PSNH PUBLIC SERVICE
Company of New Hampshire

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July 30, 1984
SBN- 701
T.F. B7.1.2

United States Nuclear Regulatory Commission
Washington, D. C. 20555

Attention: Mr. George W. Knighton, Chief
Licensing Branch No. 3
Division of Licensing

References: (a) Construction Permits CPPR-135 and CPPR-136, Docket Nos. 50-443 and 50-444
(b) USNRC Letter, dated January 12, 1984, "Results of In-Progress Audit of Seabrook Station Detailed Control Room Design Review", G. W. Knighton to R. J. Harrison

Subject: Response to DCRDR In-Progress Audit; SER Outstanding Issue #19; NUREG-0737 Item I.D.1

Dear Sir:

Reference (b) forwarded the results of the "In-Progress Audit of Seabrook Station Control Room Design Review", which was conducted during the period of July 26, 1983 through July 28, 1983 at Seabrook Station by the Human Factors Engineering Branch (HFEB), Division of Human Factors Safety, assisted by consultants from Lawrence Livermore National Laboratory.

Reference (b) indicated that the results of the review thus far indicate that "PSNH is pursuing a course of review which will satisfy the requirements of Supplement 1 to NUREG-0737 except in the areas of system function and task analysis and the subsequent comparison of the results of the analysis with a control room inventory". The systems function and task analysis concern has been posed to other Westinghouse NTOLs and as a result, Westinghouse NTOL and NRC representatives convened on March 29, 1984 to discuss the development of the Emergency Response Guidelines (ERG) and ERG background documentation. The plant specific information requirements stemming from the March 29, 1984 meeting are included in the enclosures to this letter as follows:

- o Part (1): "Response to Disagreements on Methods"
- o Part (1) Attachment 1: "Seabrook Emergency Response Procedure Program"
- o Part (1) Attachment 2: "E-0 Plant Specific"
- o Part (1) Attachment 3: "E-0 Background Document"

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Also enclosed with this letter are the following:

- o Part (2): "Response to Appendices A through D"
- o Part (3): "New HEDs"

The enclosure to this letter contains numerous commitments, (e.g., development of plant specific ERG background documents, control room modifications, additional human engineering review, etc.). As these commitments are completed, you will be formally notified. In light of the commitments we have made herein, we propose that the standing of this item be revised to confirmatory.

Very truly yours,

YANKEE ATOMIC ELECTRIC COMPANY

John DeVincentis

John DeVincentis
Engineering Manager

Enclosure

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1

PART (1)

RESPONSE TO DISAGREEMENTS ON METHODS

(2)

# I. IN-PROGRESS AUDIT RESPONSES

NRC staff reviews of Seabrook reports and the DCRDR in-progress audit at Seabrook Station determined that the Seabrook DCRDR substantially meets the requirements of Supplement 1 of NUREG-0737 and the guidelines of NUREG-0700 with the exception of three areas:

- o The system function and task analysis,
- o The comparison of display and control requirements determined by function and task analysis with a Control Room inventory, and
- o Implementation schedule definitions.

We have reviewed the In-Progress Audit Results as well as our previous submittals on both the DCRDR and EOPs. We have found that much of the information requested by the NRC staff does exist. However, it was not presented in a manner such that the NRC DCRDR team could efficiently review it. We believe that the following clarifications will enable the team to determine that the Seabrook DCRDR meets all the requirements of Supplement 1 to NUREG-0737.

## A. Systems Function and Task Analysis

The staff contends that Seabrook's function and task analysis documentation does not show evidence of a systematic determination of information and control capability requirements (e.g., information parameter type, dynamic range, accuracy, frequency; or control capability type, precision, duration, criticality), which could be objectively compared to the instrumentation available in the Control Room. Information requirements must be based upon the needs of the operator to successfully perform a described task. It appears to the staff, based upon our submittals to them, that these needs were not analyzed before the instrument and control requirements were developed.

There has been a great deal of discussion within the industry and between industry and NRC on this subject in the past year, culminating with meetings between Owners Groups and NRC representatives from both the Procedure Development Group and the Control Room Review Group. This NRC meeting with the Westinghouse Owners Group Procedures Subcommittee was held on March 29, 1984. The purposes of that meeting were (1) for the Subcommittee to discuss how operator information and control needs have been addressed by the Emergency Response Guideline (ERG) development effort, and (2) for the staff to identify any additional analyses or documentation needed for review. A presentation was made by Messrs. McKinney and Surman which included a description of the ERG background documents, development of Revision 1 to the ERG, interactions with the NRC, Supplement 1 to NUREG-0737 requirements, and a detailed discussion in the development of the ERGs and the accompanying background documentation. At this presentation, it was emphasized that one of the main objectives of the ERG is to identify the operator tasks necessary to perform those functions identified in the background documentation.

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At this meeting, the staff made the following comments:

1. Based on the presentations by Mr. McKinney and Mr. Surman, it appears that Revision 1 of the ERG and background documents do provide an adequate basis for generically identifying information and control needs.

2. Each licensee and applicant, on a plant-specific basis, must describe the process for using the generic guidelines and background documentation to identify the characteristics of needed instrumentation and controls. For the information of this type that is not available from the ERG and background documentation, licensees and applicants must describe the process to be used to generate this information (e.g., from transient and accident analyses) to derive instrumentation and control characteristics. This process can be described in either the PGP or DCRDR Program Plan with appropriate cross-referencing.

3. For potentially safety-significant, plant-specific deviations from the ERG instrumentation and controls, each licensee and applicant must provide in the PGP a list of the deviations and their justification. These should be submitted in the plant-specific technical guideline portion of the PGP, along with other technical deviations.

4. For each instrument and control used to implement the Emergency Operating Procedures, there should be an auditable record of how the needed characteristics of the instruments and controls were determined. These needed characteristics should be derived from the information and control needs identified in the background documentation of Revision 1 of the ERG or from plant-specific information.

5. It appears that the Basic version of the ERG and background documentation provide an adequate basis for generically deriving information and control needs. However, because of the differences in the organization of the material in the background documents between Basic and Revision 1, it is apparent that it would be easier to extract the needed information from the Revision 1 background documents.

Based upon the clarification expressed in the above staff comments, we have reviewed both our previous submittals of information to the staff and the results of the staff in-progress audit. From our review, it is apparent to us that the information submitted to the staff does not fully respond to the staff comments resulting from the March 29, 1984 WOG-NRC meeting. We will, therefore, address each meeting comment directly, responding to it here. To aid in this response, we have developed a report describing our plant-specific process for using the generic guidelines and background documentation to identify the characteristics of needed instrumentation and controls. The report is titled, Seabrook Emergency Response Procedure Program, and is attached here.

(4)

Second, it appears that there still exists some misunderstanding on the staff's part of how our Detailed Control Room Design Review was done. We will attempt to clear up those misunderstandings also, by addressing them in detail.

WOG-NRC Meeting Comments

NRC Comment

1. Based on the presentations by Mr. McKinney and Mr. Surman, it appears that Revision 1 of the ERG and background documents do provide an adequate basis for generically identifying information and control needs.

5. It appears that the Basic version of the ERG and background documentation provide an adequate basis for generically deriving information and control needs. However, because of the differences in the organization of the material in the background documents between Basic and Revision 1, it is apparent that it would be easier to extract the needed information from the Revision 1 background documents.

Seabrook Response

Seabrook Station used the Basic version of the ERG and background documentation in developing their Emergency Operating Procedures (EOPs). This Basic version was submitted to you as Westinghouse Owners Group Emergency Response Guidelines, Revision 1, OG-111, dated November 30, 1983.

Since that date, Revision 1 of the ERG and background documents were submitted to you in early May 1984. As described in the attached report, a plant task force has continuously revised, improved, and modified the draft plant-specific ERPs in parallel with and based on the Revision 1 ERGs.

Based upon the two staff comments above, it appears to us that the WOG documents satisfy one part of the staff position - that we do not define operator's information and control needs. These documents do this on a generic basis.

NRC Comment

2. Each licensee and applicant, on a plant-specific basis, must describe the process for using the generic guidelines and background documentation to identify the characteristics of needed instrumentation and controls. For the information of this type that is not available from the ERG and background documentation, licensees and applicants must describe the process to be used to generate this information (e.g., from transient and accident analyses) to derive instrumentation and control characteristics. This process can be described in either the PGP or DCRDR Program Plan with appropriate cross-referencing.

Seabrook Response

On January 17, 1984, Seabrook submitted their Emergency Operating Procedure Package (EOPP) to the NRC, SBN-616. This package describes the process for using generic guidelines and background documentation to identify the characteristics of the needed instrumentation and controls. The process is more completely described in the attached report, Seabrook Emergency Response Procedure Program.

NRC Comment

3. For potentially safety-significant, plant-specific deviations from the ERG instrumentation and controls, each licensee and applicant must provide in the PGP a list of the deviations and their justification. These should be submitted in the plant-specific technical guideline portion of the PGP, along with other technical deviations.

Seabrook Response

This type of information will be developed as described in the attached report.

NRC Comment

4. For each instrument and control used to implement the Emergency Operating Procedures, there should be an auditable record of how the needed characteristics of the instruments and controls were determined. These needed characteristics should be derived from the information and control needs identified in the background documentation of Revision 1 of the ERG or from plant-specific information.

Seabrook Response

This record has been developed, and is available for review at Seabrook Station.

We believe that the above discussion and referenced submittal of information responds to the staff position that the task analysis process used in development of the Seabrook EOPs does not define operator needs with respect to information and control. Operator information and control needs are identified in a manner acceptable to the NRC.

B. The Comparison of Display and Control Requirements Determined by Function and Task Analysis With a Control Room Inventory (Supplement 1 to NUREG-0737, Requirement 3)

The staff states in Section 2.3.3, Control Room Inventory, of the In-Progress Audit Results letter that our process does not satisfy Requirement 3 of Supplement 1 to NUREG-0737 because the function and task analysis, as described in previous Seabrook submittals, did not specify control and display characteristic requirements in sufficient detail to permit comparison with the inventory characteristics. In the previous response on Systems Function and Task Analysis, we further described the analysis and how it was carried out. We believe we have now responded to this conclusion, and have met Requirement 3 of Supplement 1 to NUREG-0737.

C. Clarification of Staff/License Misinterpretation

The second problem with respect to this section on System Function and Task Analysis appears to be a misinterpretation of some of the information provided to you. In an effort to clarify these, we will address the specific statements in the section and point out the misinterpretation.

1. Section 2.3.2, page 7

NRC Statement

"The purposes of the task analysis as described in the revised Seabrook report are:

1. Ab initio procedure preparation.

2. Understanding given procedures when they are not otherwise clear as to goals, functions, and component tasks.

This description does not agree with Requirement 2, which specifies that the purpose of the task analysis is to, 'identify control room operator tasks and information and control requirements during emergency operations.'"

Licensee Response

On page 6 of the revised Seabrook report, we state that "task analyses, procedure talk-throughs and follow-up walk-throughs must be considered as a single inseparable effort." We go on to state that the purpose of the talk-throughs and subsequent walk-throughs was to: "(a) simulate actions by operators in operating, managing and maintaining safe operation of the plant; (b) identify errors stimulated by design inadequacies, and (c) exercise most elements of the Main Control Board that are frequently used, or for which human error probably is considered significant due to high usage or potential impact on plant operation."

If we take task analysis, whose purpose is described in (1) and (2) and talk-throughs and walk-throughs, whose purposes are described in (a), (b) and (c), a single, inseparable effort; then we believe it does agree with Requirement 2 of NUREG-0737, Supplement 1.

2. Section 2.3.2, page 8

NRC Statement

"Questions of task goals and functions for each procedure were discussed and clarified, drawing heavily on the Emergency Response Guideline (ERG) System Review and Task Analysis (SRTA) done by

Westinghouse for the Westinghouse Owners Group (WOG). The task analysis performed by Westinghouse was not described, nor were the objectives of the analysis stated. The specific steps selected for use from the Westinghouse task analysis are not identified. Subsequent staff review of the WOG SRTA indicates that it is a satisfactory start in identifying and describing tasks, but it is generic, not plant specific, and does not identify required information and control capability characteristics sufficiently to compare informational needs to a control room instrumentation and control inventory."

Licensee Response

The Westinghouse task analysis was not described. It has since been submitted, and its use is described in proceeding pages.

3. Section 2.3.2, page 8

NRC Statement

"The second step of the Seabrook task analysis, consisted of talk-throughs of procedures in the simulator. Comments were made by the HF consultants and I&C engineers regarding decision criteria, displays required/available and controls required/available. This process is satisfactory for the verification/validation effort but is an unsystematic approach to defining information and control capability requirements and cannot ensure accuracy or completeness. The analyst is influenced by existing instrumentation rather than defining the characteristics of what is needed by the operator to accomplish the task."

Licensee Response

We feel this has been addressed in our discussion of the use of the Westinghouse documents.

4. Section 2.3.2, page 9

NRC Statement

In step (4) of the NUREG-0700 guideline, the task analysis is performed to establish what instrumentation, controls, and equipment the operator needs for action and decision making. In the Seabrook report, no attempt was made to establish the input and output information and resulting control and display requirements, because the controls and displays already existed in the control room.

Licensee Response

We believe this has now been addressed in our discussion of the use of the Westinghouse documents.

5. Section 2.3.2, page 9

NRC Statement

The Seabrook report implies that the selection and location of Main Control Board (MCB) components, using systems design and detailed design review processes, resulted in an HED-free design which obviated the need to use the methodology of systems function and task analysis as recommended by NUREG-0700 to determine instrumentation and control requirements.

Licensee Response

It is not the intent of our report to imply that a task analysis is not needed. It should be clear from the report and the results that a task analysis was done.

The discussion referenced here, dealing with the original design process, was only to point out that the original design process included many of the steps recommended for a Human Factors Review. Experienced operators were used in the design and review; a full-scale mock-up was developed, reviewed and changed; and a full scale simulator was designed, reviewed, and again changed to provide easier, more effective operation. We wished only to point out that, although a Human Factors specialist was not used in this design process, many experienced operators were. The design, mock-up and simulator reviews and changes could not help but find many HEDs; and these were corrected.

We did not call the process a substitute for a task analysis.

D. Implementation Schedule Definitions

We agree to the implementation schedule as defined by the staff.

- Schedule A, B - Complete prior to fuel load.
- Schedule C - Complete prior to start-up after first refueling outage.
- Schedule E - No corrective action is necessary.

E. Work in Progress

The following reviews are presently in progress. Any identified HEDs resulting from the work will be reported to the NRC at least 120 days PTLF. The discrepancies will be corrected on a schedule approved by the NRC.

- o Radiation Monitoring System
- o Lighting
- o Control Room Administrative Procedures

Two items will not be completely reviewed until after commercial operation. They are:

- o Auditory signals and acoustic noise
- o Heating, Ventilation, and Air Conditioning

Two studies are being completed.

They will be submitted in the near future.

- o Tabulation of colors
- o Tabulation of lights and in control room indicators

We trust that the information provided above responds adequately to and resolves the NRC concerns expressed in the In-Progress Audit Report. If more information is needed, or if a meeting is necessary to discuss any resolution, we are ready to provide such information or meet with you at your convenience.

(10)

Part (1)
Attachment 1

ATTACHMENT 1

- REPORT -

SEABROOK EMERGENCY RESPONSE
PROCEDURE PROGRAM

Since the WOG BASIC ERG set was issued, the Seabrook Station staff has been developing plant-specific Emergency Response Procedures (ERPs) in concert with the WOG effort. The plant staff has actively participated in the WOG ERG program including attendance at all ERG Seminars by station staff operations and engineering personnel involved in ERP development. The Seabrook Operations Manager is a permanent Procedures Subcommittee member.

The first draft plant-specific ERPs were generated under the direction of senior plant operating personnel who were most familiar with plant-specific systems and had previous nuclear power plant operating experience. These ERPs were based on the WOG HP BASIC set with appropriate modifications for plant-specific use. These draft procedures were used for the DCRDR.

Since that time, a number of significant milestones have been passed in the evolution of Seabrook ERPs. These include the following:

- o The Plant Operations Manager appointed a dedicated task group consisting of SRO level operations personnel to follow the WOG Revision 1 ERG program. This task group established interfaces with Yankee Atomic Electric Company Engineering and Analysis Groups to establish the expertise necessary at the plant level to generate Revision 1 based, plant-specific ERPs.

