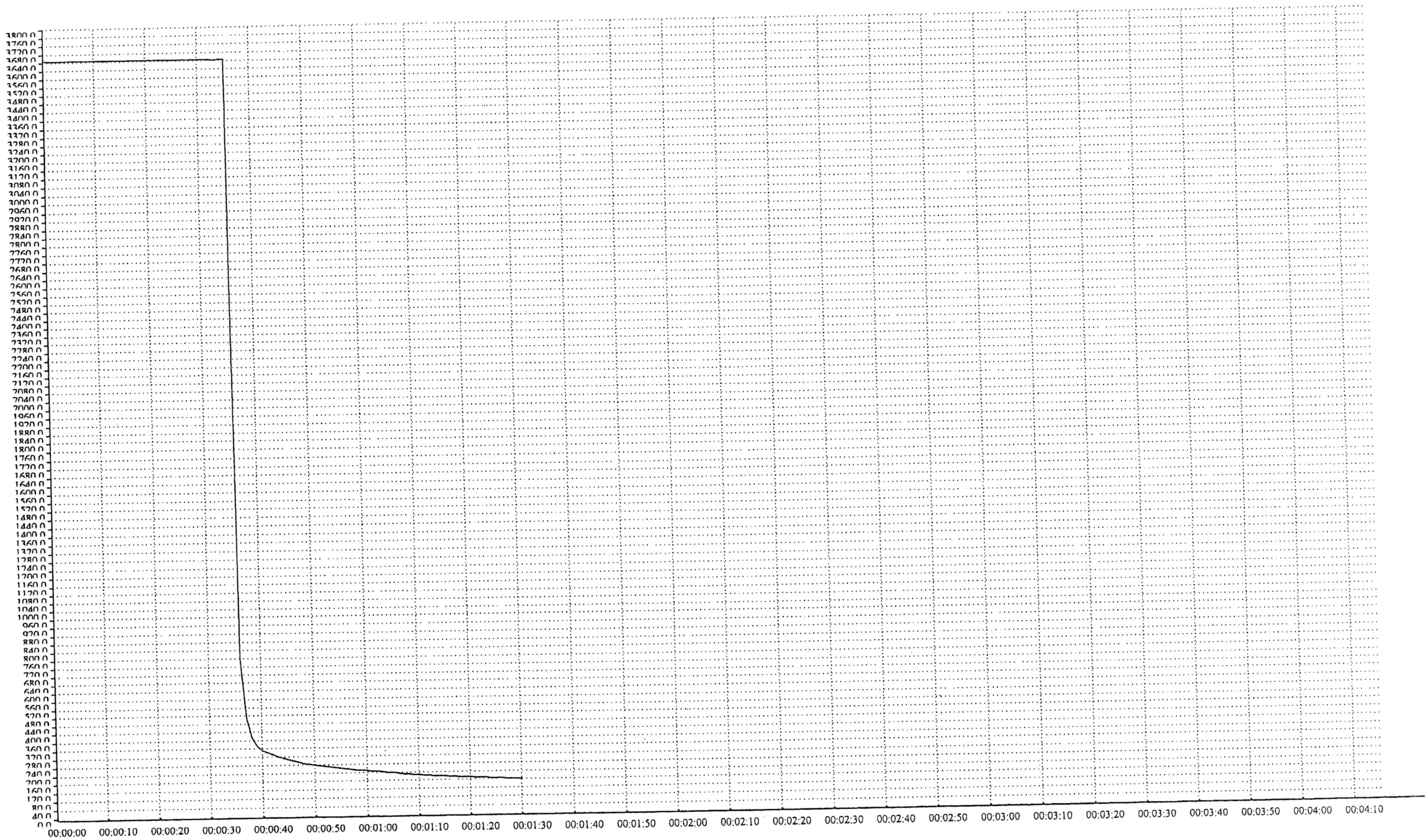

crqmwt 162.700 INSTANTANEOUS MEGAWATT

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SEABROOK STATION UFSAR	ENGINEERED SAFETY FEATURES Containment Systems	Revision 12 Section 6.2 Page 37

6.2.1.4 **Mass and Energy Release Analysis for Postulated Secondary System Pipe Ruptures inside Containment**

a. Mass and Energy Release Data

The mass and energy releases into the containment following a postulated main steam line break (MSLB) have been calculated by using the model described in Subsection 6.2.1.4d and incorporating the balance-of-plant parameters for Seabrook Station via the procedure described in Reference 15.

The effects of a postulated feedwater line rupture are not as severe as the main steam line break because the break effluent of a feedwater line rupture is at a lower specific enthalpy. Therefore, feedwater line break mass and energy releases to the containment are not addressed here since they are bounded by steam line break releases.

1. Break Type/Size and Operating Power

The plant operating power levels at the time of the MSLB and the spectrum of break types and sizes analyzed have been presented in Table 6.2-10 and Table 6.2-11 respectively. Full double-ended rupture (DER) area is determined by the integral flow restrictor area. This break represents the largest possible break. A small double-ended rupture has been considered for each power level. These break sizes have been chosen to be large enough to generate a steam line isolation signal from the Primary Protection System. For any ruptures smaller than these small double-ended ruptures, an isolation signal is generated by containment pressure. Two such cases have been analyzed with approximately half the corresponding size of the small double-ended rupture. These breaks are expected to cover adequately the full spectrum of double-ended break sizes. For the split ruptures, the break sizes selected are the largest sizes which will not generate a steam line isolation signal from the Primary Protection System. An isolation signal is generated on containment pressure. Larger split ruptures will generate primary protection signals and are expected to be bounded by the double-ended ruptures. The breaks are assumed to be at the exit of a steam generator flow restrictor for double-ended ruptures, and at any point on the piping between a steam generator and the first main steam pipe whip restraint inside the containment for split ruptures.

SEABROOK STATION UFSAR	ENGINEERED SAFETY FEATURES TABLE 6.2-69	Revision: 10 Sheet: 1 of 1

TABLE 6.2-69 FULL DOUBLE-ENDED MSLB AT 102% POWER (WITH SAF OF BROKEN LOOP MSIV) MASS AND ENERGY RELEASES (REVERSE FLOW)

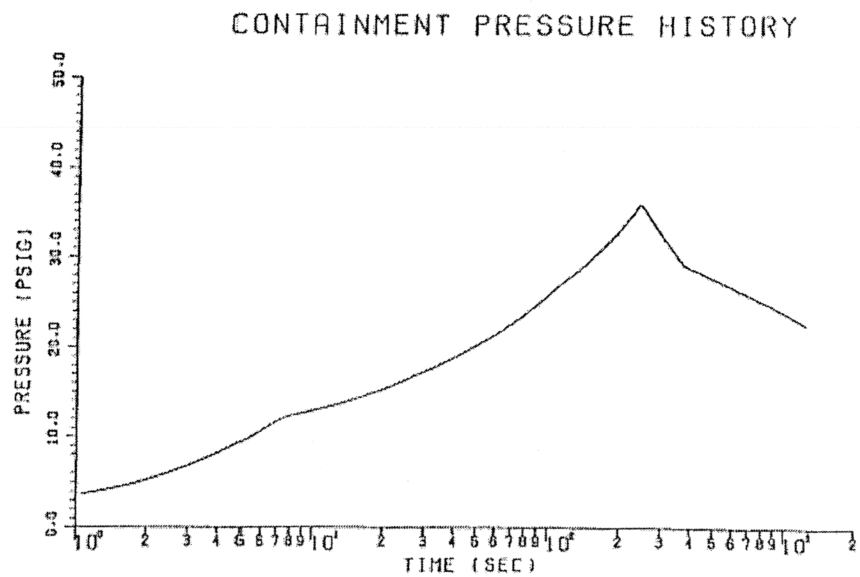
Time (sec)	Mass Flow (lbm/sec)	Enthalpy (Btu/lbm)
0.0	8611	1193.2
0.250	8611	1193.4
0.251	4058	1193.5
1.0	3944	1195.1
2.0	3813	1196.5
3.0	3711	1197.6
4.0	3630	1198.3
5.0	3562	1198.8
6.0	3505	1199.1
6.5	3479	1199.3
7.0	3335	1199.4
8.0	3098	1199.5
9.0	2760	1199.8
10.0	2473	1200.0
11.0	2185	1200.2
12.0	1898	1200.5
13.0	1610	1200.8
14.0	1323	1201.2
15.0	1035	1201.6
16.0	748	1202.2
17.0	460	1202.9
18.0	173	1203.8
18.6	0	1204.5
∞	0	1204.5

Note: This table presents mass and energy release data related to the MSLB containment response analysis of record. Section 6.2.1.8 contains a discussion of the mass and energy release data associated with this analysis of record, as compared with the mass and energy release data associated with the MSLB containment response at an analyzed core power level of 3659 MWt.

SEABROOK STATION
UPDATED FINAL SAFETY
ANALYSIS REPORT

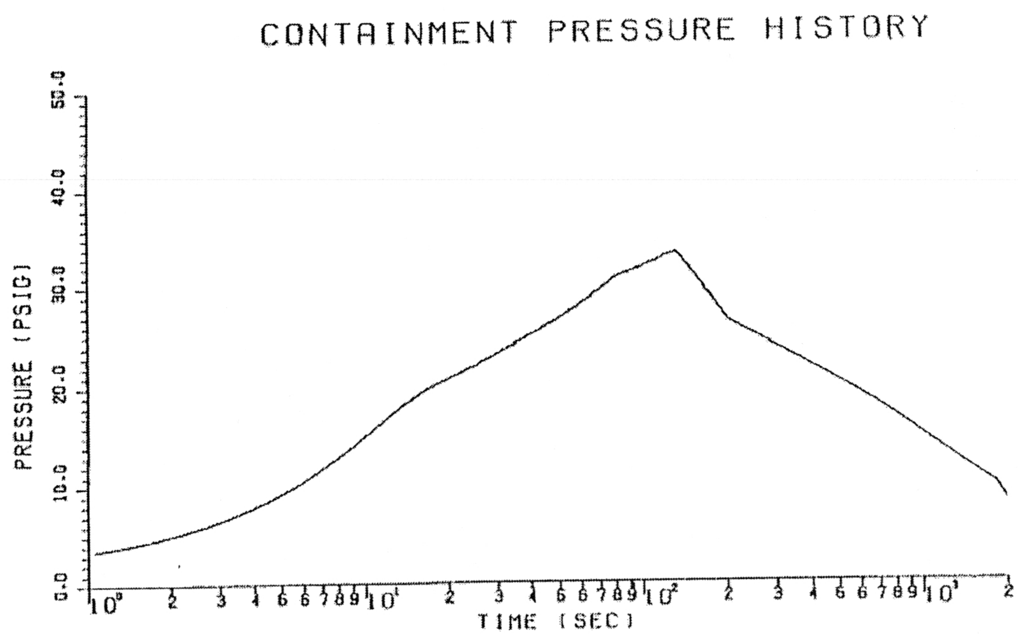
Containment Response Following Full DE Main Steam Line Break at Hot Shutdown with One Spray Train Failure

Figure 6.2-20



Note: This figure presents results related to the MSLB containment response analysis of record. Section 6.2.1.8 contains a discussion of the results of this analysis of record, as compared with the MSLB containment response results at an analyzed core power level of 3659 MWt.