- o The plant ERP task group has identified plant-specific instrumentation requirements to properly execute the ERP tasks. For the instrumentation required, but not originally provided, the ERP task group has been working with Yankee Atomic Electric Company since 1982 to establish specific instrumentation design requirements to include qualification, range, accuracy, display, etc. The new ERP-based instrumentation package includes post-accident qualified, redundant train systems to provide both hard wired indications and SPDS graphic display inputs for the following variables:

  a) RCS subcooling based on average core exit temperature,

  b) RCS pressure with transmitters located outside containment,

  c) Average core exit temperature based on average of twenty-seven incore TCs per train,

  d) Reactor vessel collapsed level,

  e) Reactor vessel dynamic head,

  f) Wide-range neutron flux (fission chamber based power)

  g) Wide-range neutron flux rate, and

  h) Shutdown monitor

  This new instrumentation, when combined with the existing qualified instrumentation and display capabilities, provides the information necessary to complete ERP tasks and to monitor all critical safety functions.

- o The plant ERP task group has continuously revised, improved and modified the draft plant-specific ERPs in parallel with and based on the Revision 1 ERGs.

- o In October of 1983, the WOG conducted the Revision 1 ERG Validation Program at Seabrook Station using the Revision 1 based plant-specific ERPs. It was evident that these procedures were effective in mitigating a broad range of complex emergency transients. The instrument and controls needed to execute the procedure tasks were verified to be adequate.

- o Since the Revision 1 ERG Validation Program, the ERP task team has been involved in resolving comments generated during the program, most of which were plant-specific in nature.

In December of 1983, the WOG began issuance of Revision 1 ERG background documents. Prior to this time, the ERP task team had made the decision to write plant-specific background documents. At the time, the decision was based on the usefulness of the documents for operator training and the preservation of the research and analytical work used to write the plant-specific ERPs. The plant-specific background documents would also include the following information.

- o Documentation of all setpoints, values and control characteristics required for the plant-specific ERPs. This documentation, called the ERP Setpoint and Value Study, also contains data regarding instrument and control usage, instrument accuracy, error analysis, required ranges, applicable calculations, and informational source references.

- o Operator task analysis.

- o Identification of plant-specific deviations from the generic WOG ERGs. By the nature of the plant-specific background documents, all instrumentation, control and strategy deviations are identified by comparison with the Revision 1 ERG Background Documents. Since there are many technical deviations, the ERP task team strongly opposed a special document that only identifies "significant" deviations because it is extremely subjective.

- o Safety analysis is included and will delete all generic, non-plant-specific information. Where the generic analysis is non-applicable or insufficient, a plant-specific analysis will be substituted.

The plant-specific background document generation effort is the last phase of the plant-specific PGP project and parallels the WOG Revision 1 evolution.

The plant-specific background document generation effort at Seabrook has just begun, having just received the WOG Revision 1 generic documents. The plant-specific documents will use the WOG format and will be available for review and audit when completed.

The plant ERP task team is completing the plant-specific background document for E-0. A draft copy is provided in this transmittal for your use. We trust that this portion of our PGP effort provides the documentation necessary to show evidence of a systematic determination of all information and control capability necessary to accomplish procedural tasks. Background documents,

(13)

like the E-0 draft provided, will be prepared for all plant-specific ERPs. We expect this effort to be complete by June 1, 1985.

Since we know that our ERPs are effective in mitigating accidents, based on the ERG Validation Program, we expect that the NRC DCRDR team open items would be placed in a confirmatory status pending completion of our plant-specific background documents.

14

Part (4)
Attachment 2

E - O

PLANT SPECIFIC

Part(1)
Attachment 3

E - O

BACKGROUND DOCUMENT

# E-0 BACKGROUND DOCUMENT

NOTE: The detailed plant-specific background document contains documentation regarding plant-specific setpoints and values along with supporting calculations and analysis. In cases when a setpoint or value is used more than once, the supporting documentation is provided with the first procedural usage. Plant-specific descriptive information and departure from the generic ERG is discussed where appropriate.

NOTE: Steps 1 through 14 are IMMEDIATE ACTION steps.

PURPOSE: To remind the operator that the first 14 steps are immediate actions

BASIS:

Immediate actions are those actions which the operator should be able to perform before opening and reading his emergency procedures. In general, immediate actions are limited to the verification of automatic protection features of the plant. Although the immediate actions should be memorized by the operator, they need not be memorized verbatim. The operator should know them well enough to complete the intent of each step, which is to verify that the automatic actions have occurred. The order in which they should be performed should also be consistent with the step sequence requirements, i.e., the order of the first four steps is important and the rest may be interchanged.

ACTIONS:

N/A

INSTRUMENTATION:

N/A

CONTROL/EQUIPMENT:

N/A

KNOWLEDGE:

The intent of the immediate action steps should be committed to memory

PLANT-SPECIFIC INFORMATION:

N/A

NOTE: Initiate monitoring of critical safety function status trees at Step 27 OR if exiting from this procedure.

PURPOSE: To remind the operator that the rules of usage direct that status tree monitoring begin as directed in E-0 (Step 27) or when exiting E-0 to another ERP.

BASIS:

The immediate actions and subsequent diagnostic steps in E-0 must be completed to ensure that protection and safeguards systems are operating or have operated. Therefore, critical safety function status trees are not formally monitored until immediate action checks, verifications and initial diagnostics are complete.

ACTIONS:

N/A

INSTRUMENTATION:

N/A

CONTROL/EQUIPMENT:

N/A

KNOWLEDGE:

N/A

PLANT-SPECIFIC INFORMATION:

N/A

NOTE: Review OPERATOR ACTION SUMMARY periodically.

PURPOSE: To remind the operator to review the operator action summary for the E-0 series of procedures.

BASIS:

The operator action summary provides a list of important items that should be continuously monitored. If any of the parameters exceed their limits, the appropriate operations should be initiated. Key cautions that apply to multiple steps or the entire procedure are listed. The operator action summary appears on the back side of each procedure page so that is is always visible to the control room command operator.

ACTIONS:

N/A

INSTRUMENTATION:

N/A

CONTROL/EQUIPMENT:

N/A

KNOWLEDGE:

Since each operator action summary page for a particular procedure is potentially unique, the operator should know what items comprise each summary. Periodic review of the summary page while the procedure is in effect provides assurance that the command operator will direct the proper response. Operators are not required to memorize items since this step requires that items be reviewed.

PLANT-SPECIFIC INFORMATION:

N/A

## STEP DESCRIPTION TABLE FOR E-0 STEP 1

**STEP:** Verify Reactor Trip

**PURPOSE:** To ensure that the reactor has tripped

**BASIS:**

Reactor trip must be verified to ensure that the only heat being added to the RCS is from decay heat and reactor coolant pump heat. The safeguards systems that protect the plant during accidents are designed assuming that only decay heat and pump heat are being added to the RCS. If the reactor cannot be tripped, a transition is made to FR-S.1, RESPONSE TO NUCLEAR POWER GENERATION/ATWS, to deal with ATWS conditions.

**ACTIONS:**

- o Determine if the reactor has tripped
- o Determine if the reactor will not trip
- o Trip the reactor
- o Transfer to FR-S.1, RESPONSE TO NUCLEAR POWER GENERATION/ATWS, step 1

**INSTRUMENTATION:**

- o Control rod bottom lights lit indicate that the associated control rod is fully inserted. Each control and shutdown rod has its own rod bottom light.

- o Reactor trip and bypass breaker position is indicated by position lights.

- o Neutron flux decreasing can be verified by any of the following indicators:
  1) Power range flux in percent (0-120%)
  2) Intermediate range flux in amps ($10^{-11}$ - $10^{-3}$
  3) Source range flux in counts per second ($10^0$ - $10^6$)
  4) Neutron flux recorder (NR-45) which covers all ranges of neutron flux

- o Post Accident Neutron Flux (Fission Chamber) in range of $10^{-8}$% - 2 X $10^{-2}$ power for each redundant train.

- o Post Accident Neutron Flux Rate (Fission Chamber) in range of (-)1 - (+)7 DPM in each redundant train.

**CONTROL/EQUIPMENT:**

Redundant switches for manual reactor trip, (each switch trips both trains).

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KNOWLEDGE:

N/A

PLANT-SPECIFIC INFORMATION:

The manual reactor trip switches deenergize the undervoltage trip coils and energize the shunt trip coils.

The verification of reactor trip will normally be accomplished using the Westinghouse supplied DRPI and nuclear instruments. The post-accident nuclear instruments are used to detect loss of core shutdown during the accident and subsequent recovery actions. These instruments are also used to feed the critical safety function status trees.

**STEP:** Verify Turbine Trip

**PURPOSE:** To ensure that the turbine is tripped

**BASIS:**

The turbine is tripped to prevent an uncontrolled cooldown of the RCS due to steam flow that the turbine would require.

**ACTIONS:**

- o Determine if all turbine stop valves are closed
- o Trip the turbine

**INSTRUMENTATION:**

Turbine stop valve position indication for each stop valve

**CONTROL/EQUIPMENT:**

- o Turbine trip pushbutton
- o Main steamline isolation valve (MSIV) switches
- o Generator breaker switch

**KNOWLEDGE:**

N/A

**PLANT-SPECIFIC INFORMATION:**

N/A

STEP: Verify Power To AC Emergency Busses

PURPOSE: To ensure electrical power to at least one emergency bus

BASIS:

AC power must be verified from either offsite sources or the diesel generators to ensure adequate power sources to operate the safeguards equipment. At least one train of safeguards equipment is required to deal with emergency conditions. If at least one train is not available, the operator should try to quickly restore one train, e.g., start a diesel generator and load it on the emergency bus. If at least one train cannot be restored quickly, the operator should transfer to ECA-0.0, LOSS OF ALL AC POWER.

It is also desirable to have power to all ac emergency busses. If power is available to only one train, the operator should initiate attempts to restore power to the other train while continuing with the next step in the procedure to deal with the emergency condition.

ACTIONS:

- o Determine if at least one ac emergency bus is energized
- o Determine if power cannot be restored to at least one ac emergency bus
- o Determine if all ac emergency busses are energized
- o Try to restore power to at least one ac emergency bus
- o Transfer to ECA-0.0, LOSS OF ALL AC POWER, step 1
- o Try to restore power to deenergized ac emergency busses

INSTRUMENTATION:

Voltage indication for each 4160 VAC emergency bus

CONTROL/EQUIPMENT:

Controls for starting and loading diesel generators

KNOWLEDGE:

N/A

PLANT-SPECIFIC INFORMATION:

Emergency bus voltage indication is provided for each bus. Normal voltage is 4160 VAC. Indicators are scaled 0-5000 VAC.

Power for the emergency busses and non-emergency busses is not normally dependent on a fast transfer feature subsequent to the turbine trip. Since the generator breaker is upstream of the normal Unit Auxiliary Transformer (UAT) feed, power simply reverses and backfeeds through the Generator Stepup Transformer (GSU) to the plant busses, hence there is no requirement for a fast transfer to another offsite source.

If the UAT or GSU fails, a fast transfer will occur which switches to the Reserve Auxiliary Transformer (RAT). This transfer is dependent on multiple breaker operation and could result in one or more dead plant busses should a breaker fail to operate properly.

See attached sheet.

## SEABROOK STATION

### Setpoint and Value Study Documentation Sheet

**Setpoint/Value Description:** Bus E5 & E6 Voltage

**Determined Setpoint/Value:** 0-5000 ± 100V Scale Grad 100V

**Specific Instrument Usage:** EDE-VM-9708, 9718
VTR 0.5% Accuracy

**References/Sources:** 3, F.P. 31123, 5KV Switchgear Instruction Manual

**Assumptions:**

**Calculations:**

PT Accuracy = ±1% (Enveloping)

VTR Accuracy = ±0.5%

Indicator Accuracy = ±2%

$$\text{Error in \% Span} = \pm\sqrt{(1)^2 + (0.5)^2 + (2)^2}$$

$$= \pm\sqrt{1 + .25 + 4} = \pm 2.3\%$$

$$\text{Error} = 5000 \times \pm 2.3\%$$

$$= \pm 115V \sim \pm 100V$$

STEP: Check If SI Is Actuated

PURPOSE: To determine if SI is in service or is required

BASIS:

The operator should check if SI is actuated or if only a reactor trip has occurred. He should also evaluate if an SI is required but has not occurred.

ACTIONS:

- o Determine if SI is actuated
- o Determine if SI is required
- o Actuate SI
- o Transfer to ES-0.1, REACTOR TRIP RESPONSE, step 1

INSTRUMENTATION:

- o SI actuation status lights
- o SI actuation annunciator lights for Train A and Train B

CONTROL/EQUIPMENT:

Two manual SI actuation switches, each of which actuates both trains of SI

KNOWLEDGE:

Conditions requiring SI actuation

PLANT-SPECIFIC INFORMATION:

If only one train of SI is actuated, the operator is instructed to manually actuate SI to establish full ECCS actuation

STEP: Verify FW Isolation

PURPOSE: To ensure feedwater isolation has occurred

BASIS:

The main feedwater system is isolated on a FW Isolation signal to prevent uncontrolled filling of any steam generator and the associated excessive RCS cooldown which could aggravate the transient, especially if it were a steamline break. The main feedwater pump turbines are tripped if running since they continue to demand steam for minimum flow recirculation.

ACTIONS:

- o Determine if the following valves are closed:
  - Main FW flow control valves
  - Main FW flow control bypass valves
  - Main FW isolation valves
- o Close valves as necessary
- o Verify main FW pump turbines tripped
- o Verify main FW pump discharge valves closed

INSTRUMENTATION:

Position indications for:
- o Main FW flow control valves
- o Main FW flow control bypass valves
- o Main FW isolation valves
- o Main FW pump discharge valves

CONTROL/EQUIPMENT:

Switches for:
- o Main FW flow control valves
- o Main FW flow control bypass valves
- o Main FW isolation valves
- o Main FW pump turbine
- o Main FW pump discharge valves

KNOWLEDGE:

N/A

PLANT-SPECIFIC INFORMATION:

Main feedwater isolation should occur automatically after a reactor trip (P-4) in conjunction with a low $T_{AVG}$ condition (564°F). The combination of P-4 and low $T_{AVG}$ closes the following:

- o Main FW flow control valves (regulating valves)
- o Main FW flow control bypass valves (regulating valve bypass valves)
- o Main FW isolation valves

With an SI signal present, the above automatic actions should automatically occur plus the following:

- o Main FW pump turbines trip
- o Main FW pump discharge valves close
- o Startup feed pump auto start is blocked

At Seabrook, SG blowdown isolation occurs nytime the emergency feedwater (EFW) pumps get an auto start signal. Any of the following signals cause EFW pump startup:

- o SI
- o Low Low SG Level in any SG
- o Loss of Power
- o Manual Demand

In addition, a Phase A isolation will also terminate SG blowdown and is verified in Step 6. SG sample isolation occurs when SG blowdown is terminated.

STEP: Verify Containment Isolation Phase A Actuation

PURPOSE: To ensure non-essential containment penetrations are isolated and to verify Phase A actuated equipment is aligned.

BASIS:

The non-essential containment penetrations are isolated to prevent potential release of radioactive materials from containment and other supporting equipment is aligned as required by design.

ACTIONS:

- o Determine if Containment Isolation Phase A is actuated
- o Determine if Containment Isolation Phase A valves are closed
- o Actuate Phase A
- o Close Phase A valves as necessary
- o Align Phase A actuated equipment as necessary

INSTRUMENTATION:

- o Containment Isolation annunciator
- o Containment Isolation Phase A valves position status lights
- o Containment Isolation Phase A valve position lights
- o Containment Isolation Phase A equipment status lights

CONTROL/EQUIPMENT:

Switches for:
- o Containment Isolation Phase A actuation for each train
- o Containment Isolation Phase A valves
- o Containment Isolation Phase A ('T' signal) actuated equipment

KNOWLEDGE:

N/A

PLANT-SPECIFIC INFORMATION:

Phase A status panels, one for each train, are provided so that the operator can determine at a glance whether any Phase A actuated device is not in its proper position or status. The status panels are designed so that all status lights are lit when all Phase A actuated equipment is aligned. Any unlit device would indicate that the associated device is NOT in its correct alignment. The operator would then manually align the device as necessary.

STEP DESCRIPTION TABLE FOR E-0 STEP 7

STEP: Verify EFW Pumps Running

PURPOSE: To ensure EFW pumps are running

BASIS:

Both EFW pumps (one motor driven and one turbine driven) start automatically on an SI signal to provide feed to the SGs for decay heat removal.

ACTIONS:

- o Determine if MD EFW pump is running
- o Determine if the turbine-driven pump is running
- o Start EFW pumps if necessary
- o Open turbine-driven pump steam supply valves if necessary
- o Check that the turbine-driven pump trip valve is open

INSTRUMENTATION:

- o MD EFW pump status indication lights
- o Turbine-driven EFW pump steam supply valve position indication lights
- o Turbine-driven EFW pump trip valve position indication light

CONTROL/EQUIPMENT:

Switches for:
- o MD EFW pump
- o Turbine-driven EFW pump steam supply valves, MS-V127 and MS-V128

KNOWLEDGE:

N/A

PLANT-SPECIFIC INFORMATION:

Both EFW pumps (motor driven and turbine driven) start on any of the following conditions:

- o SI actuation
- o Any SG level $\leq$ 18.1% NR (Low Low SG Level setpoint)
- o Loss of AC power
- o Manual demand

STEP: Verify ECCS Pumps Running

PURPOSE: To ensure ECCS pumps are running

BASIS:

ECCS provides makeup inventory to the RCS for cooling of the core during accident conditions. Since SI is actuated, all ECCS pumps have a start signal and the operator should verify that they are running.

ACTIONS:

- o Determine if the following pumps are running:
  - Centrifugal charging pumps (CCPs)
  - Safety injection pumps (SIPs)
  - Residual heat removal pumps (RHRs)
- o Start pumps if necessary

INSTRUMENTATION:

Status indications for:
- o CCPs
- o SI pumps
- o RHR pumps

CONTROL/EQUIPMENT:

Switches for:
- o CCPs
- o SI pumps
- o RHR pumps

KNOWLEDGE:

N/A

PLANT-SPECIFIC INFORMATION:

N/A

STEP: Verify PCCW Pumps - RUNNING

PURPOSE: To ensure that at least one PCCW pump in each train associated PCCW loop is running and that at least one thermal barrier cooling pump is running

BASIS:

PCCW pumps provide cooling to certain safeguards components and the reactor coolant pump thermal barrier cooling system

ACTIONS:

- o Determine if PCCW pumps are running - at least one pump per loop
- o Start PCCW pumps if necessary
- o Determine if at least one thermal barrier cooling pump is running

INSTRUMENTATION:

PCCW pumps status lights
Thermal barrier cooling pump status lights

CONTROL/EQUIPMENT:

Switches for PCCS pumps
Switches for thermal barrier cooling pumps

KNOWLEDGE:

N/A

PLANT-SPECIFIC INFORMATION:

The thermal barrier cooling system consists of a dedicated closed cooling loop exclusively for the reactor coolant pump thermal barriers. This cooling loop can be cooled by either or both Train A or B PCCW loops. All thermal barrier cooling system components are located inside containment. This system maintains thermal barrier cooling to all four RCP thermal barriers should either PCCW loop become disabled and is a backup RCP seal cooling mechanism should RCP seal injection flow be reduced or lost.

STEP DESCRIPTION TABLE FOR E-0 STEP 10

STEP: Verify Ultimate Heat Sink Operation

PURPOSE: To ensure that either the Atlantic Ocean or the cooling tower can accept the PCCW and the emergency diesel generator heat loads

BASIS:

Service water pumps or cooling tower pumps and fans provide cooling to the emergency diesel generator cooling system (DCCW) and each PCCW system

ACTIONS:

- Determine if service water pumps are running - at least one per train
- Start service water pumps - at least one per train

- OR -

- Determine if cooling tower pump and fan are running in train
- Start cooling tower pump and fan in train

INSTRUMENTATION:

- Service water pump status lights
- Cooling tower pump status light
- Cooling tower fan status light

CONTROL/EQUIPMENT:

- Switches for service water pumps in each train
- Switches for cooling tower pumps, one in each train
- Switches for cooling tower fan(s) in each train
- Tower actuation switch for each train

KNOWLEDGE:

N/A

PLANT-SPECIFIC INFORMATION:

Either one service water pump or one cooling tower pump and cooling tower fan in the TA mode in each train must be operating to establish an adequate heat sink.

STEP: Verify SW Cooling to DGCW

PURPOSE: To ensure that the emergency diesel-generators have adequate cooling

BASIS:

Diesel-generator cooling is essential since the units automatically start on an SI signal, regardless of whether a loss of power has occurred.

ACTIONS:

- o Determine if the service water (SW) flow isolation valve opens upon diesel-generator start for each train
- o Verify service water (SW) flow is indicated for each train - GREATER THAN 1700 GPM

INSTRUMENTATION:

- o SW valve position status light for each train
- o SW flow indicator for each train

CONTROL/EQUIPMENT:

Switch for SW isolation valve in each train

KNOWLEDGE:

N/A

PLANT-SPECIFIC INFORMATION:

SW flow indicators to each diesel-generator are 0-2500 GPM. Normal flow is approximately 1800 GPM. See attached sheet.

This step represents a departure from the generic plant in that the Containment Fan Coolers at Seabrook are not required to limit containment pressure, temperature or humidity during accident conditions. No credit is taken in the safety analysis for these fans, however they will remain operating until Phase B isolation occurs or a Loss of Power with SI condition exists. Since five of the six Containment Fan Coolers are normally run continuously, no action step in E-0 is necessary. If containment pressure reaches the Phase B isolation setpoint of 18.0 PSIG, the redundant train Containment Building Spray Systems actuate to limit containment pressure and temperature.

Since verification of proper service water (SW) cooling to the diesel-generators is necessary, this step was substituted in lieu of the inapplicable generic ERG step.

## SEABROOK STATION

### Setpoint and Value Study Documentation Sheet

**Setpoint/Value Description:** D/G SW Flow Indication

**Determined Setpoint/Value:** 1700 gpm at 95°F

**Specific Instrument Usage:** SW FI 6181, 6191 (0-2500 gpm), minor grad. 100 gpm

**References/Sources:**

1. RAI 420.48
2. C. R. Tuley, et al., "Westinghouse Setpoint Methodology for Protection and Control Systems-Seabrook Station", November 1982

**Assumptions:**

Flow required = 1800 gpm at 95°F
Error = ± 3. % based on ± 2% (actual ± 1%)

**Calculations:**

Minimum required for operation on cooling tower

Round down due to

Min. Flow = 1800 - 62 = 1738 Round to 1700 gpm

NOTE: Lower flows permissable at colder temp or less than full load

$$\text{Error in GPM} = 1800 \times \frac{3.6\%}{2 \times 100} \times \left(\frac{2500}{1800}\right)^2$$

$$= 62 \text{ gpm}$$

(62)

**STEP:** Verify Containment Enclosure Cooling and Exhaust

**PURPOSE:** To ensure design environmental conditions are maintained for safeguards equipment and to check that a negative containment enclosure pressure is established

**BASIS:**

Containment enclosure cooling ensures long term operating capability for safeguards equipment. The containment enclosure exhaust function provides assurance that any containment leakage or airborne leakage from safeguards equipment is filtered before it is discharged to the plant vent.

**ACTIONS:**

- Determine if at least one containment enclosure cooling unit is operating
- Start cooling unit if necessary
- Determine if containment enclosure pressure is negative
- Adjust enclosure pressure as necessary

**INSTRUMENTATION:**

- Status lights for containment enclosure cooling system fans and damper position
- Status lights for containment enclosure exhaust fans and damper position
- Containment enclosure negative pressure indication

**CONTROL/EQUIPMENT:**

Switches for:

- Containment enclosure supply fans
- Containment enclosure return fans
- Containment enclosure exhaust fans
- Remote operated dampers

**KNOWLEDGE:**

N/A

PLANT-SPECIFIC INFORMATION:

The containment enclosure cooling system is designed to operate under both normal and emergency operating conditions and maintain the design environment to the following areas:

- o Charging pump areas
- o Safety injection equipment vault areas
- o Residual heat removal equipment vault areas
- o Containment spray heat exchanger equipment areas
- o Mechanical penetration area
- o Electrical penetration area

Normally, one of the redundant train containment enclosure cooling systems is in operation to maintain space temperatures of less than 104°F. In emergency conditions, the system maintains space temperatures less than 148°F under the most severe conditions.

The containment enclosure emergency exhaust filter system is designed to operate following a LOCA to maintain the containment enclosure equipment area; containment enclosure annulus; electrical penetration area; mechanical penetration area; RHR and SI equipment vaults; and the charging pump areas at a negative pressure with respect to the outdoor and adjacent ambient atmospheric pressure and to filter the exhaust from these areas prior to discharge to the atmosphere via the plant unit vent. The exhaust system contains redundant filter units with fans, dampers and controls necessary to operate the system. The purge line from the containment combustible gas control system is piped to the exhaust filter unit(s).

The capacity of each fan in the exhaust filter system is 2000 CFM. The calculated in-leakage into the containment enclosure annulus; containment enclosure equipment area; electrical penetraton area; mechanical penetration area; RHR and SI equipment vaults and the charging pump areas varies from 0 CFM to 1000 CFM as the differential pressure in the area varies from 0" to 0.25" W.C., negative. This in-leakage rate results in a minimum fan exhaust capacity of 1000 CFM available for reduction of pressure. On this basis of net exhaust capacity, the required time to produce 0.25" W.C. negative pressure in the areas will be approximately (3.5) minutes or less which is considered to be acceptable. Based on this time delay, this step is appropriately placed at the latter portion of the E-0 immediate actions.

This step represents a deviation from the generic ERG. At Seabrook, containment ventilation (purge) isolation is verified in Step 6, since the purge isolation valves close due to Phase A containment isolation.

STEP: Check If Main Steamlines Should Be Isolated

PURPOSE: To ensure main steamlines are isolated when required

BASIS:

Main steamlines are isolated, when certain setpoints are reached, to either minimize the consequences of and/or terminate the mass and energy releases associated with a high energy secondary line break.

ACTIONS:

- Determine if main steamlines should be isolated
- Determine if main steamline isolation and bypass valves are closed
- Close valves if necessary

INSTRUMENTATION:

- Main steamline pressure for each steamline
- Containment building pressure
- Main steamline isolation valve position lights
- Main steamline isolation valve bypass valve position lights

CONTROL/EQUIPMENT:

Switches for main steamline isolation and bypass valves

KNOWLEDGE:

N/A

PLANT-SPECIFIC INFORMATION:

Main steamline isolation should occur automatically if any of the following conditions exist:

- o Low steamline pressure, ≤ 585 PSIG, in any main steamline above P-11 setpoint of 1950 PSIG
- o Main steamline pressure negative rate of 100 PSI with a 50 second T, below P-11 SI block
- o Containment pressure of ≥ 4.3 PSIG (HI-2)

Main steamline pressure indications are described below:

- o Main steamline pressure indicators for each SG, 0-1300 PSIG
- o Main steamline pressure recorders for each SG, 0-1300 PSIG
- o Bistable lights for low main steamline pressure isolation
- o Bistable lights for high steamline negative rate isolation

Containment building pressure indications are described below:

- o Containment pressure indicators, 0-60 PSIG for each train
- o Containment pressure recorder, 0-60 PSIG
- o Containment pressure bistable lights for main steamline isolation

See attached sheets.

SEABROOK STATION

Setpoint and Value Study Documentation Sheet

Setpoint/Value Description: Low steam line pressure safety injection actuation setpoint.

Determined Setpoint/Value: 585 psig.

Specific Instrument Usage: MS-PI-516; MS-PI-526; MS-PI-536; MS-PI-546

References/Sources:

1. C. R. Tuley, et al., "Westinghouse Setpoint Methodology for Protection and Control Systems - Seabrook Station", W Proprietary, November 1982.

2. "Precautions, Limitations and Setpoints for Seabrook Station", NAH-U-2781, May 9, 1983.

3. V. M. Thomas, "Setpoint Study for PSNH - Seabrook Station Units 1 and 2", WCAP-10136, August 1982.

Assumptions: Used in steam line break analysis.

Calculations: See FSAR Section 15.1.5 for analysis.

SEABROOK STATION

Setpoint and Value Study Documentation Sheet

Setpoint/Value Description: Containment Hi-2 Pressure Setpoint

Determined Setpoint/Value: 4.3 psig

Specific Instrument Usage: N/A

References/Sources: SBN-470

Assumptions:

Calculations: N/A

SEABROOK STATION

Setpoint and Value Study Documentation Sheet

**Setpoint/Value Description:** Main steamline pressure negative rate trip (MSIVs)

**Determined Setpoint/Value:** - 100 PSI with a 50 second time constant

**Specific Instrument Usage:** Bistable status light

**References/Sources:** C. R. Tuley, et al., "Westinghouse Setpoint Methodology for Protection and Control Systems - Seabrook Station", November 1982

**Assumptions:**

**Calculations:** N/A

STEP DESCRIPTION TABLE FOR E-0 STEP 14

STEP: Check Containment Pressure - HAS REMAINED LESS THAN 18 PSIG BY PRESSURE RECORDING

PURPOSE: To ensure automatic actuation of containment spray and Containment Isolation Phase B if containment pressure exceeded 18 psig

BASIS:

If containment pressure exceeds 18 psig, containment spray is automatically initiated to mitigate the containment pressure transient. Containment Isolation Phase B valves are closed to isolate additional potential release paths from containment. Since component cooling to the RCP thermal barrier heat exchangers and motors is isolated on a Phase B signal, the RCPs are tripped to preclude overheating of the seals and motors.

The basis for the "has remained less than 18 psig" condition on containment pressure is that containment pressure may have exceeded the setpoint and then decreased due to spray actuation. In this case the operator should still verify system operation as per the Response Not Obtained (RNO) column, and trip the RCPs.

ACTIONS:

o Determine if containment pressure has remained less 18 psig by chart recorder
o Determine if containment spray initiated
o Determine if Containment Isolation Phase B valves and equipment aligned
o Manually initiate containment spray if necessary
o Manually position Phase B valves and align equipment if necessary
o Stop all RCPs

INSTRUMENTATION:

o Containment pressure indication - RECORDER
o Containment spray pumps status lights
o Containment Isolation Phase B valves position indication lights
o RCPs status lights
o Containment spray pump discharge pressure
o Containment spray pump miniflow valve position indication lights
o Spray additive tank outlet valve position indication lights

CONTROL/EQUIPMENT:

Switches for:
- o Containment spray initiation
- o Phase B isolation valves
- o RCPs
- o Spray additive tank outlet valves
- o Containment spray pump miniflow valves

KNOWLEDGE:

N/A

PLANT-SPECIFIC INFORMATION:

Containment pressure recorders in the range of 0-60 PSIG and (-)5 - 160 PSIG are provided.

When containment spray actuation occurs, the isolation valves from the spray additive tank (SAT) open to allow NaOH to gravity drain to the RWST mix chamber. At least one of the redundant train associated SAT outlet valves must be open for proper NaOH application.

Since containment spray flow is not directly measured, the operator verifies that the discharge valve to the containment spray header in each train is open and that the containment building spray (CBS) pump pressure in each train is less than shutoff head.

See attached sheets for detailed pump shutoff head value determination.

Although no credit is taken for the operation of the containment structure cooling fan units, they continue to operate until a Phase B isolation occurs. If containment pressure remains below 18.0 PSIG, these units will continue to remove energy from the containment.

If a loss of power has occurred, the containment structure cooling units are not sequenced onto the emergency busses with an SI signal present.

See attached sheets.

SEABROOK STATION

Setpoint and Value Study Documentation Sheet

| | |
|---|---|
| Setpoint/Value Description: | Containment pressure setpoint for isolation phase B and spray actuation (HI-3) |
| Determined Setpoint/Value: | 18 psig |
| Specific Instrument Usage: | PI934; PI935; PI936; PI937<br>PR-934; PR-937 |
| References/Sources: | 1. C. R. Tuley, et al., "Westinghouse Setpoint Methodology for Protection and Control Systems - Seabrook Station," W Proprietary, November 1982.<br>2. "Precautions, Limitations and Setpoints for Seabrook Station," NAH-U-2781, May 9, 1983. |
| Assumptions: | This setpoint (with uncertainties) was used in the containment design evaluation in response to a LOCA and in response to a steam line break |
| Calculations: | See FSAR Section 6.2.1, "Containment Functional Design." |

SEABROOK STATION

Setpoint and Value Study Documentation Sheet

Setpoint/Value Description: The plant-specific value for the shutoff head pressure of the containment spray pumps.