SEABROOK STATION UPDATED FINAL SAFETY ANALYSIS REPORT	Containment Pressure Response Following Full DE Main Steam Line Break at 102% Power with Broken-Loop MSIV Failed
	Figure 6.2-22



Note: This figure presents results related to the MSLB containment response analysis of record. Section 6.2.1.8 contains a discussion of the results of this analysis of record, as compared with the MSLB containment response results at an analyzed core power level of 3659 MWt.

SEABROOK STATION UFSAR	ACCIDENT ANALYSES Increase in Heat Removal by the Secondary System	Revision 12 Section 15.1 Page 10

The limiting steam line break presented in this section corresponds to a double-ended rupture of the main steam line at the steam generator nozzle at zero power with offsite power available.

The analysis of a main steam line rupture is performed to demonstrate that the following criteria are satisfied:

a. Assuming a stuck RCCA with or without offsite power, and assuming a single failure in the Engineered Safety Features, the core remains in place and intact. Radiation doses do not exceed the guidelines of 10 CFR 100.

b. Although DNB and possible clad perforation following a steam pipe rupture are not necessarily unacceptable, the following analysis, in fact, shows that no DNB occurs for any rupture assuming the most reactive assembly stuck in its fully withdrawn position.

A major steam line rupture is classified as an ANS Condition IV event. A minor steam line rupture is classified as an ANS Condition III event.

Effects of minor secondary system pipe breaks are bounded by the analysis presented in this section. Minor secondary system pipe breaks are classified as Condition III events.

The major rupture of a steam line is the most limiting cooldown transient and is analyzed at zero power with no decay heat. Decay heat would retard the cooldown thereby reducing the return to power. A detailed analysis of this transient with the most limiting break size, a double-ended rupture, is presented here.

The following functions provide the protection for a steam line rupture:

a. Safety injection system actuation from any of the following:

   1. Two out of four low pressurizer pressure signals

   2. Two out of three high-1 containment pressure signals

   3. Two out of three low steam line pressure signals in any one loop.

b. The overpower reactor trips (neutron flux and ΔT) and the reactor trip occurring in conjunction with receipt of the safety injection signal.

c. Redundant isolation of the main feedwater lines. Sustained high feedwater flow would cause additional cooldown. Therefore, in addition to the normal control action which will close the main feedwater valves, a safety injection signal will rapidly close all feedwater isolation valves and backup feedwater control valves and trip the main feedwater pumps.

d. Trip of the fast-acting Main Steam Isolation Valves (MSIVs) which are designed to close in less than 5 seconds after receipt of a signal on:

   1. High-2 containment pressure

NRC Resolution:

QUESTION 82:

The following conditions exist:

- The plant is at 100% power.
- Two Control Rods drop into the core.
- The crew has entered OS1210.05, "Dropped Rod'.

Why does OS1210.05, "Dropped Rod', direct a manual Reactor Trip if more than one control rod has been dropped?

A. Unanalyzed Rod configurations invalidates the assumed rod worth used in the safety analyses.

B. Multiple rod drops will cause the heat flux hot channel factor to exceed the design limits on peak local power density.

C. The value of predicted Moderator Temperature Coefficient CANNOT be assured to remain within the limiting condition assumed in the FSAR accident and transient analysis.

D. Multiple rod drops or partial rod drops beyond those limited variations that allow continued power operation in Technical Specifications may produce power distributions outside of design limits.

Answer: D

Initial regrade request comments :

ES-403 D.1.c Re-grade criteria; newly discovered technical information shows that two answers are correct. Answer "A" is also a correct answer as explained below.

Answer A has been identified as correct: When a rod or rods drops into the core the neutron flux profile will be suppressed in those areas, but increase in the rest of the core. This increase in flux level in the rest of the core will change the rod worth of control rods in those regions. This conclusion is discussed in detail in the included technical reference material.

Original answer D is correct. The TS bases for 3.1.3, Movable Control Assemblies, states in the second paragraph that "ACTION statements which permit limited variations from the basis requirements are accompanied by additional restrictions which ensure the original design criteria are met... ..In addition, those safety analyses affected by a misaligned rod are reevaluated to confirm that the results remain valid during future operation." The station specific AOP for dropped rods has determined that operating outside those limited variations that allow continued power operation in Technical Specifications may produce power distributions outside of design limits. The Dropped

Rod procedure conservatively trips the plant when it has been determined that multiple dropped rods has occurred because the required safety analysis may not support continued operation and the evaluation could not reasonably be expected to be performed within the 1 hr TS limit to recover the rods.

Recommendation: Accept two answers, A and D.

Technical Reference(s)
GFES Lesson L8125I, "Control Rods", pages 27, 28, and 29. This lesson specifically states:

Individual control rod worth is affected by presence of other control rods in reactor

- The insertion of control rod changes shape of neutron flux in reactor, as shown in Figure 5-15a
- As one can observe from this figure, thermal neutron flux drops sharply as one of individual absorber rods of rodded control rod assembly enters into flux
- A similar phenomenon will also occur if overall assembly enters as well

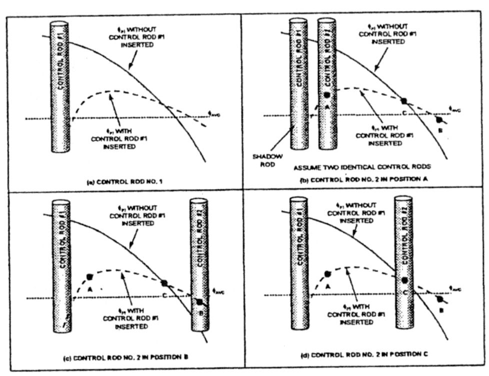
Inserting one control rod would result in significant power reduction in upper region of core, as shown by control rod No. 1 in Figure 5-15a

If control rod No. 2 is inserted at position A (Figure 5-15b), reactivity worth of rod No. 2 is lower with rod No. 1 inserted (compared to flux without rod No. 1)

- This is because neutron flux is depressed

Therefore, it can be said that rod shadowing is process in which movement of control rod results in neutron flux increase or decrease in vicinity of one or more other control rods in core, resulting in change in worth of affected rods

Figure 5-15 / TP 5-32 through TP 35



Or, stated another away, if adjacent rod is inserted, its worth is reduced because of lower local flux The power reduction caused by inserting second rod is less than power reduction caused by inserting first rod The second rod is said to be shadowed by first rod Generally, one rod shadows another if it is within one neutron thermal diffusion length Shadowing can increase or decrease worth of adjacent rod depending on existing core conditions: specifically, ratio of local to average flux Therefore, one could say that control rod No. 2 has been "shadowed" due to presence of control rod No. 1 This sometimes is referred to as *positive shadowing* effect where worth of rod No. 2 has dropped (Positive implies [+], and shadowing implies [-] Hence, product of [+] times [-] yields [-], thereby denoting drop in rod worth for rod No. 2.) However, if neutron flux is lowered in one region, flux must be raised in another region to maintain constant power level	

If after inserting control rod No. 1, control rod No. 2 is now placed in position B, rod No. 2 will have higher reactivity (compared to flux without rod No. 1 inserted), as illustrated in Figure 5-15c In this case, worth of rod No. 2 at position B is said to be *negatively shadowed* (Negative implies [-], and shadowing implies [-] Hence, product of [-] times [-] yields [+].) **Therefore, at position B, rod No. 2 worth would be higher** If control rod No. 2 is placed in position C (Figure 5-15d), control rod No. 2 would have same reactivity worth independently of whether control rod No. 1 is inserted or not inserted Hence, no rod shadowing has taken place We can state that when control rod is withdrawn, **worth of withdrawn control rod decreases** Core power also increases in area of rod tip due to exposure of fuel above control rod Because of increased thermal neutron flux at fuel, control rod worth in area of increased flux also increases	

Additional regrade request comments for question 82:

In the original requested regrade answer A has also been identified as correct: When a rod or rods drops into the core the neutron flux profile will be suppressed in those areas, but increase in the rest of the core. This increase in flux level in the rest of the core will change the rod worth of control rods in those regions. This conclusion was supported in detail in the previously included technical reference material, GFES lesson L8125I, "Control Rods".

NRC follow up request for information:

Provide further information supporting the phrase; "safety analysis".

Technical Specification 3.1.3.1, "Movable Control Assemblies", provides the operating limitations associated with Control Rod misalignment, as would be the case in a dropped rod or multiple dropped rods. Action b.3.a, provides a direct reference to the safety analysis that are related to Control Rod operability; Table 3.1-1. (included in attached reference material). This tie between Control Rod operability and accident analysis is also restated in the T.S. bases discussion for 3/4.1.3, but without referencing the Table by title. (see attached reference material). The accident analyses that require re-evaluation in the event of an inoperable full length rod are as follows:

- Rod Cluster Control Assembly Insertion Characteristics
- Rod Cluster Control Assembly Misalignment
- Loss of Reactor Coolant from Small Ruptured Pipes or from Cracks in
- Large Pipes Which Actuates the Emergency Core Cooling System
- Single Rod Cluster Control Assembly Withdrawal at Full Power
- Major Reactor Coolant System Pipe Ruptures (Loss-of-Coolant Accident)
- Major Secondary Coolant System Pipe Rupture
- Rupture of a Control Rod Drive Mechanism Housing (Rod Cluster Control Assembly Ejection)

These accident analyses are described in UFSAR chapter 15.

UFSAR section 15.4.3, "Rod Cluster Control Assembly Misoperation" provides the most direct discussion of the potential effects of multiple dropped rods. This section provides information on the following control rod misalignment combinations:

a. One or more dropped RCCAs within the same group

b. A dropped RCCA bank.

c. Statically misaligned RCCA

d. Withdrawal of a single RCCA.

NO specific analysis has been performed for multiple dropped rods in multiple core location, and that is the bases for tripping the plant if it is in that configuration in the first place. The analysis for the adverse affects of multiple rod drops within a group state that the more limiting condition is a "Dropped RCCA bank" so this becomes the bounding analysis. The discussion of the affects of the "Dropped Rod bank" hinges on a comparison of the worth of the dropped bank as compared to the worth of control bank D rods (which are assumed to withdraw in automatic). When rod worths change as a result of a neighboring dropped rod, as proven in the GFES Control Rod lesson, the assumed rod initial rod worths used to analyze those affects would be invalid.

Other UFSAR chapter 15 accident analyses affected by a changed assumed rod worth:

UFSAR section 15.4.1, "Uncontrolled Rod Cluster Assembly withdrawal from a Subcritical or Low power startup condition", 3rd paragraph, states that "The maximum (positive) reactivity insertion rate analyzed in the detailed plant analysis is that occurring with the "simultaneous withdrawal of the combination of two sequential control banks having the maximum combined worth at maximum speed". This same bounding parameter is also used in UFSAR section 15.4.2, "Uncontrolled Rod Cluster Assembly withdrawal at power", as stated in subsection 15.4.2.2, item 4 and 5. In these two accident conditions any condition that changes rod worths (i.e. multiple rods dropped) would differ from the assumptions in the original accident analysis.