Determined Setpoint/Value: 290 psig at 0 gpm

Specific Instrument Usage: CBS-PI-2313 for Train A range: 0-500 psig
CBS-PI-2315 for Train B graduations: 10 psig

References/Sources: See pump performance curves attached.

Assumptions: Assume NPSHR at 3,010 gpm for pump suction inlet head.

Calculations: At 0 gpm pump shutoff head (from curves) is 700 ft. and NPSHR at 3,010 gpm is 19 ft. Then the discharge head is equal to the sum of the TDH and the suction head (NPSHR).

discharge head = 700 + 19 = 719 ft.

Convert discharge head to pressure

discharge pressure = (discharge head) ÷ (2.31)

therefore, discharge pressure = $\frac{719}{2.31}$ = 311 psig

Error = $\pm$ 3%

Pressure Error = range x $\pm$ 0.03
= 500 psi x $\pm$ 0.03
= $\pm$ 15 psig

Lowest Shutoff Pressure = 311 - 15 psig = 296 psig

Round to 290 psig (scale graduation 10 psig)

SEABROOK STATION

Setpoint and Value Study Documentation Sheet

| | |
|---|---|
| Setpoint/Value Description: | The plant-specific containment spray pump discharge head corresponding to the containment spray system flow at design conditions. |
| Determined Setpoint/Value: | 242 psig |
| Specific Instrument Usage: | CBS-PI-2313 for Train A range: 0-500 psig<br>CBS-PI-2315 for Train B graduations: 10 psig |
| References/Sources: | See pump performance curves attached. |
| Assumptions: | Assume NPSHR at 3,010 gpm for pump suction inlet head. |
| Calculations: | At 3010 gpm the TDH (from curves) is 540 ft. and NPSHR at 3010 gpm is 19 ft. Then the discharge head is equal to the sum of the TDH and the suction head (NPSHR). |

discharge head = 540 + 19 = 559 ft.

Convert discharge head to pressure

discharge pressure = (discharge head) ÷ (2.31)

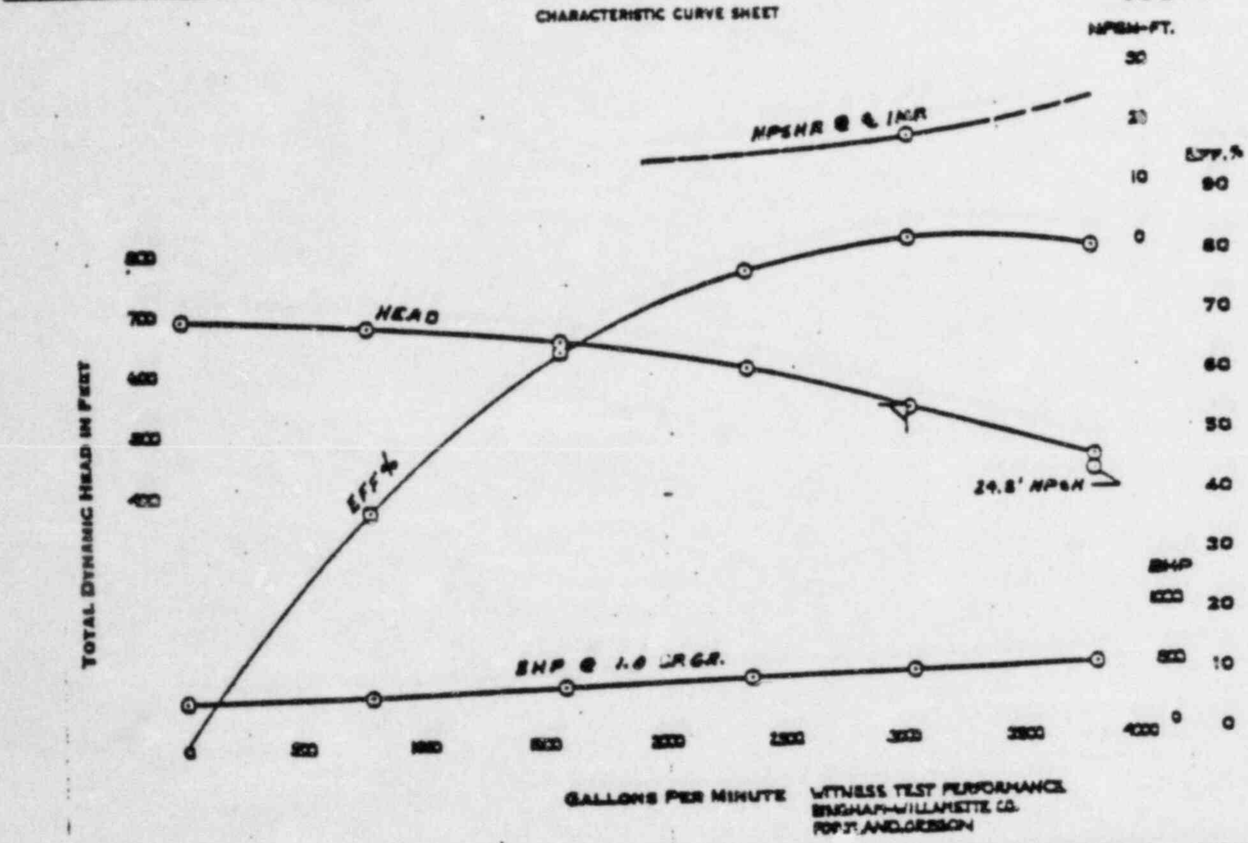
therefore, discharge pressure =

(559) ÷ (2.31) = 242 psig

1-CBS-P-9A

35374

CHARACTERISTIC CURVE SHEET




| | | | | | |
|---|---|---|---|---|---|
| UNITED ENGRG. & CONSTRUCT. INC.<br>PUB. SERVICE CO. NEW HAMPSHIRE<br>CONTAINMENT SPRAY PUMP<br>P.O. No. - SNH-13-9763-006-238-3<br>PUMP S/N 14210477 | PUMP ENGINEERING DEPT<br>BINGHAM-WILLAMETTE COMPANY<br>PORTLAND OREGON & SHREVEPORT LA.<br>BINGHAM-WILLAMETTE LTD.<br>VANCOUVER B C | IMPELLER MAX. DIA. 13 3/4 | 6x10x14 B CD 1 STG. | | PUMP |
| | | MIN. DIA. | DIA. IMPELLER 12.47" x 12.47" | IMPELLER PATT. 613 CD-7 | 3560 R.P.M. |
| | | DIA. EYE AREA 69 SQ. IN. | H.P. S.G. REQUIRED | REFERENCE | CURVE NO. 35374 |

Form No. 2121

DOCUMENT
REVIEWED
JAN 1 6 1979 N.C.C.
BY
U.E.&C.

S.O. 14210477

ITEM Performance Curve

PAGE 4

(75)

BINGHAM-WILLAMETTE CO. PORTLAND, OREGON - SHREVEPORT, LOUISIANA
BINGHAM-WILLAMETTE LTD. BURNABY B.C. CANADA

# HYDRAULIC TEST DATA SHEET



| | | | | | | |
|---|---|---|---|---|---|---|
| 6x10x14B CD | 1 | UNITED ENGRG. & CONSTRUCTORS INC. / PUBLIC SERVICE CO. OF NEW HAMPSHIRE | SHH-13-4763-006- 138-3 | T-14210477-1 | | |
| 3560 \| 540 \| 3010 \| 81.5 \| 1-STG | | 69 | HM-21, 600 HP. | 14210477/80 | | |
| | 5.189" | 10" | 3600 | CS | 3-1-78 | |
| 1 \| 613CD-7 \| 4 \| 13 3/4 | 12.47" x 12.47" | $H_A$ = 29.92 = 33.8' ① / $H_{V\,HEAD}$ = .26'/1000 GPM / $H_{VP}$ = / $H_{WATER}$ ③ | CURVE No. - 35374 | START 8:00 AM | STOP 9:05 AM | |

| Test No. | Speed RPM | Suction HG. COL. in Hg | Suction ft of water ① | Discharge DWT 'B' PSI | Discharge ft of water | $H_v$ 3.34 ft per 1000 GPM | Total dynamic head ft of water | Capacity 7" ORIFACE 670 in. Hg | | GPM | Power watts read $r$ = 1400 | BHP | Pump eff % | ④ Suct. Temp °F / $H_{vp}$ | ⑤ $H_{vapor}$ FT. | NPSH FT. | Converted to constant speed = 3560 RPM TDH | GPM | BHP |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | 25.0 | 24.9 | 318 | 734.6 | – | 709.7 | – | | 0 | 190 | 342 | 0 | 70 | | | 679 | 0 | 334 |
| 2 | | 22.7 | 25.7 | 310 | 716.1 | 2.0 | 692.4 | 1.35 | | 778 | 202 | 360 | 37.8 | 70 | | | 682 | 773 | 342 |
| 3 | | 19.3 | 21.9 | 294 | 679.1 | 8.4 | 665.6 | 5.6 | | 1584 | 233 | 418 | 63.8 | 72 | | | 656 | 1574 | 409 |
| 4 | | 14.0 | 15.9 | 265 | 612.2 | 18.7 | 615.0 | 12.45 | | 2364 | 267 | 478 | 76.8 | 72 | | | 606 | 2346 | 467 |
| 5 | | 7.5 | 8.5 | 226 | 522.1 | 31.0 | 544.6 | 20.7 | | 3048 | 287 | 512 | 81.9 | 74 | | | 536 | 3025 | 501 |
| 6 | | -16.2 | -18.4 | 212 | 489.7 | 31.0 | 539.1 | 20.7 | | 3048 | 287 | 512 | | 77 / 1.0 | 2.4 | 18.8 | 531 | 3025 | |
| 7 | | 4.5 | 5.1 | 180 | 415.8 | 48.9 | 459.6 | 32.6 | | 3825 | 311 | 555 | 80.6 | 79 | | | 453 | 3796 | 543 |
| 8 | | -12.0 | -13.6 | 162 | 374.2 | 48.7 | 436.7 | 32.6 | | 3825 | 312 | 556 | | 80 / 1.2 | 3.8 | 24.3 | 430 | 3796 | |
| 9 | | -11.5 | -13.0 | 167 | 385.8 | 48.9 | 447.7 | 32.6 | | 3825 | 311 | 555 | | 80 / 1.2 | 3.8 | 25.4 | 441 | 3796 | |
| 10 | NPSH = $H_s$ + $H_a$ ± $H_v$ + $H_{V\,HEAD}$ - $H_{vp}$ = ① + ② + ③ + ④ - ⑤ | | | | | | | | | | | | | | | | | | |
| 11 | Vibration Measured On Brg. Hsgs. In Mils | | | | | | | | | | | | | | | | | | |
| 12 | | Horz | | Vert | | Axial | | | | | Witness Tested @ Portland, Oregon | | | | | | | | |
| 13 | Drive End | 0.74 | | 0.40 | | | | | | | W.R. [signature] 3/1/78 | | For United Engineers | | | | | | |
| 14 | Thrust End | 0.86 | | 0.28 | | 0.08 | | | | | [signature] | | For Bingham-Willamette | | | | | | |

DOCUMENT REVIEWED
JAN 16 1979 M.C.C.
BY
U.E.&C.

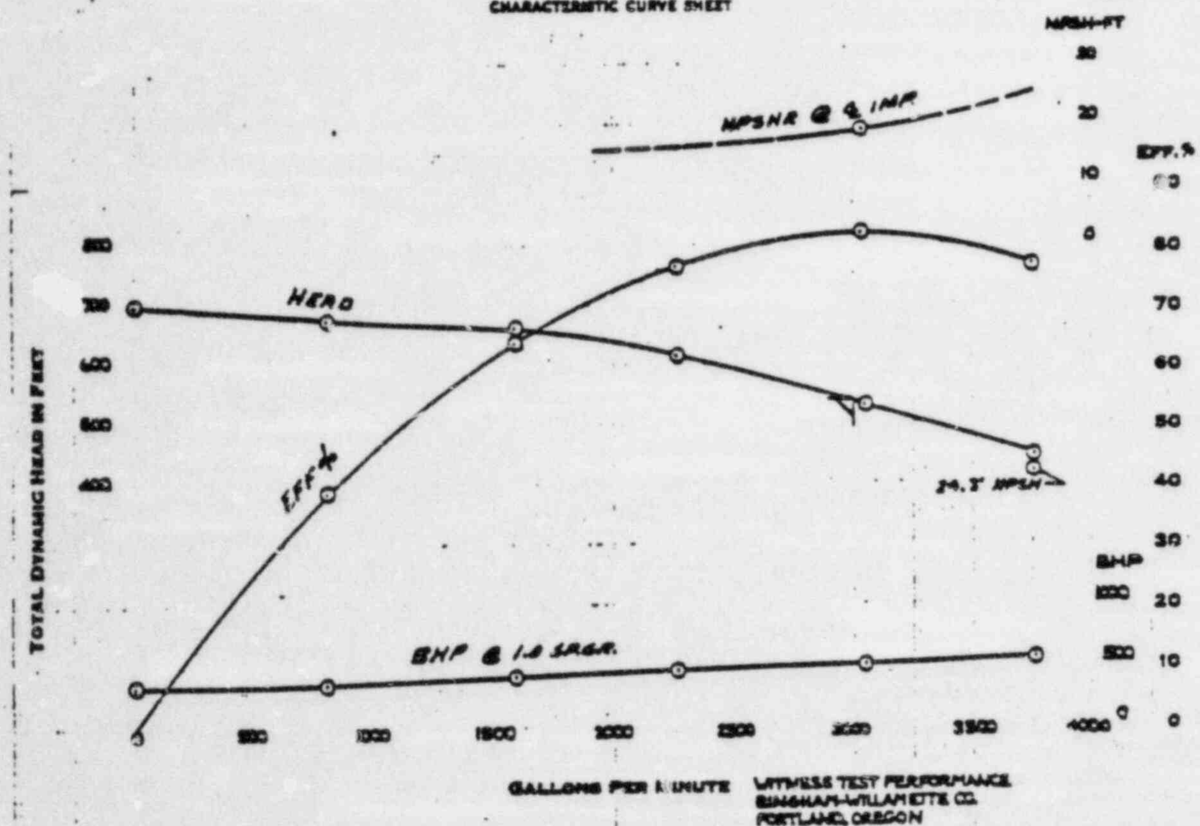
S.O. 14210477
ITEM Performance Data
PAGE 5

(76)

1-CBS-P-9B

35375

CHARACTERISTIC CURVE SHEET




WITNESS TEST PERFORMANCE
BINGHAM-WILLAMETTE CO.
PORTLAND, OREGON

| | | | | |
|---|---|---|---|---|
| UNITED ENERGY CONSTRUCT., INC.<br>PUB. SERVICE CO. NEW HAMPSHIRE<br>CONTAINMENT SPRAY PUMP<br>P.O. No.-SNH-13-7763-006-238-5<br>PUMP S/N 14210478 | PUMP ENGINEERING DEPT.<br>BINGHAM-WILLAMETTE COMPANY<br>PORTLAND, OREGON & SHREVEPORT, LA.<br>BINGHAM-WILLAMETTE LTD.<br>VANCOUVER B.C.<br>CE 9-20-77 | IMPELLER MAX. DIA. 13¾ | 6x10x14 B CD 1STG. PUMP | |
| | | MIN. DIA. | DIA. IMPELLER 12.47 x 12.47 | IMPELLER PATT. 613 CD-7 | 3560 R.P.M. |
| | | EYE AREA 69 SQ. IN. | H.P. B.H.P. REQUIRED | REFERENCE | CURVE NO. 35375 |

FORM No. 212-1

DOCUMENT
BY ...
JAN 1 6 1979 u.e.c.
BY: ____
U.E.&C.

S.O. 14210478
ITEM Performance Curve
PAGE 4

(77)

BINGHAM-WILLAMETTE CO. PORTLAND, OREGON · SHREVEPORT, LOUISIANA
BINGHAM-WILLAMETTE LTD. BURNABY B.C. CANADA

# HYDRAULIC TEST DATA SHEET



| | | | |
|---|---|---|---|
| 6x10x14 B CD | 1 | UNITED ENGRG & CONSTRUCTORS INC. PUBLIC SERVICE CO. OF NEW HAMPSHIRE | SHH-13-7763-006 338-3 |
| Pump test: T-14210478-1 | 14210477/80 | Tested by: CS | Date: 2-28-78 |
| Field: 3560, 540, 3010, 81.5, J-3234 | 69 | HM-21, 600 HP | Discharge pipe 5.189" / Suction pipe 10" / RPM 3600 |
| 1 / 613CD-7 / 4 / 12 3/4 | 12.47" x 12.67" | | Start 3:20 PM / Stop 4:40 PM |

Remarks:
$H_a = 29.79 = 33.8'$ ①
$H_{v} = .36'/1000$ GPM
$H_{vp} =$
$H_{elev} = +2.0$ ②
CURVE No. - 35375

| Run | Speed RPM | Suction HG.COL (in Hg) | Suction ft of water | Discharge DWT 'B' PSI | Discharge ft of water | | 3.34 ft per 1000 GPM | Total dynamic head ft of water | Capacity 7" ORIFACE 670 Vm. Hg (in Hg) | | GPM | Power r = 1400 Watts | BHP | Pump eff % | Shaft temp / $H_v$ | $H_{vpa}$ ft. | NPSH ft. | Corrected to 3560 RPM TDH | GPM | BHP |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | 15.7 | 17.8 | 304 | 702.5 | | 3.2 | 686.6 | 1.45 | | 807 | 202 | 361 | 38.8 | 54 / 0.5 | | | 676 | 801 | 353 |
| 2 | | 12.2 | 13.8 | 294 | 679.1 | | 8.5 | 673.8 | 5.65 | | 1573 | 238 | 425 | 63.8 | 54 / 0.5 | | | 664 | 1581 | 415 |
| 3 | | 7.7 | 8.7 | 266 | 619.5 | | 17.3 | 633.1 | 11.55 | | 2277 | 263 | 470 | 76.2 | 54 / 0.5 | | | 614 | 2260 | 459 |
| 4 | 3587 | 0.6 | 0.7 | 259 | 585.9 | | 31.3 | 586.5 | 20.9 | | 3062 | 282 | 507 | 81.8 | 55 / 0.5 | | | 578 | 3040 | 496 |
| 5 | | 2.0 | 2.3 | 175 | 404.3 | | 47.8 | 449.3 | 31.85 | | 3781 | 315 | 562 | 76.9 | 63 / 0.6 | | | 443 | 3753 | 549 |
| 6 | - | 26.4 | 29.9 | 321 | 741.5 | | - | 711.6 | - | | 0 | 190 | 341 | 0 | 63 / 0.7 | | | 741 | 0 | 333 |
| 7 | * | -11.3 | -12.5 | 214 | 493.4 | | 31.3 | 544.2 | 20.9 | | 3063 | 282 | 502 | | 66 / 0.7 | 2.9 | 19.0 | 536 | 3040 | |
| 8 | * | -11.0 | -12.5 | 164 | 378.8 | | 47.8 | 439.1 | 31.9 | | 3784 | 315 | 562 | | 69 / 0.9 | 3.7 | 26.2 | 433 | 3755 | |
| 9 | * | -13.2 | -14.5 | 156 | 360.4 | | 47.8 | 422.7 | 31.9 | | 3784 | 312 | 557 | | 69 / 0.8 | 3.7 | 29.2 | 416 | 3756 | |

10 * $NPSH = H_s + H_a \pm H_z + H_{vpa} - H_{vp}$
= ② + ① ± ③ + ④ - ⑤

11 △ VIBRATION MEASURED ON BRG HSGS. IN MILS

| | Horiz. | Vert. | Axial |
|---|---|---|---|
| Drive End | 1.1 | 0.2 | |
| Thrust End | 0.84 | 0.24 | 0.40 |

WITNESS TESTED @ PORTLAND, OREGON

W.R. Whit[illegible] 2/28/78 FOR UNITED ENGINEERS 2/28/78

O.C. Smith FOR BINGHAM-WILLAMETTE 2/28/78

DOCUMENT REVIEWED
JAN 1 6 1979 W.C.C.
BY
U.E.& C

S.O. 14210478
ITEM Performance Data
PAGE 5

(78)

STEP: Verify ECCS Flow

PURPOSE: To ensure flow to the RCS from the ECCS system

BASIS:

ECCS flow is necessary to make up for the RCS inventory changes due to either RCS shrinkage or inventory losses from the RCS.

ACTIONS:

- o Determine if there is flow from centrifugal charging pump (CCP) in each train
- o Determine if RCS pressure is less than 1550 psig
- o Determine if there is flow from SI pump in each train
- o Determine if RCS pressure is less than 200 psig
- o Determine if there is flow from RHR pumps
- o Manually start pumps and align valves

INSTRUMENTATION:

- o Indication of flow for the following:
  - CCPs
  - SI pumps
  - RHR pumps
- o ECCS pumps status indication lights
- o ECCS valves position indication lights
- o RCS pressure indication

CONTROL/EQUIPMENT:

Switches for:
- o ECCS pumps
- o ECCS valves

KNOWLEDGE:

N/A

PLANT-SPECIFIC INFORMATION:

RCS pressure is measured by train associated pressure transmitters located outside containment. Each train of pressure indication consists of a 0-3000 PSIG range indicator and a 0-700 PSIG narrow range indicator. RCS pressure is sensed at the seal table with transmitters located outside the containment.

ECCS flow indication consists of the following:

o CCP flow to cold legs, 0-1000 GPM
o SI pump flow for each train, 0-800 GPM
o RHR pump flow for each train, 0-5000 gpm

Each of these flow ranges exceed pump runout flow rates.

See attached sheets for detailed pump shutoff head values determinations.

SEABROOK STATION

Setpoint and Value Study Documentation Sheet

Setpoint/Value Description: RCS Wide Range Pressure

Determined Setpoint/Value: Wide Range 0-3000 $\pm$ 100 psig
minor grad. 100 psig
Narrow = 0-700 $\pm$ 70 psig
minor grad. 20 psig

Specific Instrument Usage:

| | | |
|---|---|---|
| RC-PI 403-1, 403-2 | 405-1, 405-2 | (Wide) |
| 403A-1, 403A-2 | 405A-1, 405A-2 | (Narrow) |

RC-PR-403
405 ] both WR & NR

References/Sources: 9763-M-510000, Standard Instrument Schedule
Specification 170-5, Panel Mounted Indicators

Assumptions: Error = $\pm$ 3%

Calculations:

Wide Range:

Error = 3000 x $\pm$ .03 = $\pm$ 90 psig
Round up to $\pm$ 100 psig

Narrow Range:

$$\text{Error} = \sqrt{5 + \left(2 \times \frac{700}{3000}\right)^2}$$

$$= \sqrt{5 + .2}$$

$$= \pm 2.28 \text{ of } P_T \text{ span}$$

$$= \pm 68.4 \sim \pm 70 \text{ psig}$$

SEABROOK STATION

Setpoint and Value Study Documentation Sheet

Setpoint/Value Description: The plant-specific value for the shutoff head pressure of the SI pumps plus allowances for normal channel accuracy.

Determined Setpoint/Value: 1570 psig $\pm$ 90 psig at 0 gpm
1550 psig $\mp$ 90 psig at 45 gpm miniflow

Specific Instrument Usage: PI-405-1, PI-405-2 (100 psig graduations)
PI-403-1, PI-403-2

References/Sources: See pump performance curves attached.

Assumptions:

a) Assume NPSHR at maximum flow (650 gpm) for pump suction inlet head.

b) $\pm$ 3% instrumentation error

Calculations:

a) At 0 gpm pump shutoff head (from curves) is 3,600 ft. and NPSHR at 650 gpm is 25 ft. Then the discharge head is equal to the sum of the TDH and the suction head (NPSHR).

discharge head = 3,600 + 25 = 3,625 ft.

Convert discharge head to pressure

discharge pressure = (discharge head) $\div$ (2.31)

therefore, discharge pressure =

(3,625) $\div$ (2.31) = 1,570 psig

b) At 45 gpm pump shutoff head, miniflow, (from curves) is 3,560 ft. and NPSHR at 650 gpm is 25 ft.

discharge head = 3,560 + 25 = 3,585 ft.

therefore, discharge pressure =
(3,585) $\div$ (2.31) = 1,552 psig

c) Pressure error = 3,000 x .03 = $\pm$ 90 psig
Round to $\pm$ 100 psig

User note: Use value with miniflow and round to
1550 PSIG $\pm$ 90
VALUE = 14$\overline{5}$0 PSIG

CONTRACTOR WESTINGHOUSE NES

CUSTOMER NEW HAMPSHIRE

ITEM NO. NAH.-01 P.O. 546-CAV-236951-GPE

IMPELLER PATTERN M-7814 M-7592

MAXIMUM DIAMETER 7 9/16 8 9/16

RATED DIAMETER 8 9/16 STGS 2-4 8 7/16 : 5-11 8 5/16

MINIMUM DIAMETER 7 9/16 7 9/16

TEST PERFORMANCE CURVE NO. 37735 N

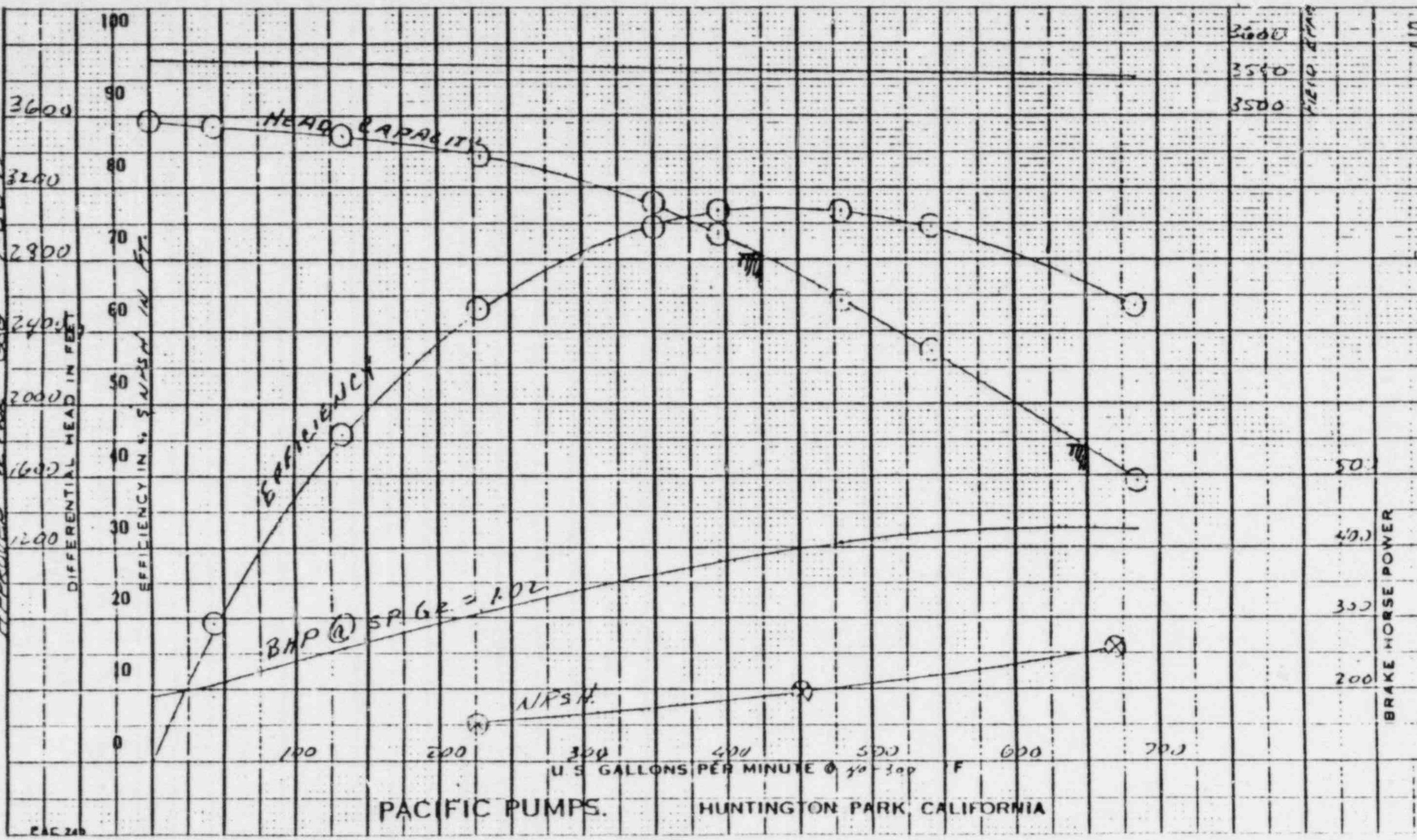
SIZE 8" TYPE JHF STAGES 11

R.P.M. FIELD DATE 9-21-77

PUMP NUMBER 51661 1-SI-P-6A

PERFORMANCE ALSO APPLIES TO PUMP

NUMBER




APPROVED W PWR CSG 9-28-77

(83)

CONTRACTOR WESTINGHOUSE N/ES

CUSTOMER NEW HAMPSHIRE

ITEM NO. NAH-02 P.O. 546-CAV-236957-BPE

IMPELLER PATTERN M-7844 M-7592

MAXIMUM DIAMETER 8 9/16 8 9/16

RATED DIAMETER 8 9/16 STGS 2-5 8 9/16 : 6-11 8 5/16

MINIMUM DIAMETER 7 9/16 7 9/16

TEST PERFORMANCE CURVE NO. 37735 2

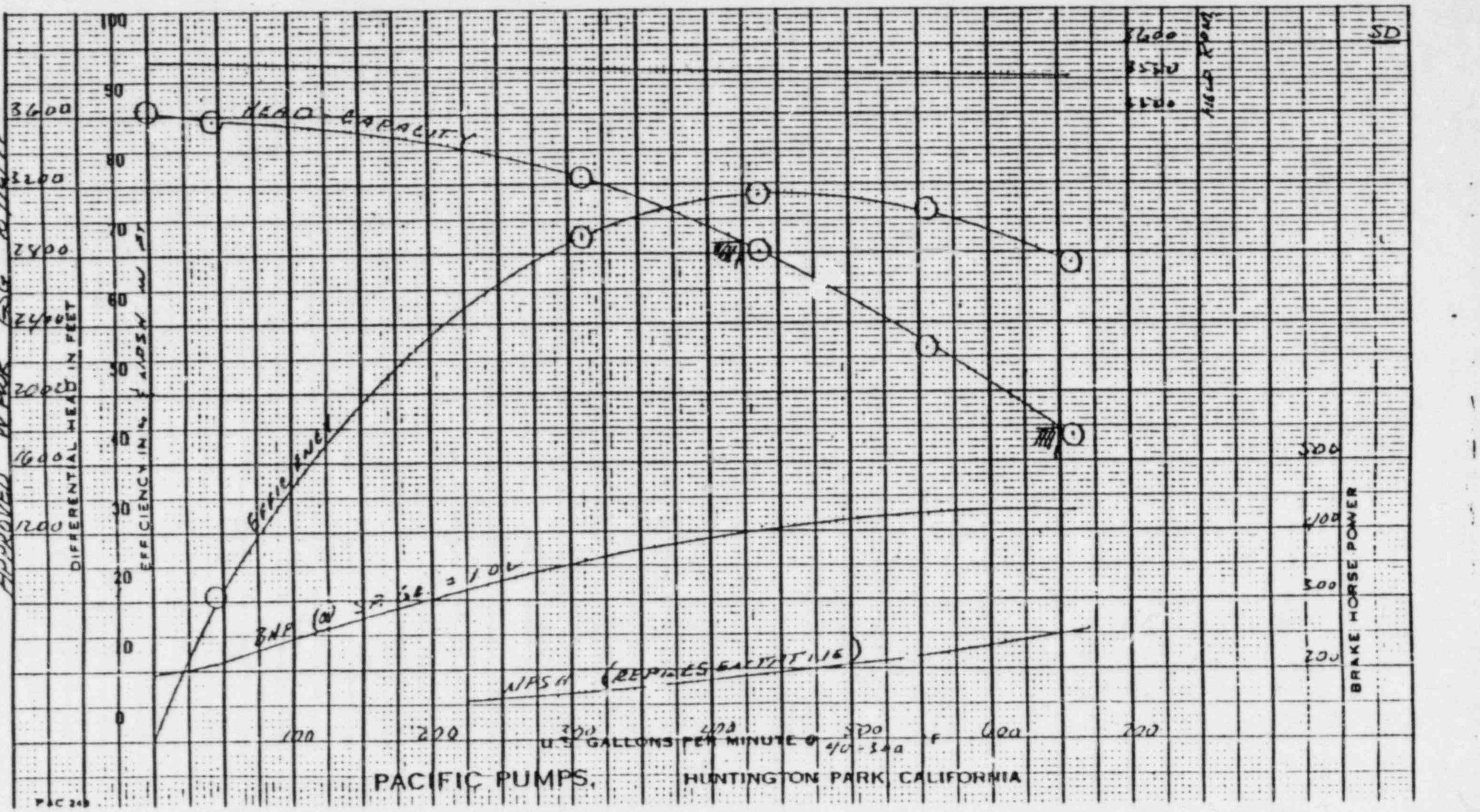
SIZE 3" TYPE JHF STAGES 11

R.P.M. FIELD DATE 10-3-77

PUMP NUMBER 51662 1-SI-P-6B

PERFORMANCE ALSO APPLIES TO PUMP

NUMBER




PACIFIC PUMPS, HUNTINGTON PARK, CALIFORNIA

(8-4)

SEABROOK STATION

Setpoint and Value Study Documentation Sheet

Setpoint/Value Description: The plant-specific value for the shutoff head pressure of the RHR pumps plus allowances for normal channel accuracy.