UFSAR section 15.4.8.1, "Spectrum of Rod Cluster Control Assembly Ejection Accidents", subsection 15.4.8.2. "Calculation of Basic parameters", a, Ejected Rod Worths and Hot Channel Factors states that "The calculation (for ejected rod worths) is performed for the maximum allowed bank insertion at a given power level, as given by the rod insertion limits". For a case where one or more rod has dropped, those rods will be below their rod insertion limits, therefore the estimated rod worths of the OTHER rods are DIFFERENT than as assumed for the UFSAR accident analysis starting point.

Subsection e., Trip Reactivity Insertion", of this same section states that the Trip reactivity assumed is given in table 15.4-2 and included the effect of one stuck RCCA adjacent to the ejected rod. The table lists the assumed rod worth of the ejected rod at various power levels and times in core life. For a case where one or more rod has dropped, the worth of a postulated rod adjacent to an ejected rod will be DIFFERENT than as assumed for the UFSAR accident analysis starting point.

Subsection g. "Results", also provides specific reactivity values assigned to the hypothetical ejected rod worth for various points in core life and power levels.

REACTIVITY CONTROL SYSTEMS

3/4.1.3 MOVABLE CONTROL ASSEMBLIES

GROUP HEIGHT

LIMITING CONDITION FOR OPERATION

3.1.3.1 All full-length shutdown and control rods shall be OPERABLE and positioned within ± 12 steps (indicated position) of their group step counter demand position.

APPLICABILITY: MODES 1* and 2*.

ACTION:

a. With one or more full-length rods inoperable because of being immovable as a result of excessive friction or mechanical interference or known to be untrippable, determine that the SHUTDOWN MARGIN requirement of Specification 3.1.1.1 is satisfied within 1 hour and be in HOT STANDBY within 6 hours.

b. With one full-length rod trippable but inoperable due to causes other than addressed by ACTION a., above, or misaligned from its group step counter demand height by more than ± 12 steps (indicated position), POWER OPERATION may continue provided that within 1 hour:

1. The rod is restored to OPERABLE status within the above alignment requirements, or

2. The rod is declared inoperable and the remainder of the rods in the group with the inoperable rod are aligned to within ± 12 steps of the inoperable rod while maintaining the rod sequence and insertion limits of Specification 3.1.3.6. The THERMAL POWER level shall be restricted pursuant to Specification 3.1.3.6 during subsequent operation, or

3. The rod is declared inoperable and the SHUTDOWN MARGIN requirement of Specification 3.1.1.1 is satisfied. POWER OPERATION may then continue provided that:

a) A reevaluation of each accident analysis of Table 3.1-1 is performed within 5 days; this reevaluation shall confirm that the previously analyzed results of these accidents remain valid for the duration of operation under these conditions;

b) The SHUTDOWN MARGIN requirement of Specification 3.1.1.1 is determined at least once per 12 hours;

*See Special Test Exceptions Specifications 3.10.2 and 3.10.3.

REACTIVITY CONTROL SYSTEMS

BASES

3/4.1.3 MOVABLE CONTROL ASSEMBLIES

The specifications of this section ensure that: (1) acceptable power distribution limits are maint~~ained, (2) the minimum SHUTDOWN MARGIN is maintained, and~~ (3) the potential effects of rod misalignment on associated accident analyses are limited. OPERABILITY of the contr~~ol rod position indicators is required to determine control rod positi~~ons and thereby ensure compliance with the control rod alignment and insertion limits. Verification that the Digital Rod Position Indicator agrees with the demanded position within ± 12 steps at 24, 48, 120, and 228 steps withdrawn for the Control Banks and 18, 210, and 228 steps withdrawn for the Shutdown Banks provides assurances that the Digital Rod Position Indicator is operating correctly over the full range of indication. Since the Digital Rod Position Indication System does not indicate the actual shutdown rod position between 18 steps and 210 steps, only points in the indicated ranges are picked for verification of agreement with demanded position.

The ACTION statements which permit limited variations from the basic requirements are accompanied by additional restrictions which ensure that the original design criteria are met. Misalignment of a rod requires measurement of peaking factors and a restriction in THERMAL POWER. These restrictions provide assurance of fuel rod integrity during continued operation. In addition, those safety analyses affected by a misaligned rod are reevaluated to confirm that the results remain valid during future operation.

The maximum rod drop time restriction is consistent with the assumed rod drop time used in the safety analyses. Measurement with rods at their individual mechanical fully withdrawn position, T_{avg} greater than or equal to 551°F and all reactor coolant pumps operating ensures that the measured drop times will be representative of insertion times experienced during a Reactor trip at operating conditions.

The fully withdrawn position of shutdown and control banks can be varied between 225 and the mechanical fully withdrawn position (up to 232 steps), inclusive. An engineering evaluation was performed to allow operation to the 232 step maximum. The 225 to 232 step interval allows axial repositioning to minimize RCCA wear.

Control rod positions and OPERABILITY of the rod position indicators are required to be verified on a nominal basis of once per 12 hours with more frequent verifications required if an automatic monitoring channel is inoperable. These verification frequencies are adequate for assuring that the applicable LCOs are satisfied.

TABLE 3.1-1

ACCIDENT ANALYSES REQUIRING REEVALUATION
IN THE EVENT OF AN INOPERABLE FULL-LENGTH ROD

Rod Cluster Control Assembly Insertion Characteristics

Rod Cluster Control Assembly Misalignment

Loss of Reactor Coolant from Small Ruptured Pipes or from Cracks in Large Pipes Which Actuates the Emergency Core Cooling System

Single Rod Cluster Control Assembly Withdrawal at Full Power

Major Reactor Coolant System Pipe Ruptures (Loss-of-Coolant Accident)

Major Secondary Coolant System Pipe Rupture

Rupture of a Control Rod Drive Mechanism Housing (Rod Cluster Control Assembly Ejection)

SEABROOK STATION UFSAR	ACCIDENT ANALYSES TABLE 15.4-2	Revision: 10 Sheet: 1 of 1

Table 15.4-2 **Parameters Used In The Rcca Ejection Accident**

Time In Life – Power	BOL-HFP	BOL-HZP	EOL-HFP	EOL-HZP
Power level, %	100	0	100	0
Ejected rod worth (% Δρ)	0.25	0.78	0.25	0.85
Delayed neutron fraction, %	0.54	0.54	0.44	0.44
Feedback reactivity weighing	1.355	2.081	1.486	3.765
Trip reactivity (% Δρ)	4.0	2.0	4.0	2.0
F_q before rod ejection	2.5	--	2.5	--
F_q after rod ejection	6.0	11.5	7.0	26.0
Number of Operation Pumps	4	2	4	2
Max. Fuel C/L Temperature, °F	4929	3835	4850	3938
Max. Fuel Avg. Temperature, °F	3795	3340	3796	3516
Max. Fuel stored energy, cal/gm [Btu/lb]	163.7 [294.7]	140.7 [253.2]	163.8 [294.8]	149.4 [268.9]
Fuel Melt (%)	0.31	0	1.79	0

SEABROOK STATION UFSAR	ACCIDENT ANALYSES Reactivity and Power Distribution Anomalies	Revision 12 Section 15.4 Page 2

Procedural controls restrict rod motion if the power range nuclear instruments are inoperable. With RCA Tave less than 551°F and power range NIs inoperable, the motor generator sets can only be energized if the RCS is borated to greater than the all rods out value or if alternate means have been established to ensure that the control and shutdown rods are not capable of being withdrawn.

Although the reactor is normally brought to power from a subcritical condition by means of RCCA withdrawal, initial startup procedures with a clean core call for boron dilution on RCCA withdrawal. The maximum rate of reactivity increase in the case of boron dilution is less than that assumed in this analysis (see Subsection 15.4.6, "Chemical and Volume Control System Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant").

The RCCA drive mechanisms are wired into preselected bank configurations which are not altered during reactor life. These circuits prevent the RCCAs from being automatically withdrawn in other than their respective banks. Power supplied to the banks is controlled such that no more than two banks can be withdrawn at the same time and in their proper withdrawal sequence. The RCCA drive mechanisms are of the magnetic latch type, and coil actuation is sequenced to provide variable speed travel. The maximum reactivity insertion rate analyzed in the detailed plant analysis is that occurring with the simultaneous withdrawal of the combination of two sequential control banks having the maximum combined worth at maximum speed.

This event is classified as an ANS Condition II incident (an incident of moderate frequency) as defined in Subsection 15.0.1.

The neutron flux response to a continuous reactivity insertion is characterized by a very fast rise, terminated by the reactivity feedback effect of the negative Doppler coefficient. This self limitation of the power excursion is of primary importance since it limits the power to a tolerable level during the delay time for protective action. Should a continuous RCCA withdrawal accident occur, the transient will be terminated by the following automatic features of the Reactor Protection System:

a. Source Range High Neutron Flux Reactor Trip - Actuated when either of two independent source range channels indicates a neutron flux level above a preselected manually adjusted setpoint. This trip function may be manually bypassed only after an intermediate range flux channel indicates a flux level above a specified level. It is automatically reinstated when both intermediate range channels indicate a flux level below a specified level.

b. Intermediate Range High Neutron Flux Reactor Trip - Actuated when either of two independent intermediate range channels indicates a flux level above a preselected manually adjustable setpoint. This trip function may be manually bypassed only after two of the four power range channels are reading above approximately 10 percent of full power, and is automatically reinstated when three of the four power range channels indicate a power level below this value.

The minimum design shutdown margin available for this plant at hot zero power (HZP) may be reached only at end of life in the equilibrium cycle. This value includes an allowance for the worst stuck rod, an adverse xenon distribution, conservative Doppler and moderator defects, and an allowance for calculational uncertainties. Physics calculations have shown that the effect of two stuck RCCAs (one of which is the worst ejected rod) is to reduce the shutdown by about an additional 1%Δk. Therefore, following a reactor trip resulting from an RCCA ejection accident, the reactor will be subcritical when the core returns to HZP.

Depressurization calculations have been performed assuming the maximum possible size break (2.75 inch diameter) located in the reactor pressure vessel head. The results show a rapid pressure drop and a decrease in system water mass due to the break. The emergency core cooling system (ECCS) is actuated on low pressurizer pressure within 1 minute after the break. The RCS pressure continues to drop and reaches saturation (1100 to 1300 psi depending on the system temperature) in about 2 to 3 minutes. Due to the large thermal inertia of primary and secondary system, there has been no significant decrease in the RCS temperature below no-load by this time, and the depressurization itself has caused an increase in shutdown margin by about 0.2%Δk due to the pressure coefficient. The cooldown transient could not absorb the available shutdown margin until more than 10 minutes after the break. The addition of borated safety injection flow starting one minute after the break is much more than sufficient to ensure that the core remains subcritical during the cooldown.

f. Reactor Protection

Reactor protection for a rod ejection is provided by high neutron flux trip (high and low setting) and high rate of neutron flux increase trip. These protection functions are part of the reactor trip system. No single failure of the reactor trip system will negate the protection functions required for the rod ejection accident, or adversely affect the consequences of the accident.

g. Results

Cases are presented for both beginning and end of life at zero and full power.