Determined Setpoint/Value: 206 psig ± 20 psig at 0 gpm
200 psig ± 20 psig at 500 gpm miniflow
190 psig ± 20 psig at 1,255 gpm miniflow

Specific Instrument Usage: 1 RHR-PI-614, 1 RHR-PI-615
(20 psig graduations)

References/Sources: See pump performance curves attached.

Assumptions:

a) Assume NPSHR at 3,800 gpm for pump suction inlet head.

b) ± 3% instrumentation error.

Calculations:

a) At 0 gpm pump shutoff head (from curves) is 460 ft. and NPSHR at 3,800 gpm is 15.5 ft. Then the discharge head is equal to the sum of the TDH and the suction head (NPSHR).

discharge head = 460 + 15.5 = 475.5 ft.

Convert discharge head to pressure

discharge pressure = (discharge head) ÷ (2.31)

therefore, discharge pressure =

(475.5) ÷ (2.31) = 206 psig

b) At 500 gpm pump shutoff head, miniflow-min (from curves) is 445 ft. and NPSHR at 3,800 gpm is 15.5 ft.

discharge head = 445 + 15.5 = 460.5 ft.

therefore, discharge pressure =

(460.5) ÷ (2.31) = 200 psig

c) At 1,255 gpm pump shutoff head, miniflow-mir (from curves) is 425 ft. and NPSHR at 3,800 gpm is 15.5 ft.

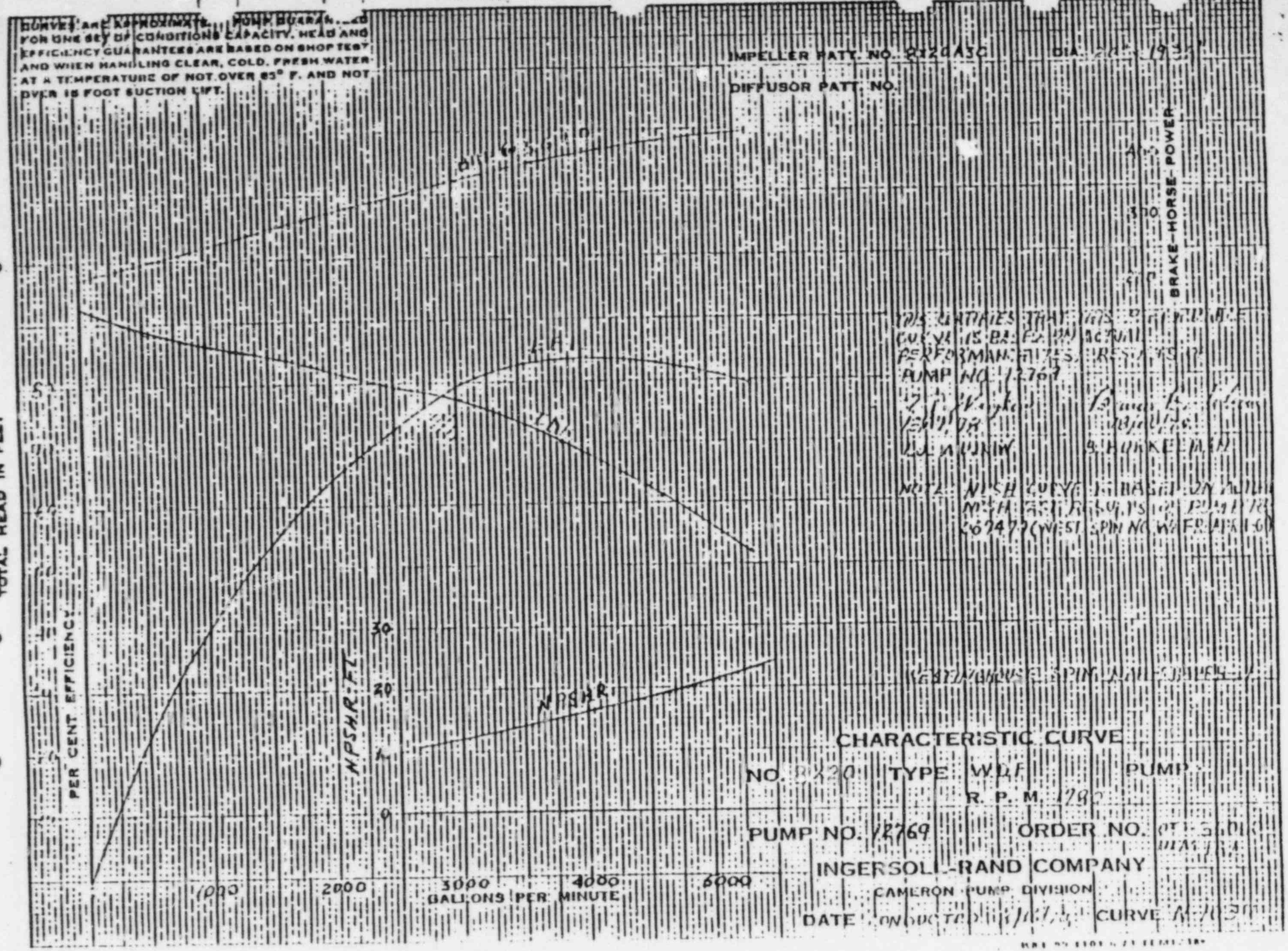
discharge head = 425 + 15.5 = 440.5 ft.

therefore, discharge pressure = (440.5) ÷ (2.31) = 190 psig

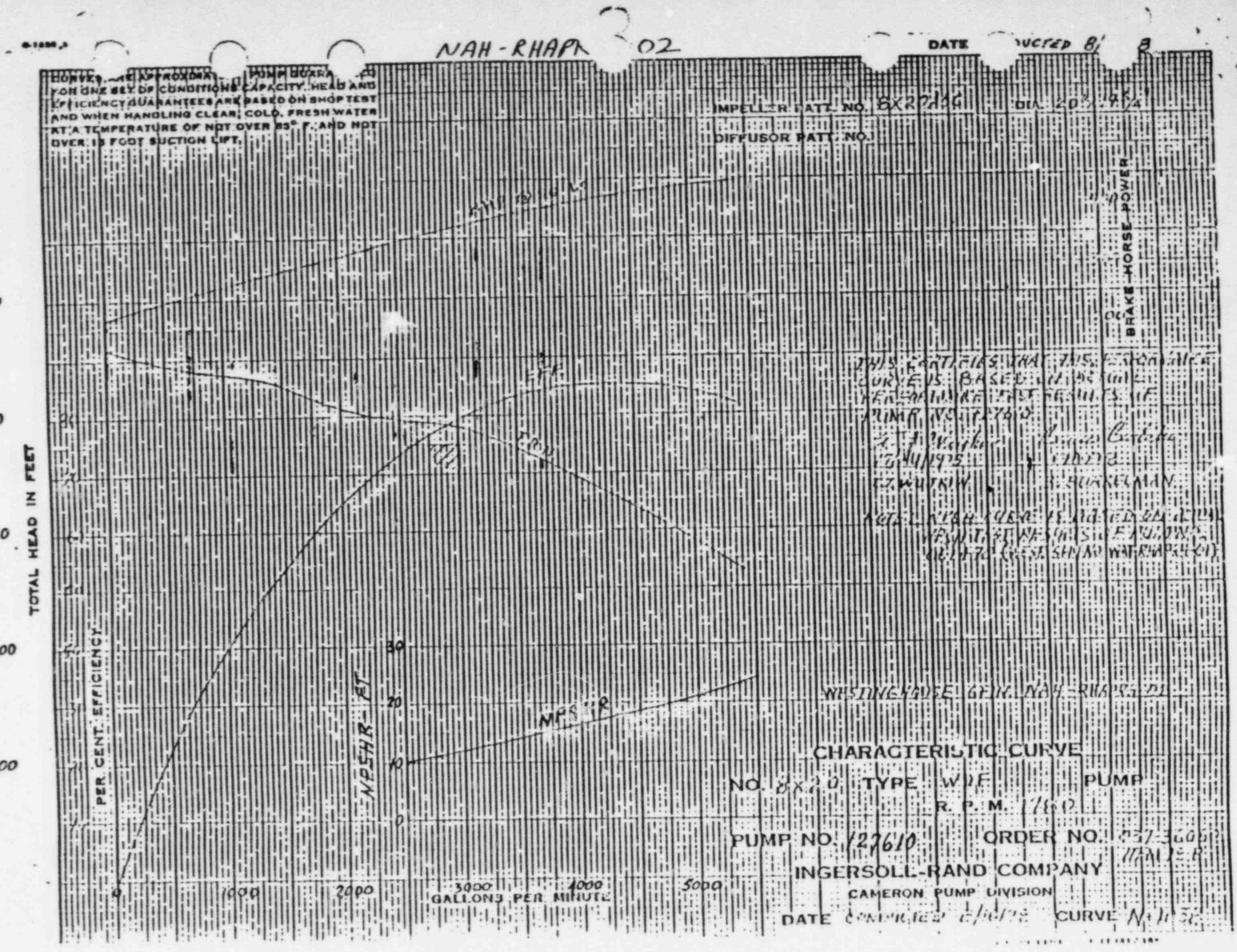
d) Pressure error = 700 x .03 = ± 21 psig 20 psig

NAH-RHAI. -01

CURVE NO. — DATE C ICTED 8/




(87)


NAH-RHAP 02
DATE
CURVES ARE APPROXIMATE. PUMP GUARANTEED FOR ONE SET OF CONDITIONS CAPACITY, HEAD AND EFFICIENCY GUARANTEES ARE BASED ON SHOP TEST AND WHEN HANDLING CLEAR, COLD, FRESH WATER AT A TEMPERATURE OF NOT OVER 85° F. AND NOT OVER 15 FOOT SUCTION LIFT.
IMPELLER PATT. NO. 8X20 DIA. 20
DIFFUSOR PATT. NO.
BRAKE HORSE POWER
TOTAL HEAD IN FEET
500
400
300
200
100
PER CENT EFFICIENCY
NPSHR - FT
30
20
10
0
NPSHR
0
1000
2000
3000
4000
5000
GALLONS PER MINUTE
CHARACTERISTIC CURVE
NO. 8x20 TYPE WDF PUMP
R. P. M. 1780
PUMP NO. 127610 ORDER NO.
INGERSOLL-RAND COMPANY
CAMERON PUMP DIVISION
DATE CURVE
88

STEP: Verify EFW Flow - GREATER THAN 470 GPM TOTAL COMBINED FLOW TO AT LEAST TWO SGs

PURPOSE: To ensure EFW flow to the steam generators

BASIS:

EFW flow is necessary for secondary heat sink. If adequate EFW flow for decay heat removal cannot be established, the transition to the FR-H.1, RESPONSE TO LOSS OF SECONDARY HEAT SINK, is necessary to establish an alternate source of feed flow or an alternate heat sink.

ACTIONS:

- o Determine if EFW flow greater than 470 gpm
- o Determine if EFW flow greater than 470 gpm cannot be established
- o Manually start pumps and align valves as necessary
- o Transfer to FR-H.1, RESPONSE TO LOSS OF SECONDARY HEAT SINK, step 1

INSTRUMENTATION:

- o EFW flow indication for each steam generator

CONTROL/EQUIPMENT:

Switches for:

- o EFW pumps
- o EFW flow control valves
- o EFW steam supply valves to steam-driven pump turbine

KNOWLEDGE:

N/A

PLANT-SPECIFIC INFORMATION:

EFW flow indicators are provided in the EFW line to each SG. Each indicator has a range of 0-500 GPM. This flow range covers all expected flow ranges, even with only two SGs available for heat removal ie; 235 GPM to each of two SGs.

For normal conditions, the required EFW flow to each of four SGs would be approximately 120 GPM. With three SGs available for decay heat removal, the required flow to each SG would be approximately 160 GPM.

Each of the two EFW pumps can deliver feed in excess of the required total combined flow of 470 GPM to at least two SGs as assumed in the main feedline break safety analysis.

A curve is attached which shows total EFW flow required to remove decay heat versus time after trip. This curve shows actual EFW flow requirements with respect to time.

The EFW pumps, both motor driven and turbine driven, have identical ratings which are given below:

EMERGENCY FEEDWATER PUMP DATA

| | |
|---|---|
| Total Number Per Unit | 2 |
| Electric Motor Driven | 1 |
| Turbine Driven | 1 |
| Design Flow (each) | 710 gpm |
| Design Head | 3050 ft. (1320 psi) |
| Feedwater Design Temperature | 50-100°F |
| Required BHP | 770 |
| Motor Size, HP | 900 |
| Turbine Rating, HP | 900 |

Either EFW pump is capable of delivering required flow. In most cases, the operator must throttle EFW flow to avoid excessive plant cooldown after determining that the minimum EFW flow capability is met.

See attached sheets.