(1) Beginning of Cycle, Full Power

Control bank D was assumed to be inserted to its insertion limit. The worst ejected rod worth and hot channel factor were conservatively calculated to be 0.25%Δρ and 6.0 respectively. The maximum fuel stored energy was 164 cal/gm. The peak hot spot fuel center temperature reached melting, conservatively assumed at 4900°F. However, melting was restricted to less than 10% of the fuel pellet.

SEABROOK STATION UFSAR	ACCIDENT ANALYSES Reactivity and Power Distribution Anomalies	Revision 12 Section 15.4 Page 38

(2) Beginning of Cycle, Zero Power

For this condition, control bank D was assumed to be fully inserted and banks B and C were at their insertion limits. The worst ejected rod is located in control bank D and has a worth of 0.78%Δρ and a hot channel factor of 11.5. The maximum fuel stored energy was 141 cal/gm. The peak fuel center temperature was 3835°F.

(3) End of Cycle, Full Power

Control bank D was assumed to be inserted to its insertion limit. The ejected rod worth and hot channel factors were conservatively calculated to be 0.25%Δρ and 7.0 respectively. The maximum fuel stored energy was 164 cal/gm. The peak fuel center temperature was 4850°F.

(4) End of Cycle, Zero Power

The ejected rod worth and hot channel factor for this case were obtained assuming control bank D to be fully inserted and banks B and C at their insertion limits. The results were 0.85%Δρ and 26.0 respectively. The maximum fuel stored energy was 149 cal/gm. The peak fuel center temperature was 3938°F. The Doppler weighting factor for this case is significantly higher than that of the other cases due to the very large transient hot channel factor.

A summary of the cases presented above is given in Table 15.4-2. The nuclear power and hot spot fuel and clad temperature transients for the worst cases (beginning of life full power and end of life zero power) are presented in Figure 15.4-10 and Figure 15.4-11. The calculated sequence of events for these worst case rod ejection accidents is presented in Table 15.4-1. For all cases, reactor trip occurs very early in the transient, after which the nuclear power excursion is terminated. As discussed previously, the reactor will remain subcritical following reactor trip.

The ejection of an RCCA constitutes a break in the RCS, located in the reactor pressure vessel head. Following the RCCA ejection, the operator would follow the same emergency instructions as for any other LOCA to recover from the event.

NRC Resolution:

Question 83:

The following conditions exist:

- The plant was operating in Mode 1 at 100% power.
- A fire in the Seismic Monitoring Cabinet has forced an evacuation of the Control Room.
- The Crew is responding to the Remote Safe Shutdown (RSS) Panels.

In accordance with OS1200.02, "Safe Shutdown and Cooldown From the Remote Safe Shutdown Facilities", which of the following is the prescribed method of ensuring sufficient RCS boration for Cold shutdown in this condition?

A. At the RSS panels shift CS pump suction to the RWST. Start borating using a Boric Acid Transfer Pump and the Emergency Boration valve. Inject Boric Acid required for Cold Shutdown by calculation or sample.

B. Prior to leaving the Control Room start a boration using a Boric Acid Transfer Pump and the Emergency Boration valve. Monitor WR Excore Neutron Flux less than 1.0 E-3% at RSS panel throughout the cooldown to ensure sufficient boration.

C. Prior to leaving the Control Room start a boration using a Boric Acid Transfer Pump and the Emergency Boration valve. Verify sufficient Boric Acid for cold shutdown injected by sample or calculated volume when the RSS panels are manned.

D. At the RSS panels shift CS pump suction to the RWST. Start borating using a Boric Acid Transfer Pump and the Emergency Boration valve. Monitor WR Excore Neutron Flux remains less than 1.0 E-3% at RSS panel throughout the cooldown to ensure sufficient boration.

Answer: A

Original regrade request comments:
ES-403 D.1.b Re-grade criteria; newly discovered technical information shows that two answers are correct. Answer "D" is also a correct answer as explained below.

The stem of the question intended to test the students knowledge of the method used to ensure sufficient boration has been added to the plant to achieve cold shutdown conditions when operating from the Remote Safe Shutdown (RSS) panel.

In a normal plant shutdown and cooldown from the Main Control Room the plant is borated to meet the shutdown margin requirements for cold shutdown condition prior to the initiation of the cooldown. This boration must be verified by direct sample of the RCS before proceeding. In a RSS shutdown the cooldown is initiated before the boration is started, so verification of adequate shutdown margin is managed under more dynamic conditions.

In OS1200.02 the boration is initiated as described in the first and second sentences of both answer "A" and answer "D". The procedure starts this boration in two different steps, step 4 or step 14. Step 4 of the procedure is a continuous action step that directs the operators to monitor WR Excore Neutron Flux level less than 1.0 E-3%. The RNO for flux level greater than 1.0 E-3% directs shifting CS pump suction to the RWST and starting a boration. Step 14 records initial boric acid storage tank levels, then aligns the charging system suction to a borated water source. A plant cooldown is then initiated in step 17. Boron (via the aligned borated water suction source) is then added as necessary as the RCS volume contracts during the cooldown to maintain Pressurizer level between 20% and 80% (step 15) or WR Excore Neutron Flux level less than 1.0 E-3% (step 4). An attempt is made to verify RCS boron concentration is greater than the concentration required by RE-18, "Shutdown Margin Values" by RCS sample (Step 24 c) before the plant is aligned to RHR. If accident conditions prevent verification by sample then an indirect determination of RCS boron concentration is utilized. The amount of boric acid that has been pumped from the boric acid storage tanks is used to calculate the inferred change in RCS boron concentration. This measurement can not verify that the volume that left the boric acid storage tanks has been successfully added to the RCS, but the expected results are backed up by the provided RSS process monitoring instrumentation.

UFSAR section 7.4, "Systems Required for Safe Shutdown", subsection 7.4.5.6 (Section 7.4, page 4), Process Monitoring states that "Monitoring of various vital plant parameters relied on to achieve and verify safe shutdown is available from redundant instrumentation in the main control room and the RSS locations. This instrumentation is listed in Table 7.4-1.". The Excore Wide Range Neutron detectors referred to in OS1200.02, step 4 are identified in Table 7.4-1 as used for "Reactivity Monitoring and Control".

Subsection 7.4.6, "Design Basis and Analysis" (Section 7.4, page 8) states: "In the unlikely event that the main control room is uninhabitable, alternate control provisions are provided at the RSS locations. Safety is not adversely affected by Event 1, uncontrolled boron dilution (see Subsection 15.4.6)". The Boron dilution monitors are only available in the main control room, so a boron dilution event can only be detected by monitoring of the WR Excore Neutron Flux detectors.

An addition caution prior to step 29 also warns the operators to monitor plant conditions for insufficient boron addition. The caution states: "SDM (Shutdown margin) should be monitored during initial RHR recirculation to the RCS." The can only be accomplished by monitoring of the Excore Wide Range Neutron detectors to verify that the core is protected from an inadvertent dilution when RHR is placed in service.

Answer A remains correct. The remote safe shutdown procedure directs shifting CS pump suction to the RWST, and step 14 of OS1200.02 starts a Boric Acid Transfer Pump and opens the Emergency Boration valve. The required amount of Boric acid can be added until it is verified by sample or, if that is not available, by calculated volume. Step 13 of OS1200.02 performs the initial sample of RCS boron, a caution prior to step 17 warn that boron greater than RE-18 requirements must be added, and step 24 provides the "loop" to check the amount of boron added by sample or by calculation.

Recommendation: Accept two answers, A and D.

Technical Reference(s)
OS1200.02, " Safe Shutdown and Cooldown From the Remote Safe Shutdown Facilities". UFSAR Section 7.4, "Systems Required for Safe Shutdown" including UFSAR table 7.4-1, "Equipment Required for Safe Shutdown"

Number	Title	Rev./Date
OS1200.02	SAFE SHUTDOWN AND COOLDOWN FROM THE REMOTE SAFE SHUTDOWN FACILITIES	12 CHG 02 07/31/08

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
4	***Monitor Excore Wide Range Neutron Flux:**	
	a. Neutron flux - LESS THAN 1.0 E-3% REACTOR POWER	a. Align borated water source, as follows: 1) Start at least one boric acid transfer pump:
	CP-108A / CP-108B	
	NI-6690 / NI-6691	• CS-P-3A at MCC-512 - OR - • Start CS-P-3B at MCC-612
		2) Open CS-V426 at MCC-612.
		IF valve can NOT be operated, THEN locally open valve.
		3) Open RWST suction supply:
		• CS-LCV-112D at CP-108A
		- OR -
		• CS-LCV-112E at CP-108B
		4) Close VCT suction supply:
		• CS-LCV-112B at CP-108A
		- OR -
		• CS-LCV-112C at CP-108B
		5) Open RCS cold leg injection valve:
		• SI-V138 at CP-108A
		- OR -
		• SI-V139 at CP-108B
		6) WHEN neutron flux is decreasing, THEN stop boration:
		• Close SI-V138
		• Close SI-V139
		• Stop boric acid transfer pumps
		• Close CS-V426

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Number	Title	Rev./Date
OS1200.02	SAFE SHUTDOWN AND COOLDOWN FROM THE REMOTE SAFE SHUTDOWN FACILITIES	12 CHG 02 07/31/08

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
13	**Sample RCS For Boron Concentration:**	
	a. Align sample valves for loop 1 from CP-108A:	a. Align sample valves for loop 3 from CP-108B:
	1) Close MCC-522 feeder breaker	1) Close MCC-622 feeder breaker
	2) Unlock and close breaker for loop 1 sample valve:	2) Unlock and close breaker for loop 3 sample valve:
	• RC-FV-2894 at MCC-522	• RC-FV-2896 at MCC-622
	3) Align loop 1 RCS sample:	3) Align loop 3 RCS sample:
	• RC-FV-2832 – OPEN	• RC-FV-2833 – OPEN
	• RC-FV-2894 – OPEN	• RC-FV-2896 – OPEN
	4) Notify Chemistry to sample the RCS for boron concentration	
	b. Record boron concentration Boron PPM __________	b. IF sample can NOT be obtained, THEN record last RCS boron concentration:
	Sample Time __________	Boron PPM ________
	c. Close RCS sample valves:	
	<u>CP-108A</u> RC-FV-2832 - CLOSE RC-FV-2894 - CLOSE	
	<u>CP-108B</u> RC-FV-2833 - CLOSE RC-FV-2896 - CLOSE	
	d. Open feeder breaker: • CP-108A – MCC-522 • CP-108B – MCC-622	

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Number	Title	Rev./Date
OS1200.02	SAFE SHUTDOWN AND COOLDOWN FROM THE REMOTE SAFE SHUTDOWN FACILITIES	12 CHG 02 07/31/08

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
14	**Establish Plant Configuration For Reactivity And Inventory Control:**	
	a. Record the Boric Acid Tank Levels:	

TANK	INSTRUMENT	RSS CONTROL PANEL
BA-TK-4A	CS-LI-7446	CP-108A
BA-TK-4B	CS-LI-7464	CP-108B

BA TK-4A ____________________

BA-TK-4B ____________________

b. Locally isolate RMW to RCS makeup system:

1) Close RMW-V34 boric acid blender isolation

2) Close RMW-V31, boric acid blender and charging pump suction isolation

3) Close RMW-V36, charging pump suction isolation

c. Locally align the boric acid tank with the highest level to both boric acid transfer pump suctions:

BA-TK-4A	BA-TK-4B
CS-V410 - OPEN	CS-V416 - OPEN
CS-V437 - OPEN	CS-V437 - OPEN
CS-V1207 - OPEN	CS-V1207 - OPEN
CS-V416 - CLOSE	CS-V410 - CLOSE
CS-V431 - CLOSE	CS-V423 - CLOSE

Step continued on the next page.