SEABROOK STATION

Setpoint and Value Study Documentation Sheet

Setpoint/Value Description: Minimum EFW flow assumed in Safety Analysis

Determined Setpoint/Value: 470 GPM to at least two SGs

Specific Instrument Usage: FI-4214-2; FI-4224-2; FI-4234-2; FI-4244-2
FR-4214, FR-4224

References/Sources: FSAR Safety Analysis assumptions for main feedline break
FSAR Chapter 15, Section 15.2.8.2(a)(10)

Assumptions: N/A

Calculations: N/A

## SEABROOK STATION

### Setpoint and Value Study Documentation Sheet

**Setpoint/Value Description:** EFW Indication Error

**Determined Setpoint/Value:** Range: FI / FR 0-500 ± 20 gpm  Scale Grad. 20 gpm

**Specific Instrument Usage:** FW-FI-4214-2, -4224-2, -4234-2, -4294-2
FW-FR-4214, -4224

**References/Sources:**

1. 9763-M-510000 Standard Instrument Schedule
2. Specification 170-5, Panel Mounted Indicators
3. Specification 170-4, Recorders

**Assumptions:**

1. PEA for an orifice = +/- 2%

**Calculations:**

Error = (235 gpm) in % gpm

$$\text{Error} = \sqrt{\left|\sqrt{\frac{PEA^2 + (SCA + SD)^2 + STE^2 + (RCA + RD)^2 + RTE^2}{2}}\;\frac{(500)}{(235)}\right|^2 + IA^2}$$

$$= \sqrt{\left|\sqrt{\frac{(2)^2 + (0.5 + 1.0)^2 + 0.5^2 + (0.5 + 1.0)^2 + (0.5)^2}{2}}\;\frac{(500)}{(235)}\right|^2 + 2^2}$$

$$= \sqrt{\left|\sqrt{4 + 2.25 + .25 + 2.25 + .25 \times 1.06}\right|^2 + 4}$$

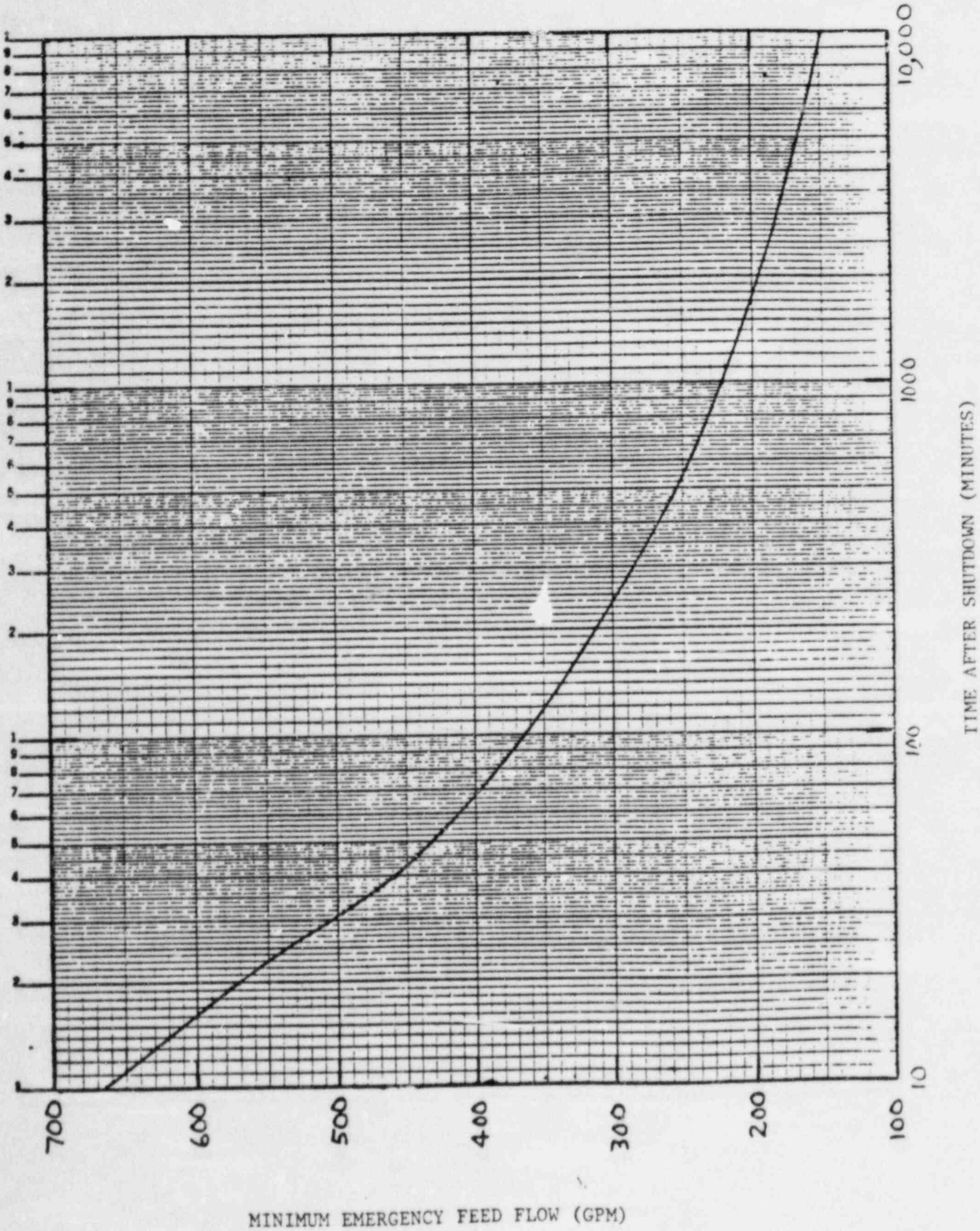
$$= \sqrt{10.2 + 4} = \pm 3.7\% \text{ ; } 500 \times \pm 3.7\% = \pm 18.8 \sim \pm 20 \text{ gpm}$$

## SEABROOK STATION

### Setpoint and Value Study Documentation Sheet

| | |
|---|---|
| Setpoint/Value Description: | Minimum EFW Flow requirement for heat removal plus allowances for normal channel accuracy. |
| Determined Setpoint/Value: | See the attached figure. Allowances for normal channel accuracy are shown. |
| Specific Instrument Usage: | FW-FI-4214-2,-4224-2,-4234-2,-4244-2 |
| References/Sources: | "Residual Decay Energy for Light-Water Reactors for Long-Term Cooling," NRC Branch Technical Position ASB 9-2, contained in NUREG-0800 (Standard Review Plan), published in July 1981. |
| Assumptions: | Residual core heat is calculated using Reference 1. Reactor coolant pump heat is included. The EFW is assumed to take suction from the condensate storage tank. Steam is vented to atmosphere through the steamline safety valves. |
| Calculations: | See SBC-68, "Minimum EFW Flow for Decay Heat Removal." |

SEABROOK NUCLEAR POWER STATION



STEP: Verify EFW Valve Alignment - PROPER EMERGENCY ALIGNMENT

PURPOSE: To ensure the EFW valves are properly aligned to feed the steam generators

BASIS:

Although minimum EFW flow is verified in a previous step, it is important to verify all valves are properly aligned such that all non-faulted SGs are being fed. Should a SG be faulted (depressurized), a high EFW flow to that SG would result. The high flow, indicative of faulted SG, would cause automatic isolation of that EFW line to preserve EFW flow to intact SGs.

ACTIONS:

- o Determine if EFW valves are properly aligned for emergency
- o Align EFW valves as necessary

INSTRUMENTATION:

Remote operated EFW valves position indication lights

CONTROL/EQUIPMENT:

Switches for EFW valves

KNOWLEDGE:

A high EFW flow (offscale high) indicates a faulted SG or EFW line

PLANT-SPECIFIC INFORMATION:

Automatic EFW isolation to a SG occurs when the flow to a faulted line or SG exceeds a 450 GPM setpoint. If a SG is faulted, the operator is instructed not to reopen valves to a faulted SG. If the associated SG is not faulted, then the operator is instructed to check that the EFW line is intact before reestablishing EFW flow to that SG.

See attached sheet.

SEABROOK STATION

Setpoint and Value Study Documentation Sheet

Setpoint/Value Description: EFW Automatic Isolation - High Flow

Determined Setpoint/Value: 450 GPM nominal value

Specific Instrument Usage: N/A

References/Sources:

- o FSAR Chapter 6, Section 6.8 Emergency Feedwater System
- o Site specific value that is on range (0-500 gpm) and high enough above normal flow (235 gpm) to prevent spurious isolation.
- o Setpoint Data List 9763-M-500376

Assumptions: N/A

Calculations: N/A

STEP: Verify ECCS Valve Alignment - PROPER EMERGENCY ALIGNMENT INDICATED ON STATUS PANELS

PURPOSE: To ensure the ECCS valves are properly aligned for inventory makeup

BASIS:

Although ECCS flow is verified in a previous step, it is important to verify all trains are properly aligned such that if one train is lost, the other train would still be available.

ACTIONS:

- o Determine if ECCS valves are properly aligned for emergency
- o Align ECCS valves as necessary

INSTRUMENTATION:

- o Remote operated ECCS valves position indication lights on status panels
- o Individual ECCS valve position indication lights

CONTROL/EQUIPMENT:

Switches for ECCS valves

KNOWLEDGE:

N/A

PLANT-SPECIFIC INFORMATION:

Dedicated light status panels are provided for the following ECCS modes in each train so that the operator can determine at a glance that valve alignments are correct:

- o Cold leg injection
- o Cold leg recirculation
- o Hot leg recirculation

Any valve(s) that are not in the correct alignment can be positioned manually.

STEP: Check RCS Cold Leg Temperature - STABLE AT OR TRENDING TO 557°F

PURPOSE: To ensure that RCS heat is being properly removed through the secondary side

BASIS:

RCS temperature stable at or trending to the no-load value indicates that the secondary steam dump system is operating as designed. If the RCS cooldown is excessive, then steam dump should be stopped. Excessive feed to the steam generators can also result in cooling down the RCS and it may be necessary to reduce feed flow to the minimum for decay heat removal until SG level is in the narrow range. If the cooldown continues, the main steamlines are isolated to stop any steam leakage downstream of the MSIVs, such as a stuck open condenser steam dump valve.

If RCS temperature is greater than no-load and increasing, then steam dump from the secondary must be increased for decay heat removal.

ACTIONS:

- o Determine if RCS average temperature is stable at or trending to 557°F
- o Determine if temperature less than 557°F and decreasing
- o Determine if RCS cooldown continues
- o Determine if temperature greater than 557°F and increasing
- o Maintain total feed flow greater than 470 gpm until narrow range level greater than 5% [35% for adverse containment] in at least one SG
- o Close main steamline isolation and bypass valves
- o Dump steam to condenser
- o Dump steam using SG ASDVs

INSTRUMENTATION:

- o RCS average temperature indication
- o Indication of position for
  - Condenser steam dump valves
  - SG ASDVs
  - Main steamline isolation and bypass valves
  - EFW flow control valves
- o SG narrow range level indication
- o EFW flow indication

CONTROL/EQUIPMENT:

Controls for:
- o Condenser steam dump valves
- o SG ASDVs
- o EFW flow control valves
- o Main steamline isolation and bypass valves
- o Low low $T_{AVG}$ (P-12) interlock reset

KNOWLEDGE:

Use wide range loop RTDs if RCPs are not running

PLANT-SPECIFIC INFORMATION:

If RCPs are running, average temperature is read on the $T_{AVG}$ recorder which has a range of 530°F - 630°F. In cases where the RCPs are tripped, average temperature is observed on the following wide range temperatures instruments:

- o Loop hot leg indicators, 0-700°F, one per loop
- o Loop cold leg indicators, 0-700°F, one per loop
- o Loop hot leg recorder, 0-700°F, one per loop
- o Loop cold leg recorder, 0-700°F, one per loop

Wide range temperature is measured by RTDs inserted in loop thermowells.

See attached sheets.

SEABROOK STATION

Setpoint and Value Study Documentation Sheet

Setpoint/Value Description: No-load RCS temperature

Determined Setpoint/Value: 557°F

Specific Instrument Usage: N/A

References/Sources:

1. FSAR Figure 4.4-11.
2. "Precautions, Limitations and Setpoints for Seabrook Station, NAH-U-2781, May 9, 1983.
3. V. M. Thomas, "Setpoint Study for PSNH - Seabrook Station Units 1 and 2", W Proprietary, WCAP-10136, August 1982.

Assumptions: Used in the plant thermal-hydraulic analysis.

Calculations: See Section 4.4 of the FSAR.

SEABROOK STATION

Setpoint and Value Study Documentation Sheet

Setpoint/Value Description: Low-Low $T_{avg}$ Interlock (P-12) setpoint.

Determined Setpoint/Value: 550°F

Specific Instrument Usage: RC-TI-412,-422,-432,-442, RC-TR-412

References/Sources: 1. C. R. Tuley, et al., "Westinghouse Setpoint Methodology for Protection and Control Systems - Seabrook Station," W Proprietary, November 1982.

Assumptions: N/A

Calculations: N/A

SEABROOK STATION

Setpoint and Value Study Documentation Sheet

Setpoint/Value Description: S/G Level (wide & narrow)

Determined Setpoint/Value: Range: 0-100% (see error table below)

Specific Instrument Usage:

| | S/G A | S/G B | S/G C | S/G D |
|---|---|---|---|---|
| Narrow | FW-LI-517, 518 519, 551 LR-519 | LI-527, 528 529, 552 LR-529 | LI-537, 538 539, 553 LR-539 | LI-547, 548, 549, 554 LR-549 |
| Wide | LI-501 LR-501 | LI-502 LR-502 | LI-503 LR-501 | LI-504 LR-502 |

References/Sources: 1, 2, 3, RAI 420.23

Assumptions:

Calculations: Normal Error $= \pm \sqrt{(PMA)^2 + (Loop\ Error)^2}$

$= \pm \sqrt{(2)^2 + (3)^2}$

$= \pm \sqrt{13}$

$= \pm 3.6\%$

Errors

| ACTUAL S/G LEVEL | CONDITION: NORMAL | CONDITION: MSLB @ NO LOAD TIME | CONDITION: MSLB @ 350°F |
|---|---|---|---|
| 0% | ± 3.6% | + 34.6% − 2.6% | + 31.2% − 6% |
| 100% | ± 3.6% | + 34.6% − 2.6% (round to + 35%) | + 48.7% + 11.6% |

CONTINUED

(102)

Error (MSLB no load $T_{ave}$) = Error (Normal) + EA + Ref. Leg Error

$$= \pm 3.6\% \pm 15\% + 16 = \begin{matrix} +\ 34.6\% \\ -\ 2.6\% \end{matrix}$$

Where Ref. Leg Error = $\dfrac{R\Delta\rho R}{S\ (\rho_{f,cal} - \rho_{g,cal})}$

(See page 1 of RAI 420.23, attached)

Assumptions: $R = S$
$T_{cal} = 120°F$
$T_{acc} = 375°F$
$V_{120} = .01620\ ft^3/lb$, $\rho_{120} = 61.73\ lb/ft^3$
$V_{375} = .01829\ ft^3/lb$, $\rho_{375} = 54.7\ lb/ft^3$
$V_{g,cal} = 0.4456\ ft^3/lb$, $\rho_{g,cal} = 2.24\ /ft^3$
$V_{f,cal} = 0.0217\ ft^3/lb$, $\rho_{f,cal} = 46.1\ b/ft^3$

$$= \frac{(61.73 - 54.7)}{(46.1 - 2.24)} = +\ 16\%$$

Error (MSLB 350°F) = Error (Process) + EA + Ref. Leg Error

$$\text{Error (Process)} = \frac{-R\Delta\rho_g - L\ (W\rho f - \Delta\rho g)}{S\ (\rho_{f,cal} - \rho_{g,cal})}$$

$V_{f350} = 0.01912\ ft^3/lb$, $\rho_{f350} = 52.3\ lb/ft^3$
$V_{g350} = 1.325\ ft^3/lb$, $\rho_{g350} = 0.754\ lb/ft^3$

$$\text{Error } (0\%) = -\frac{(2.24 - 0.754)}{(46.1 - 2.24)} = -\ 3.4\%$$

$$\text{Error } (100\%) = -\frac{(2.24 - 0.754) - 1\ ([46.1 - 52.3] - [2.24 - .754])}{(46.1 - 2.24)}$$

$$= +\ 14.1\%$$

| LEVEL | PROCESS | EA | REF LEG | NORMAL | TOTAL |
|---|---|---|---|---|---|
| 0% | -3.4 | ± 15% | +16 | ± 3.6 | +31.2%<br>- 6 % |
| 100% | +14.1 | ± 15% | +16 | ± 3.6 | +48.7%<br>+11.6% |

ERRORS

CONTINUED

420.23
(7.2)

Describe how the effects of high temperatures in reference legs of steam generator and pressurizer water level measuring instruments subsequent to high energy breaks are evaluated and compensated for in determining setpoints. Identify and describe any modifications planned or taken in response to IEB 79-21. Also, describe the level measurement errors due to environmental temperature effects on other level instruments using reference legs.

RESPONSE: 5/83

The error in dp level measurement systems due to changes in fluid densities is:

$$E = \frac{R(\Delta\rho_R - \Delta\rho_g) - L(\Delta\rho_f - \Delta\rho_g)}{S(\rho_{f,cal} - \rho_{g,cal})} \times 100$$

where:

$E$ = Error in % span

$R$ = Height of reference leg water level above the variable leg tap

$S$ = Span (distance between taps)

$L$ = Water level above the variable tap

$\rho g_{cal}$ = Vapor calibration density

$\rho f_{cal}$ = Process fluid calibration density

$\Delta\rho_R$ = Change in reference leg density from the calibration value

$\Delta\rho_g$ = Change in vapor density from $\rho_{g,cal}$

$\Delta\rho_f$ = Change in process fluid density from $\rho_{f,cal}$

Note: $\Delta\rho = \rho$ cal $- \rho$ accident

This error determination assumes that the reference leg and variable leg below the variable tap are at the same temperature and produce counteracting errors.