Number	Title	Rev./Date
OS1200.02	SAFE SHUTDOWN AND COOLDOWN FROM THE REMOTE SAFE SHUTDOWN FACILITIES	12 CHG 02 07/31/08

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
	d. Align charging pump suction to RWST: 1) RWST suction supply - OPEN • CP-108A - CS-LCV-112D	d. Locally open valves. IF RWST can NOT be aligned, THEN refer to ATTACHMENT B for gravity feed lineup. Go to Step 14f.
	- OR -	
	• CP-108B - CS-LCV-112E	
	2) VCT suction supply - CLOSED	
	• CP-108A - CS-LCV-112B	
	- OR -	
	• CP-108B - CS-LCV-112C	
	e. Align ON-LINE boric acid tank:	
	1) Start ON-LINE boric acid transfer pump: • CS-P-3A - MCC 512 - OR - • CS-P-3B - MCC-612	1) IF a boric acid transfer pump can NOT be started, THEN align gravity feed per ATTACHMENT B AND go to Step 14f.
	2) Establish boric acid flow: • CS-V426 MCC-612 - OPEN	2) IF valve cannot be operated, THEN open valve locally.
	f. Isolate normal letdown by opening the following circuits:	
	• RC-LCV-459 - PP-122B CKT #17	
	• RC LCV-460 - PP-122B CKT #1	
	g. Isolate RCS charging header:	
	1) CP-108A - CS-V142 CLOSE	
	2) CP-108B - CS-V143 CLOSE	
	Step continued on the next page.	

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Number	Title	Rev./Date
OS1200.02	SAFE SHUTDOWN AND COOLDOWN FROM THE REMOTE SAFE SHUTDOWN FACILITIES	12 CHG 02 07/31/08

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
15	**Check Plant Conditions:**	
	a. Pressurizer level - 20% TO 80%	a. Perform the following:
	CP-108A / CP-108B	• IF level is high:
	RC-LI-7334 / RC-LI-7333	1) Increase steam dump.
	RC-LR-7334 / RC-LR-7333	2) Decrease seal injection flow by locally adjusting applicable charging pump flow control bypass valve:
		CS-P-2A / CS-P-2B
		CS-V221 / CS-V219
		- OR -
		• IF level is low:
		1) Decrease steam dump.
		2) Increase seal injection flow by locally adjusting applicable charging pump flow control bypass valve:
		CS-P-2A / CS-P-2B
		CS-V221 / CS-V219

Step continued on the next page.

Number	Title	Rev./Date
OS1200.02	SAFE SHUTDOWN AND COOLDOWN FROM THE REMOTE SAFE SHUTDOWN FACILITIES	12 CHG 02 07/31/08

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
CAUTION	• *A boric acid tank volume greater than RE-18 requirement must be injected into the RCS, during cool down, to ensure adequate shut down margin.* • *Maintain PZR level between 50% to 80%.*	
17	**Commence RCS Cooldown:**	
	a. Defeat SSPS Train A and Train B output by opening the following circuits:	
	• A Train SSPS - PP-1A CKT #11	
	• B Train SSPS - PP-1B CKT #11	
	b. Maintain RCS subcooling greater than 100°F per ATTACHMENT A, COOLDOWN LIMITATIONS CURVE	
	c. Adjust SG ASDVs to achieve a cooldown rate - LESS THAN OR EQUAL TO 50°F/HR BY COLD LEG INDICATION:	c. Locally adjust valves for cooldown.

RCS Cold Leg	Temperature Instrument
CP-108A	
LOOP 1	RC-TR-9406 RC-TI-9410
CP-108B	
LOOP 4	RC-TR-9407 RC-TI-9411

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
	d. Maintain all SG pressures - EQUAL DURING COOLDOWN	
	e. Maintain SG wide range - 70% TO 90%:	e. Adjust EFW flow as necessary.

Step continued on the next page.

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Number	Title	Rev./Date
OS1200.02	SAFE SHUTDOWN AND COOLDOWN FROM THE REMOTE SAFE SHUTDOWN FACILITIES	12 CHG 02 07/31/08

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
24	**Sample RCS For Boron Concentration:**	
	a. Align sample valves for loop 1 from CP-108A:	a. Align sample valves for loop 3 from CP-108B:
	1) Close MCC-522 feeder breaker	a) Close MCC-622 feeder breaker
	2) Unlock and close breaker for loop 1 sample valve:	b) Unlock and close breaker for loop 3 sample valve:
	• RC-FV-2894 at MCC-522	• RC-FV-2896 at MCC-622
	3) Align loop 1 RCS sample:	c) Align loop 3 RCS sample:
	• RC-FV-2832 – OPEN	• RC-FV-2833 – OPEN
	• RC-FV-2894 – OPEN	• RC-FV-2896 – OPEN
	4) Notify Chemistry to sample the RCS for boron concentration	
	b. Record boron concentration Boron PPM ________	b. IF sample can NOT be obtained, THEN verify a boric acid tank volume greater than RE-18 requirement is injected into the RCS.
	Sample Time ________	
	c. Verify boron sample concentration is greater than RE-18 requirements.	c. Continue RCS makeup from the boric acid tank.
	d. Close RCS sample valves:	
	CP-108A	
	RC-FV-2832 - CLOSE	
	RC-FV-2894 - CLOSE	
	CP-108B	
	RC-FV-2833 - CLOSE	
	RC-FV-2896 - CLOSE	
	e. Open feeder breaker:	
	• CP-108A – MCC-522 • CP-108B – MCC-622	

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Number	Title	Rev./Date
OS1200.02	SAFE SHUTDOWN AND COOLDOWN FROM THE REMOTE SAFE SHUTDOWN FACILITIES	12 CHG 02 07/31/08

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
CAUTION	*SDM should be monitored during initial RHR recirculation to RCS. Each RHR loop contains approximately 3100 gallons.*	
29	**Place One RHR Train In Operation:**	
	a. Locally sample RHR train for boron concentration:	
	• A RHR - RH-V8	
	- OR -	
	• B RHR - RH-V44	
	b. Align RHR flow valves to full flow cooling by opening breaker:	
	• RHR Train A flow control valves - PP-112A CKT #2	
	- OR -	
	• RHR Train B flow control valves - PP-112B CKT #2	
	c. Locally align valves for RHR operation:	

RHR Train	Valve	Position
A RHR	CBS-V2	CLOSED
	CC-V145	OPEN
	RH-FCV-610	OPEN
	RH-FCV-606	CLOSED
B RHR	CBS-V5	CLOSED
	CC-V272	OPEN
	RH-FCV-611	OPEN
	RH-FCV-607	CLOSED

Step continued on the next page.

7.4.5.5 Plant Cooling System

Operation of at least one service water/PCCW train is required to maintain equipment cooling and for subsequent RHR operation. Intake tunnel failure that results in the complete loss of the seawater supply to the service water pumps or failure of nonseismic service water piping large enough to prevent adequate cooling of safety systems will result in automatic actuation of the cooling tower on low service water pump discharge pressure. The TA signal is also generated when the Cooling Tower is providing the cooling water to the station, and a loss of offsite power event occurs. Intake tunnel failure with subsequent cooling tower actuation is only applicable to safe shutdown from the main control room. RSS does not require cooling tower actuation. If the cooling towers are actuated there are manual actions required at the tower to detect a loss of inventory due to pipe or valve failure and to manually close the spray header bypass valve to start flow into the spray header after the basin is heated sufficiently to prevent icing. Cooling tower actuation, loss of offsite power, or safety injection, isolates the nonseismic SW piping to ensure adequate flow to the safety users.

7.4.5.6 Process Monitoring

Monitoring of various vital plant parameters relied on to achieve and verify safe shutdown is available from redundant instrumentation in the main control room and the RSS locations. This instrumentation is listed in Table 7.4-1.

7.4.5.7 HVAC

Operation of the ventilation/cooling systems for the diesel-generator building, primary component cooling water pump area, Emergency Feedwater Pumphouse, Service Water Pumphouse, switchgear rooms and containment enclosure area is required to maintain the long-term operability of the equipment within these heat generating areas and keep temperatures below equipment limitations. The equipment function and safety evaluations for these systems are explained in the various subsections of Section 9.4.

7.4.5.8 Sampling

Capability to obtain grab samples of the RCS is available to determine boron concentration for the cooldown. The boron concentration in the RHR system will also be verified prior to system initiation. Valves operated for sampling are not considered active unless they serve other safety functions such as containment isolation.

SEABROOK STATION UFSAR	INSTRUMENTATION AND CONTROLS Systems Required for Safe Shutdown	Revision 12 Section 7.4 Page 8

Safety grade backup air supplies have been provided to components which must remain operable for safe shutdown. Refer to Updated FSAR Section 9.3 for further discussion.

The station Service Water System is explained in Subsection 9.2.1. The safety evaluation is presented in Subsection 9.2.1.3. The Primary Component Cooling Water System is explained in Subsection 9.2.2 and the safety evaluation is presented in detail in Subsection 9.2.2.3.

The selection of instrumentation and controls for safe shutdown has included consideration of the event consequences that might jeopardize safe shutdown conditions. The event consequences that are germane are those that would tend to degrade the capabilities for boration, adequate supply for emergency feedwater, and residual heat removal.

The results of the analyses are presented in Chapter 15. Of these, the following events will produce the most severe consequences that are pertinent:

1. Uncontrolled boron dilution (see Subsection 15.4.6)
2. Loss of normal feedwater (see Subsection 15.2.7)
3. Loss of external electrical load and/or turbine trip (see Subsections 15.2.2 and 15.2.3)
4. Loss of nonemergency AC power to the station auxiliaries (Loss of Offsite Power). See Subsection 15.2.6.