A. Effects of Post-Accident Conditions on Indicated Level

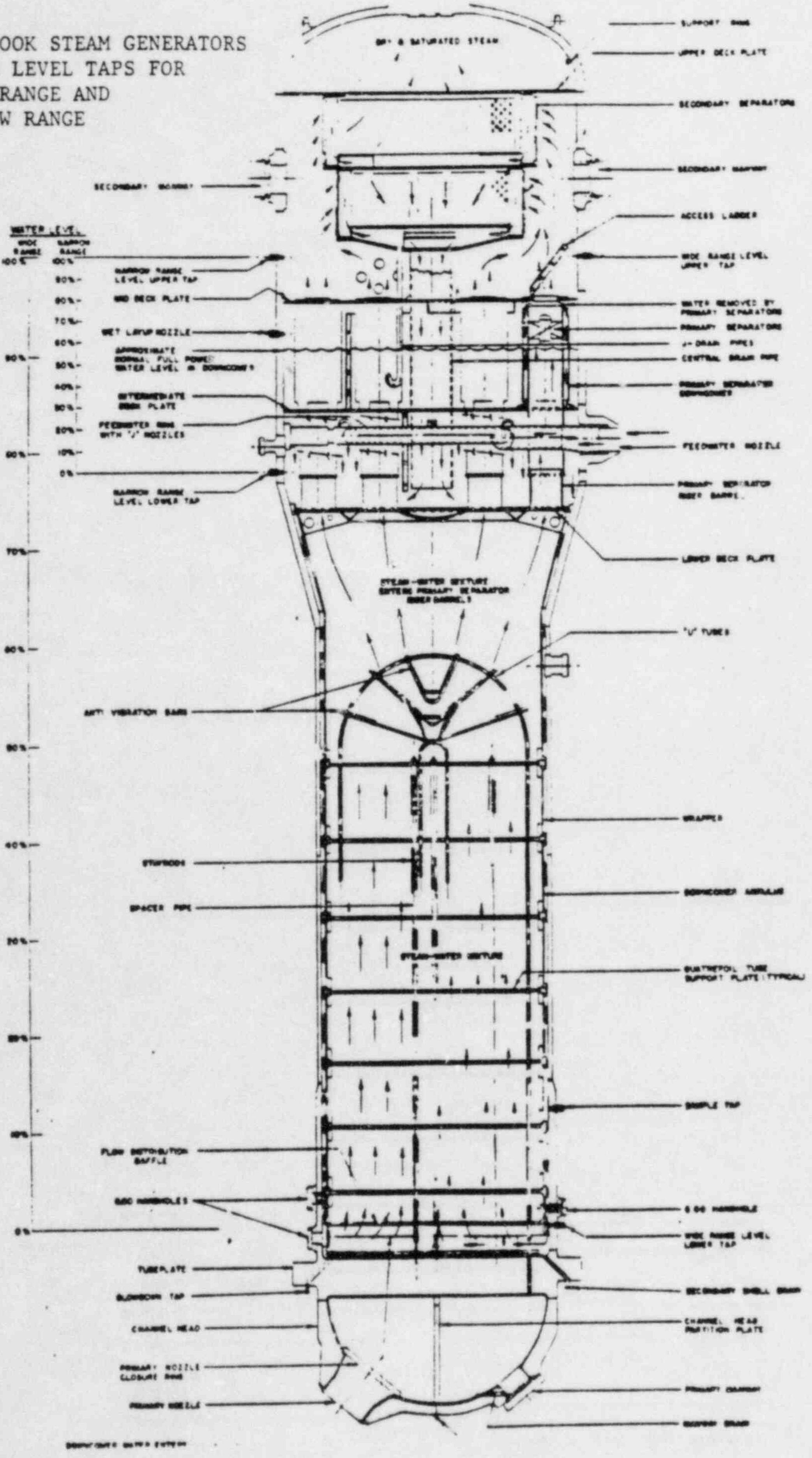
1. Reference Leg Heatup

If the process conditions are not affected by the accident, the error due to reference leg heatup is:

$$E = \frac{R\Delta\rho_R}{S(\rho_{f,cal} - \rho_{g,cal})}$$

A decrease in reference leg density will increase the indicated level.

SEABROOK STEAM GENERATORS
WATER LEVEL TAPS FOR
WIDE RANGE AND
NARROW RANGE



STEP DESCRIPTION TABLE FOR E-0 STEP 20

STEP: Check PRZR PORVs And Spray Valves

PURPOSE: To check that the PRZR PORVs and spray valves are not causing an RCS depressurization

BASIS:

An open PRZR PORV or spray valve may cause an RCS depressurization. The operator checks that these valves are closed if PRZR pressure is below the appropriate setpoints.

If the PRZR pressure is below 2385 psig or less than the LTOP setpoint and any PRZR PORV or its block valve cannot be closed, the operator is instructed to transfer to procedure E-1, LOSS OF REACTOR OR SECONDARY COOLANT, to address this equivalent small break LOCA condition. If the PRZR pressure is below 2260 psig and any normal PRZR spray valve cannot be closed, the operator is instructed to stop any RCP supplying the failed spray valve in order to minimize the RCS depressurization.

ACTIONS:

- Determine if PRZR PORVs are closed
- Determine if PRZR pressure is less than 2385 psig or less than LTOP setpoint
- Determine if any PRZR PORV cannot be closed
- Determine if any PRZR PORV block valve cannot be closed
- Determine if normal PRZR spray valves are closed
- Determine if PRZR pressure is less than 2260 psig
- Determine if normal PRZR spray valves cannot be closed
- Close PRZR PORVs
- Close PRZR PORV block valves
- Transfer to E-1, LOSS OF REACTOR OR SECONDARY COOLANT, step 1
- Close normal PRZR spray valves
- Stop RCP(s) supplying failed spray valve(s)

INSTRUMENTATION:

- PRZR pressure indication
- RCS pressure indication
- PORV and block valve position indication lights
- Normal PRZR spray valves position indication lights
- RCPs status indication lights

CONTROL/EQUIPMENT:

Switches for:
- o PRZR PORVs and block valves
- o Normal PRZR spray valves
- o RCPs

KNOWLEDGE:

- o PORV discharge line temperature response
- o RCPs supplying spray valves

PLANT-SPECIFIC INFORMATION:

Pressurizer pressure is measured in the range of 1700-2500 PSIG.

RCS pressure is measured in the ranges of 0-3000 PSIG and 0-700 PSIG.

The Low Temperature-Overpressurization Protection (LTOP) system automatically ramps down the pressurizer PORV pressure setpoint as a function of RCS temperature. The LTOP system is armed at 350°F decreasing RCS temperature. The attached curve shows the PORV pressure setpoint for all temperatures down to the minimum temperature of 190°F. For all temperatures below 190°F, the PORV setpoint remains at 450 PSIG.

Pressurizer spray is provided from loop three and loop one cold loop. The RCPs associated with these loops are powered from different 13.8 KV busses. The pressurizer surge line is connected to loop three hot leg.

The pressurizer spray valves are air operated and are designed to fail closed.

See attached sheets.

SEABROOK STATION

Setpoint and Value Study Documentation Sheet

Setpoint/Value Description: The pressurizer PORV pressure setpoint.

Determined Setpoint/Value: 2385 psig @ 350°F

Specific Instrument Usage: PI455A; PI456; PI457; PI458

References/Sources:

1. "Analysis of the P-9 Setpoint," Memo from J. D. Robichaud/A. E. Ladieu to J. DeVincentis, TAG 83-105, July 14, 1983.
2. "P-9 Setpoint Analysis," Letter from D. E. Moody to John DeVincentis, SS# 11038, July 28, 1983.
3. "P-9 Setpoint Analysis," Memo from A. E. Ladieu to J. DeVincentis, TAG 83-195, August 5, 1983.

Assumptions: The setpoint is high enough to minimize PORV challenges yet low enough to minimize pressurizer safety valve challenges.

Calculations: See SBC-42, "Analysis of the P-9 Setpoint."

## SEABROOK STATION

### Setpoint and Value Study Documentation Sheet

Setpoint/Value Description: Arming temperature setpoint below which the LTOP protection system is in service to operate pressurizer PORVs.

Determined Setpoint/Value: 350°F

Specific Instrument Usage: TR413A; TR433A; TR413B; TR433B

References/Sources: "Seabrook LTOP Setpoints," Memo from A. E. Ladieu to J. DeVincentis, NED 82-367, June 21, 1982.

Assumptions: Stated in above reference.

Calculations: See SBC-29, "Low Temperature Overpressure Protection."

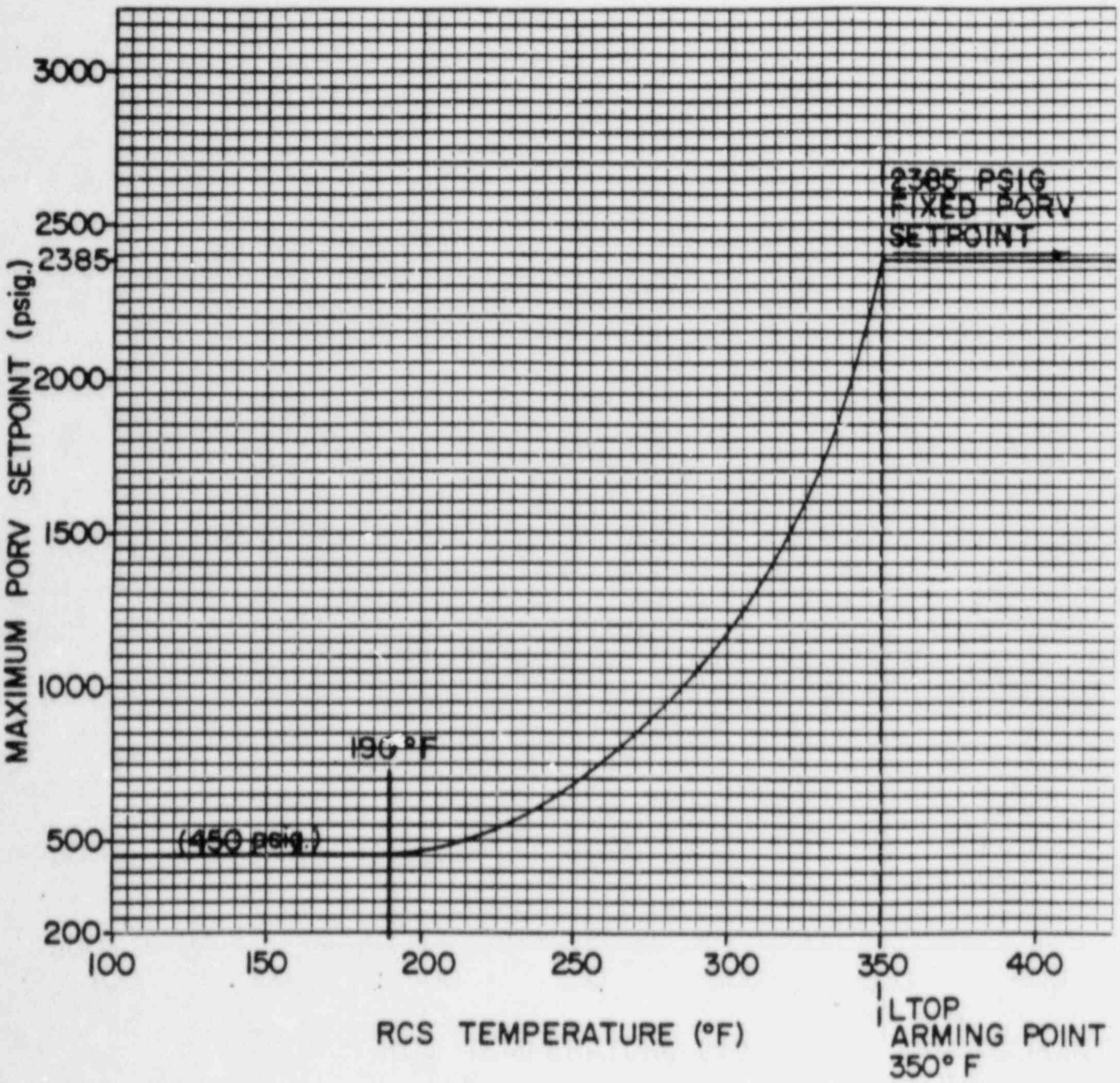
LTOP setpoint algorithm : PORVs

1) $P = 450$ psig $T \leq 190°F$

2) $P = 315 + 5.752\ e^{0.01666T}$ $T > 190°F$

Valid for first 3.9 EFPY

3) $P = 2385$ psig $T \geq 350°F$


MAXIMUM PORV SETPOINT (psig.)
3000
2500
2385
2000
1500
1000
500
200
100
150
200
250
300
350
400
RCS TEMPERATURE (°F)
190°F
(450 psig.)
2385 PSIG
FIXED PORV
SETPOINT
LTOP
ARMING POINT
350° F

## SEABROOK STATION

### Setpoint and Value Study Documentation Sheet

Setpoint/Value Description: The pressurizer spray pressure setpoint

Determined Setpoint/Value: 2260 psig*

Specific Instrument Usage: N/A

References/Sources:

Seabrook Station
Final Safety Analysis Report
Chapter 5, Table 5.4-10

PSNH Seabrook Station
Precautions, Limitations and Setpoints
for Nuclear Steam Supply Systems
Page 30, 3.B

Assumptions: N/A

Calculations: N/A

Note: *25 psi above setting of RC-PK-455A, Master Pressure Controller

NOTE: Seal injection flow should be maintained to all RCPs

PURPOSE: To ensure that seal cooling flow is continued even if RCPs are stopped

BASIS:

The effectiveness of the RCP Number 1 seal is not affected by pump rotation. To ensure continued performance of the seal, cool filtered water should be continuously supplied. The operator should not isolate the seal injection lines unless directed to in the procedures.

ACTIONS:

N/A

INSTRUMENTATION:

RCP seal injection flow indication to each RCP

CONTROL/EQUIPMENT:

N/A

KNOWLEDGE:

Seal injection flow response following a safety injection

PLANT-SPECIFIC INFORMATION:

Flow instruments are ranged 0-20 gpm. Seal injection flow is normally maintained between 8 and 13 gpm to each RCP. Minimum seal injection flow is 6 gpm and maximum seal injection flow is 20 gpm based on the RCP I.B.

STEP: Check If RCPs Should Be Stopped

PURPOSE: To trip RCPs if required conditions are satisfied

BASIS:

To minimize RCS mass loss which could lead to core uncovery and high PCTs if RCPs are allowed to run during a small break LOCA and subsequently trip.

ACTIONS:

- o Determine if at least one CCP is running
- o Determine if at least one SI pump is running
- o Determine if RCP Trip Parameter is less than 30°F subcooling based on core exit TCs
- o Stop all RCPs

INSTRUMENTATION:

- o CCP status indication
- o SI pump status indication
- o RCS subcooling based on core exit TCs
- o RCP status indication

CONTROL/EQUIPMENT:

Switches for RCPs

KNOWLEDGE:

- o Importance of RCP trip when required conditions are satisfied
- o This step is a continuous action step and is on the operator action summary page for the E-0 series of procedures.

PLANT-SPECIFIC INFORMATION:

The plant specific RCP trip criteria is determined from either of two criteria as follows:

o RCS subcooling less than 30°F based on core exit TC's

- OR -

o RCS pressure less than 1375 PSIG

Both of the above criteria provide adequate discrimination such that the RCPs are not tripped for secondary breaks and most SG tube rupture events but would be tripped for the small break LOCA events. The subcooling criteria will be used in the ERPs.

Subcooling is calculated based on the average of 27 incore TC's temperatures to compute an average core exit temperature. There are 29 TC inputs for each redundant TC train, however the highest and lowest TC temperature is deleted. Both average core exit temperature and subcooling are displayed on separate MCB instruments and are fed to the SPDS for each redundant train.

RCS pressure is measured by redundant pressure transmitters located outside containment. RCS pressure is displayed on separate MCB instruments in each train. RCS pressure is also fed to the SPDS for the subcooling calculation and the critical safety function status trees.

The following instrument ranges are provided:

| PARAMETER | ENGINEERING UNITS | INDICATION RANGE | NOTES |
|---|---|---|---|
| 1. Average Core Exit Temperature | °F | 0-2200 | one per train |
| 2. RCS Pressure | PSIG | 0-3000 | one per train |
| 3. RCS Subcooling | °F | 50° superheat to 300° subcooled | one per train |

See attached sheet.

SEABROOK STATION

Setpoint and Value Study Documentation Sheet

Setpoint/Value Description: Subcooling - Error

Determined Setpoint/