It is shown by these analyses, that safety is not adversely affected by these events, assuming the equipment indicated in Subsection 7.4.7 is available in the main control room to control and/or monitor shutdown. These available systems will allow maintenance of hot standby and cooldown to cold shutdown even during the events listed above which would tend toward a return to criticality or a loss of heat sink.

In the unlikely event that the main control room is uninhabitable, alternate control provisions are provided at the RSS locations. Safety is not adversely affected by Event 1, uncontrolled boron dilution (see Subsection 15.4.6). Events 2, 3 and 4 do not have an adverse effect since the remote safe shutdown equipment can be powered by emergency power, and a plant trip initiated by main control room evacuation will put the plant in a safe condition.

The results of the analysis which determined the applicability of the NRC General Design Criteria, IEEE Standard 279-1971, applicable NRC Regulatory Guides, and other industry standards, to the equipment required for safe shutdown, are presented in Table 7.1-1.

SEABROOK STATION UFSAR	ENGINEERED SAFETY FEATURES TABLE 7.4-1	Revision: 12 Sheet: 6 of 13

			Instrumentation Location			
Description	Device	RSS Control Location	MCB	CP108A	CP108B	Local
SI Accum. TK-9A Isol. Vlv.	SI-V-3	CP-108A				
SI Accum. TK-9B Isol. Vlv.	SI-V-17	CP-108B				
SI Accum. TK-9C Isol. Vlv.	SI-V-32	CP-108A				
SI Accum. TK-9D Isol. Vlv.	SI-V-47	CP-108B				
SI Accum. TK-9A Vent Vlvs.	SI-FV-2475, 2476	CP-108B				
SI Accum. TK-9B Vent Vlvs.	SI-FV-2482, 2483	CP-108A				
SI Accum. TK-9C Vent Vlvs.	SI-FV-2477, 2486	CP-108B				
SI Accum. TK-9D Vent Vlvs.	SI-FV-2495, 2496	CP-108A				
Bus E52 Feeder Breaker to MCC E522	AW9	CP-108A				
Bus E62 Feeder Breaker to MCC E622	AW0	CP-108B				
c. Reactivity Monitoring and Control:						
Neutron Flux Indicators/ Monitors (Excore)						
Intermediate Range Flux	NI-NI-6690-2		X			
Intermediate Range Flux	NI-NI-6690-3			X		
Source Range Flux	NI-NI-6690-4			X		
Intermediate Range Flux	NI-NI-6691-2		X			
Intermediate Range Flux	NI-NI-6691-3				X	
~~Source Range Flux~~	~~NI-NI-6691-4~~				~~X~~	
Shutdown Monitor	NI-NM-6690-1		X			

(continued to next page

Additional regrade request comments for question 83:

Question 83 established some initial conditions that (1) A fire in the Seismic Monitoring Cabinet has forced an evacuation of the Control Room and (2) The Crew is responding to the Remote Safe Shutdown (RSS) Panels.

The question then asks: "In accordance with OS1200.02, "Safe Shutdown and Cooldown From the Remote Safe Shutdown Facilities", which of the following is the prescribed method of ensuring sufficient RCS boration for Cold shutdown in this condition?"

The request for a regrade has asserted that answer D is also a correct answer so two answers should be credited. Answer D states:

D. At the RSS panels shift CS pump suction to the RWST. Start borating using a Boric Acid Transfer Pump and the Emergency Boration valve. Monitor WR Excore Neutron Flux remains less than 1.0 E-3% at RSS panel throughout the cooldown to ensure sufficient boration.

The initial request for regrade differentiated between the methodology of a normal plant shutdown, as opposed to the accelerated shutdown and cooldown used at the RSS panel. The request also used the design bases discussion provided in UFSAR chapter 7.4, "Systems required for Safe Shutdown".

The design bases of the Remote safe shutdown facilities are further discussed in Appendix R of the UFSAR. The introduction section provides a description of the purposes of the sub systems credited for Remote Safe shutdown function. In this section it establishes that: "reactivity control function(s) shall be capable of achieving and maintaining cold shutdown reactivity conditions" and that "the process monitoring functions shall be capable of providing direct readings of the process variables necessary to perform and control the (above) functions. (see excerpt on next page). Note that, for the concept of "Remote Safe Shutdown" two separate and distinct end conditions are described: achieving and maintaining cold shutdown.

SEABROOK STATION	Fire Protection of Safe Shutdown Capability 10CFR50, Appendix R Introduction	Rev. 5 Section 1 Page 1-1

INTRODUCTION

General Design Criterion 3, "Fire Protection," of Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50" Licensing of Production and Utilization Facilities" requires that structures, systems and components important to safety shall be designed and located to minimize, consistent with other safety requirements, the probability and effects of fires.

Appendix R, "Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979" to 10 CFR Part 50 was issued on November 19, 1980 (45 FR 76602). Paragraph III.G, "Fire Protection of Safe Shutdown Capability," requires that fire damage be limited so that:

a. One train of systems necessary to achieve and maintain hot shutdown conditions from either the control room or emergency control station(s) is free of fire damage; and

b. Systems necessary to achieve and maintain cold shutdown from either the control room or emergency control station(s) can be repaired within 72 hours.

This requires each licensee to assess those areas of the plant"....where cables or equipment, including associated non-safety circuits that could prevent operation or cause maloperation due to hot shorts, open circuits, or shorts to ground of redundant trains of systems necessary to achieve and maintain hot shutdown conditions are located in the same fire area..." The regulation establishes separation requirements for areas outside of primary containment and inside noninerted containment.

Appendix R, paragraph III.L, "Alternative and Dedicated Shutdown Capability," establishes the following performance goals for the shutdown functions:

a. The reactivity control function shall be capable of achieving and maintaining cold shutdown reactivity conditions.

b. The reactor coolant makeup function shall be capable of maintaining the reactor coolant level within level indication in the pressurizer.

c. The reactor heat removal function shall be capable of achieving and maintaining decay heat removal.

d. The process monitoring function shall be capable of providing direct readings of the process variables necessary to perform and control the above functions.

e. The supporting functions shall be capable of providing process cooling, lubrication, etc., necessary to permit operation of the equipment used for Safe Shutdown functions.

Branch Technical Position CMEB 9.5-1 "Guidelines for Fire Protection for Nuclear Power Plants," Rev. 2, July 1981 reiterates the above requirements in Section C.5.b and C.5.c.

A specific discussion of the Bases and Positions of Safe Shutdown Capabilities is provided in sub-section 3.1. Section 3.1.2 defines Safe Shutdown as follows:

"Safe Shutdown" for purposes of the review is defined as a capability to bring the reactor from a 100 percent power operating condition to a "cold shutdown" condition. Included in this are conditions "hot standby," "hot shutdown," "cold shutdown," and maintenance of "cold shutdown." Note again there is a distinction in this definition between achieving cold shutdown and maintenance of cold shutdown. The term “shutdown margin” is also not discussed in this definition, as it would be for a normal reactor shutdown and cooldown evolution.

SEABROOK STATION	Fire Protection of Safe Shutdown Capability 10CFR50, Appendix R Safe Shutdown Capability	Rev. 9 Section 3.1 Page 3.1-1

SAFE SHUTDOWN CAPABILITY

3.1 <u>Discussion Of Bases And Positions</u>

3.1.1. <u>General</u>

10 CFR Part 50 Appendix R, Paragraph III.G.1 requires that fire damage be limited so that:

a. One train of systems necessary to achieve and maintain hot standby condition from either the control room or emergency control station(s) is free of fire damage; and

b. Systems necessary to achieve and maintain cold shutdown from either the control room or emergency control station(s) can be repaired within 72 hours.

Based on requirement "a" above, the design basis of Seabrook Station is that one train of systems necessary to achieve and maintain hot standby from the control room or the emergency control stations (hereafter designated the remote safe shutdown facilities) is free of fire damage.

Under this basis, Appendix R, Paragraph III.G.2 and III.G.3 will apply to the safe shutdown paths controlled from the main control room or the remote safe shutdown facilities. Any deviations from the III.G.2 and III.G.3 criteria will be with respect to the main control room or the remote safe shutdown facilities and is addressed in Sections 3.2.7, 3.3.9, 3.4.3 and in the List of Deviations Section 3.7 of this report. For fires in some areas of plant, alternative shutdown capabilities are provided as discussed in Sections 3.3 and 3.4.

This Section defines the bases and positions utilized in determining and reviewing the shutdown capabilities that will satisfy the requirements of Paragraph III.G. These capabilities can be utilized to safely shut down the reactor in the event of a fire in any area/zone of the plant.

3.1.2 <u>Safe Shutdown</u>

"Safe Shutdown" for purposes of the review is defined as a capability to bring the reactor from a 100 percent power operating condition to a "cold shutdown" condition. Included in this are conditions "hot standby," "hot shutdown," "cold shutdown," and maintenance of "cold shutdown."

Appendix R discusses the criteria used to determine what equipment is required to satisfy the Safe Shutdown function. This is given in section 3.1.5. The equipment is broken down into two broad functional areas; Hot Standby and Cold Shutdown. Included in the listed criteria for determination of this equipment is the qualifier: "The equipment is required to operate to permit a safe shutdown system to perform its safe shutdown function".

SEABROOK STATION	Fire Protection of Safe Shutdown Capability 10CFR50, Appendix R Safe Shutdown Capability	Rev. 9 Section 3.1 Page 3.1-3

3.1.4 **Determination of Safe Shutdown Functions**

The safe shutdown functions are determined by considering the performance goals established in Appendix R, Paragraph III.L.2. The systems or portions of systems necessary to satisfy safe shutdown are subsequently determined.

3.1.5 **Determination of Safe Shutdown Equipment**

Safe shutdown systems are the systems required to achieve the performance goals listed in Section 1. The equipment for these systems can be divided by function as Hot Standby (Reactor tripped and T-Avg above 350°F) and Cold Shutdown (Reactor tripped/and cool down of the Reactor Coolant System T-Avg equal to or below 200°F).

The following criteria are used to determine the equipment required for safe shutdown:

a. The equipment is required to operate to permit a safe shutdown system to perform its safe shutdown function.

b. The equipment's maloperation can prevent a safe shutdown system from performing the safe shutdown function.

c. The equipment is a process or electrical boundary for a safe shutdown system.

3.1.6 **Safe Shutdown System Boundaries**

The safe shutdown system process boundaries are established by the following devices:

a. Normally closed manual valve

b. Check valve

The equipment required to both achieve and MAINTAIN cold shutdown from the Remote Safe Shutdown Panel (the location stipulated in the question) is listed Table RSS 3.1.3.4-3. This table identifies whether the equipment is required to achieve hot standby or to either achieve or maintain cold shutdown. In this list the Wide Range Ex Core Neutron detectors are identified as "Required for: Cold Shutdown" (See attached table excerpt).

SEABROOK STATION	Fire Protection of Safe Shutdown Capability 10CFR50, Appendix R Safe Shutdown Capability	Revision 7 Table RSS 3.1.3.4-4

FUNCTION: PROCESS MONITORING

ITEM NO.	EQUIPMENT ID NO.	EQUIPMENT DESCRIPTION	P&ID/1-LINE DRAWING NO.	TRAIN	PHYSICAL LOCATION DRAWING NO.	FIRE AREA/ZONE	REQUIRED FOR: HOT STAND BY	REQUIRED FOR: COLD SHUT DOWN	POWER: ELEC	POWER: AIR	ELEC NODE	SUPPORTING CONTROL AND INSTRUMENTATION EQUIPMENT: EQUIPMENT ID NO.	EQUIPMENT DESCRIPTION	ELEC NODE	FIRE AREA/ZONE	CABLES	ELECTRICAL DRAWING NO.: SCHEM.	ELECTRICAL DRAWING NO.: CABLE	SUPPORTING SYSTEMS	REDUNDANT COUNTERPART	REMARKS
32	NI-NE-6691	Intermediate Range Thermal Neutron Flux Monitoring Detector	-	B	310565	C-F-1-Z	X	X	X	-	Q07	NI-EIT/13-52	120 V ac Circuit Breaker	EIT	CB-F-1B-A	NI1-XP9	310943		CBA-FN-32	NI-NE-6690	
												NI-EIT/14-52	120 V ac Circuit Breaker	EIT	CB-F-1B-A	NI1-XD1	EIT/13a	EIT/13b	CBA-FN-33		
												NI-EIT/15-52	120 V ac Circuit Breaker	EIT	CB-F-1B-A	XD1-QD0			EDE-PP-11F		
												NI-NI-6691-3&4	Excore Wide Range Thermal Neutron Flux Indicators	G2K	CB-F-1B-A	QD0-Q31					
												NI-NT-6691	Excore Wide Range Transmitters	XD1	ET-F-1C-A	G2K-QD0					
												NI-NM-6691	Excore Wide Range Signal Processor	QD0	CB-F-1B-A	QD7-XP9					
												NI-NM-6691J	Excore Wide Range Signal Processor Expansion Box	Q31	CB-F-1B-A	EIT-XD1					
												EDE-TBX-XP9	Junction Box	XP9	C-F-1-Z	EIT-QD0					
												EDE-MM-97	Electrical Penetration	XD1	C-F-1-Z, ET-F-1C-A	EIT-Q31					
33	CO-LISL-4002	Condensate Storage Tank Level Indicator	CO-20428	A/B	310245 509066	CST-F-1-[illegible]	-	X	-	-	R10	-	-	-	-	-	-	-	-	-	Note 1

(Magnified image for clarity below)

SEABROOK STATION	Fire Protection of Safe Shutdow Appendix Safe Shutdown C

FUNCTION: PROCESS M

ITEM NO.	EQUIPMENT ID NO.	EQUIPMENT DESCRIPTION	P&ID/1-LINE DRAWING NO.	TRAIN	PHYSICAL LOCATION DRAWING NO.	FIRE AREA/ZONE	REQUIRED FOR: HOT STAND BY	REQUIRED FOR: COLD SHUT DOWN	POWER: ELEC	POWER: AIR	ELEC NODE	SUPPORTING: EQUIPMENT ID N
32	NI-NE-6691	Intermediate Range Thermal Neutron Flux Monitoring Detector	-	B	310565	C-F-1-Z	X	X	X	-	Q07	NI-EIT/13-52
												NI-EIT/14-52
												NI-EIT/15-52
												NI-NI-6691-3&4
												NI-NT-6691
												NI-NM-6691
												NI-NM-6691J
												EDE-TBX-XP9
												EDE-MM-97

11.00 x 8.50 in

Conclusion:

As restated, the question asked:

- What is a prescribed method described in the Remote Safe Shutdown procedure…
- ..that utilizes equipment at the Remote Safe Shutdown panels…
- ..to ensure the plant is sufficiently borated to Cold Shutdown conditions…
- .. **for the conditions of plant shutdown and cooldown from the remote safe shutdown facilities.**

Appendix R equipment is required to satisfy a definition of Cold Shutdown that is different and unique from the classic definition. The RSS cold shutdown definition has two elements: achieving and maintaining Cold Shutdown. Appendix R of the UFSAR clearly identifies the Ex Core Wide Range Neutron detectors as process monitoring equipment required for Cold Shutdown. The Design criteria for the RSS equipment clearly states that the process monitoring functions **shall be capable of providing direct readings** of the process variables necessary to perform and control whatever functions are REQUIRED to achieve AND MAINTAIN cold shutdown conditions. No other process instrumentation is available in the list of credited equipment that provides **direct readings** of the ability to MAINTAIN the plant in Cold Shutdown.

Answer D provides a valid description of the methodology used to perform the addition of negative reactivity to the core from the Remote Safe Shutdown panel, and provides a valid, credited method to DIRECTLY observe the effectiveness of the reactivity addition.

Answer D is correct.

NRC Resolution:

QUESTION 100:

The following plant conditions exist:

- A SITE AREA EMERGENCY was declared 37 minutes ago.
- The Emergency Response plan facilities have NOT been activated yet.
- The on shift Work Control Supervisor has made the Notification to the States and NRC.
- Conditions have stabilized and the event no longer meets the Emergency Action Level criteria.

Who is responsible for termination of the classification?

A. ONLY the Response Manager

B. Response Manager or Site Emergency Director.

C. Response Manager or Short Term Emergency Director.

D. Site Emergency Director or Short Term Emergency Director.

Answer: B

Initial regrade request comments:
ES-403 D.1.b Re-grade criteria; Question had unclear conditions and did not provide the necessary information to answer the questions. No correct answer.

Initial Conditions stated in the question establish that a Site Area Emergency was declared 37 minutes ago. At this point the Shift Manager assumes the dual role of the Short Term Emergency Director (STED). **The second bullet of the question specifically state that the site emergency facilities are not manned. Without the Emergency Off-site Facility (EOF) or the Technical Support Center (TSC) the Response Manager (RM) and the Site Emergency Director (SED) positions are not filled so no turnover of responsibilities can occur. ER-1.1, "Classification of Emergencies", Section 2.2, "Shift Manger Responsibilities" states "Responsibility for classifying observed station conditions in accordance with the emergency classification system specified in this procedure and reclassifying the emergency as necessary until relieved by the SED".**

ER-1.1, "Classification of Emergencies", Section 1.1 Discussion, 11th paragraph also states "If emergency conditions are initially classified as an Alert or higher, and then subsequently reclassified to an Unusual Event, all ERO members should continue to report to their facilities. Although *activation of the Technical Support Center, Operational Support Center, and Emergency Operations Facility are not required* (italics added), the

ERO staff will be available to assist with event recovery efforts, interface with State emergency response personnel, and respond to information requests from the media, elected officials and industry organizations." No further discussion is provided concerning the case of an emergency condition that is classified above an alert, but subsequently cleared. ER-1.2, "Emergency Plan Activation", Section 1.1 Discussion, restates this in the 3rd paragraph.

The 4th paragraph of ER-1.2, "Emergency Plan Activation", Section 1.1 Discussion states "Once the initial emergency declaration is made, the associated ER 1.2 checklist for the Short Term Emergency Director (ER 1.2A, B, C or D) shall be implemented at least through to the completion of state notifications prior to terminating the emergency classification or reclassifying the emergency".

In order to have a correct answer for this question, a choice must be given that either states the event can not be terminated at this point, or, the EOF and/or the TSC must be activated in order to terminate the event.

Recommendation: Delete question

(continued on next page)

Technical Reference(s)

ER 1.1, section 1.1, section 2.2 and ER 1.2, section 1.1

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2.0 RESPONSIBILITIES

2.1 Unit Supervisor

Responsible for assuming the role of Short Term Emergency Director (STED) until the Shift Manager has reported to the Control Room.

2.2 Shift Manager

Responsible for classifying observed station conditions in accordance with the emergency classification system specified in this procedure and reclassifying the emergency as necessary until relieved by the Site Emergency Director.

2.3 Site Emergency Director

Responsible for analyzing changing station conditions and reclassifying the emergency classification in accordance with this procedure.

3.0 PRECAUTIONS

1. Final emergency classifications are contingent upon the evaluation and discretion of the Shift Manager or the Site Emergency Director. The Shift Manager or Site Emergency Director may make an emergency classification based on clear indications that the event trajectory meets the intent of the initiating condition, although the associated emergency action levels have not yet been met or exceeded.

2. Critical safety function status tree (CSFST) color displays must be sustained indications of continuous conditions. Conditions indicated by CSFST displays must be evaluated and verified using hardwired information before they are used as bases for emergency classifications or for protective action recommendations.

3. Offsite dose projections are required in the event that any of the following conditions occur:

   a. HI alarm on Wide Range Gas Monitor (WRGM) effluent rate monitor (RM-6528-4), or

   b. HI alarm on a Main Steam Line Monitor with an OPEN atmospheric steam dump valve (ASDV) or safety relief valve (SRV) on the affected line, or

   c. HI alarm on a Main Steam Line Monitor with the steam driven EFW pump running and fed from the affected line.

   At the discretion of the Shift Manager, offsite dose projections may be performed after the initial declaration is made based on other plant or radiological conditions.

4. An emergency declaration should be made as soon as possible after indications are available that an EAL has been exceeded, not to exceed 15 minutes unless warranted by extenuating circumstances.

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If the emergency-related indications completely clear before a declaration of an emergency classification level has been made, then no emergency classification is required. The Shift Manager shall notify the Emergency News Manager within one hour of the termination of the emergency-related indications that emergency-related indications briefly existed, but cleared prior to the declaration of an emergency classification. The Emergency News Manager will initiate state notifications per good neighbor notification procedures. The event shall be reported to the NRC in accordance with 10 CFR 50.72 and 50.73 per the Regulatory Compliance Manual, and within 1 hour of the event.

If emergency-related indications are received and later cleared, and after the fact it is determined that an emergency classification was warranted but not made, then no emergency classification is required. The Shift Manager shall notify the Emergency News Manager within one hour of discovery that an emergency classification was warranted but not declared and that emergency-related indications no longer exist. The Emergency News Manager will initiate state notifications per good neighbor notification procedures. The event shall be reported to the NRC in accordance with 10 CFR 50.72 and 50.73 per the Regulatory Compliance Manual, and within 1 hour of the event.

If emergency-related indications are received and reduce in severity, such that the emergency classification went from an earlier higher level to a current lower level, the current lower level emergency should be declared. State and NRC notifications shall be made in accordance with Procedure ER 1.2.

If emergency conditions are initially classified as an Alert or higher, and then subsequently reclassified to an Unusual Event, all ERO members should continue to report to their facilities. Although activation of the Technical Support Center, Operational Support Center, and Emergency Operations Facility are not required, the ERO staff will be available to assist with event recovery efforts, interface with State emergency response personnel, and respond to information requests from the media, elected officials and industry organizations.

When the EOF is activated, dose projection results used for classifying emergencies will normally originate in the EOF. The EOF will communicate the results to the Site Emergency Director for classification of the emergency. If dose projection results are obtained from another source (e.g., the TSC), the Site Emergency Director shall direct the Health Physics Coordinator to obtain the concurrence of the EOF Coordinator before reclassifying the emergency based on the A category EALs. (Protected: Ref. 6.12)

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1.0 OBJECTIVES

This procedure specifies the initial emergency response actions to be taken upon the classification of an UNUSUAL EVENT, ALERT, SITE AREA EMERGENCY or GENERAL EMERGENCY in accordance with the Seabrook Station Radiological Emergency Plan.

1.1 Discussion

Checklist actions should be performed in the order in which they are listed.

If an Unusual Event is declared, Primary Responders shall respond per Procedure ER 1.2, Section 5.0, even if notified of the termination of the Unusual Event. For an Unusual Event response, on-duty Primary Responders who are directed in Section 5.0 to contact the Control Room shall **not** attempt to call on-duty Operations personnel in the Control Room until their pagers have activated. On-duty Primary Responders who are directed to report to the Control Room may report to the Control Room prior to pager activation and remain on standby for an event briefing.

If emergency conditions are initially classified as an Alert or higher, and then subsequently reclassified to an Unusual Event, all ERO members should continue to report to their facilities. Although activation of the Technical Support Center, Operational Support Center and Emergency Operations Facility are not required, the ERO staff will be available to assist with event recovery efforts, interface with state emergency response personnel and respond to information requests from the media, elected officials and industry organizations.

Once the initial emergency declaration is made, the associated ER 1.2 checklist for the Short Term Emergency Director (ER 1.2A, B, C or D) shall be implemented at least through to the completion of state notifications prior to terminating the emergency classification or reclassifying the emergency. If the emergency classification is terminated or if reclassification of the emergency is made after completion of the state notifications, the initial NRC notification must still be made within one hour of the initial classification; however, the initial NRC notification will be for the termination of the emergency or for the emergency classification currently in effect (i.e., the reclassification). (Protected: Ref. 6.2)

For an emergency classification that has been terminated or reclassified to a lower emergency classification level prior to the initial NRC notification, the initial NRC notification shall include the following:

- State that a higher emergency classification level had existed prior to the initial notification.
- Explain the conditions that required the higher emergency classification level; and
- Explain the conditions that warranted termination of the emergency classification or reclassification to a lower emergency classification level. (Protected: Ref. 6.2)

Additional discussion for question 100

Question 100 established initial conditions that (1) A Site Area Emergency was declared 37 minutes ago, (2) The Emergency Response plan facilities have NOT been activated and, (3) the conditions no longer meet the Emergency Action Level.

The initial request for a regrade pointed out that the initial conditions created unclear conditions so that no correct answer was available. The crux of this conclusion was the statement that "the Emergency Response plan facilities have not been activated". When the emergency condition was discovered the Shift Manager had assumed the E-plan position of the "Short Term Emergency Director" (STED), but neither the "Station Emergency Director" (SED) nor the "Response Manager" (RM) positions are filled. At this moment in time it is clear that no one is available with the authority to terminate the event until the Technical Support Center (TSC) has activated and a turnover of responsibilities has occurred between the STED and SED, or the Emergency Off-site facilities have activated and the RM has assumed incident command. Appendix "E" of NUREG 1021, part B, item 7, 2nd paragraph states:

> "When answering a question, do *not* make assumptions regarding conditions that are not specified in the question unless they occur as a consequence of other conditions that are stated in the question. For example, you should not assume that any alarm has activated unless the question so states or the alarm is expected to activate as a result of the conditions that are stated in the question. Similarly, you should assume that no operator actions have been taken, unless the stem of the question or the answer choices specifically state otherwise."

No information was provided to the students that allowed them to assume that E-plan activation would successfully occur (i.e.: "no operator actions have been taken"), and their answer should be based on that expected outcome. Instead the question clearly states that emergency condition occurred 37 minutes ago, the Emergency Facilities have NOT been activated, and the condition has cleared. This is the frozen moment that the students felt they should be evaluating.

During the post exam review it was noted that clear direction to process the given emergency plan chain of events is not available in ER 1.2, "Emergency Plan Activation". Section 1.1, "Discussion", provides clarification for responding to other, similar chains of events:

> If an Unusual Event is declared, Primary Responders shall respond per Procedure ER 1.2, Section 5.0, even if notified of the termination of the Unusual Event. (2nd paragraph, section 1.1).
>
> If emergency conditions are initially classified as an Alert or higher, and then subsequently reclassified to an Unusual Event, all ERO members should continue to report to their facilities. (3rd paragraph, section 1.1).

> If the emergency classification is terminated or if reclassification of the emergency is made after completion of the state notifications, the initial NRC notification must still be made within one hour of the initial classification; however, the initial NRC notification will be for the termination of the emergency or for the emergency classification currently in effect (i.e., the reclassification). (3rd paragraph, section 1.1).

These clarifications do provide useful information for the cases stated, but the case presented in the initial question, "An Alert or Higher (i.e. Site Area Emergency) has been declared, but conditions have completely cleared prior to E-plan activation" is not discussed. A procedure change request has been implemented to add the conditions that occurred in this case with the expected response by the station staff to ER 1.2.

There are two other statements made ER 1.2, section 1.1, "Discussion", that further served to create unclear directions for the expected response to the stated conditions:

The 1st sentence of the 4th paragraph states:

> Once the initial emergency declaration is made, the associated ER 1.2 checklist for the Short Term Emergency Director (ER 1.2A, B, C or D) shall be implemented at least through to the completion of state notifications prior to terminating the emergency classification or reclassifying the emergency.

The state notifications are made in step 8 of each respective STED checklist. The turnover of command and control of the emergency does not occur until step 16. The emergency termination is not made until step 17. The direction in section 1.1 states that a reclassification or an event termination could occur any time after step 7 of the checklist.

The 2nd sentence of the third paragraph states:

> Although activation of the Technical Support Center, Operational Support Center and Emergency Operations Facility are not required, the ERO staff will be available to assist with event recovery efforts, interface with state emergency response personnel and respond to information requests from the media, elected officials and industry organizations.

This direction is given for emergency conditions that have been initially classified as an Alert or higher, then subsequently reclassified to an Unusual Event. Because no clear directions that cover the better condition (the event condition has completely cleared), this direction gives the conflicting guidance to consider not activating the Emergency Response Organizations. The procedure change request referenced earlier will also resolve this conflicting guidance issue.

Conclusion:

For the conditions given in the question, the only way to procedurally terminate the event would be to move past the moment in time given as a condition of the question. The question clearly froze a moment in time during E-plan activation and asked the students to determine who could terminate the event at that moment. The current Seabrook procedure provides the conflicting guidance that:

(1) The E-plan can be terminated any time after the state notification is made without continuing to activate the emergency facilities, with a follow up notification to the NRC that the EAL was exceeded, but is now clear. This guidance is incomplete and will be fixed using the Procedure change process

(2) The E-plan can only be terminated by either the SED or the RM, but only after their respective emergency facilities are activated. This condition was not clearly available to the students as a condition of Appendix E of NUREG 1021.

There is no correct answer for the question as written

Technical Reference(s)

ER 1.2, section 1.1 and ER 1.2 SAE Short Term Emergency Checklist

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1.0 OBJECTIVES

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1.1 Discussion

Checklist actions should be performed in the order in which they are listed.

If an Unusual Event is declared, Primary Responders shall respond per Procedure ER 1.2, Section 5.0, even if notified of the termination of the Unusual Event. For an Unusual Event response, on-duty Primary Responders who are directed in Section 5.0 to contact the Control Room shall **not** attempt to call on-duty Operations personnel in the Control Room until their pagers have activated. On-duty Primary Responders who are directed to report to the Control Room may report to the Control Room prior to pager activation and remain on standby for an event briefing.

If emergency conditions are initially classified as an Alert or higher, and then subsequently reclassified to an Unusual Event, all ERO members should continue to report to their facilities. Although activation of the Technical Support Center, Operational Support Center and Emergency Operations Facility are not required, the ERO staff will be available to assist with event recovery efforts, interface with state emergency response personnel and respond to information requests from the media, elected officials and industry organizations.

Once the initial emergency declaration is made, the associated ER 1.2 checklist for the Short Term Emergency Director (ER 1.2A, B, C or D) shall be implemented at least through to the completion of state notifications prior to terminating the emergency classification or reclassifying the emergency. If the emergency classification is terminated or if reclassification of the emergency is made after completion of the state notifications, the initial NRC notification must still be made within one hour of the initial classification; however, the initial NRC notification will be for the termination of the emergency or for the emergency classification currently in effect (i.e., the reclassification). (Protected: Ref. 6.2)

For an emergency classification that has been terminated or reclassified to a lower emergency classification level prior to the initial NRC notification, the initial NRC notification shall include the following:

- State that a higher emergency classification level had existed prior to the initial notification.
- Explain the conditions that required the higher emergency classification level; and
- Explain the conditions that warranted termination of the emergency classification or reclassification to a lower emergency classification level. (Protected: Ref. 6.2)

SITE AREA EMERGENCY CHECKLIST -
SHORT TERM EMERGENCY DIRECTOR
(Continued)

Radioactive material is being released to the environment as indicated by

- **Wide Range Gas Monitor (WRGM) Alert or High Alarm (RM-6528-4)**

OR

- **Main Steam Line Monitor Alert or High Alarm with an Open ASDV or Main Steam Safety Valve on the Affected Main Steam Line**

OR

- **Main Steam Line Monitor Alert or High Alarm and the Steam Driven EFW Pump Operating and Fed from the Affected Line**

OR

- **STED judgment that a radiological release has occurred and been terminated or is continuing**

AND

- **release of material is directly attributable to the event.**

f. Block 6 - Requires authorization signature of the STED or SED

g. Block 7 - Leave blank

8. [] **NOTIFY THE STATES**

a. Give the completed copy of form ER 2.0B to the Work Control Supervisor.

b. Direct the Work Control Supervisor to implement form ER 1.2E.

c. If the Work Control Supervisor is not available, implement form ER 1.2E.

d. Assign the Fire Brigade Leader as Control Room Communicator, and direct the Communicator to implement form ER 1.2F.

e. If notified that the ERO pagers failed to activate, direct the Control Room Communicator to notify a position holder for each Primary Responder position per form ER 1.2F.

SITE AREA EMERGENCY CHECKLIST -
SHORT TERM EMERGENCY DIRECTOR
(Continued)

- Communications with offsite authorities, and
- Status of ERDS activation.

16. [] **COMMAND AND CONTROL TURNOVER (Do not delegate)**

    a. Turn over emergency command and control responsibilities to the Site Emergency Director.

    b. Provide all notification documentation.

    c. Enter the time of turnover: ____________________

    d. Announce turnover of command and control responsibilities in the Control Room

17. [] **EMERGENCY TERMINATION**

A Site Area Emergency cannot be terminated by the STED except as discussed in Precaution 3.5. The emergency shall be terminated by either the Site Emergency Director or the Response Manager.

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NRC Resolution: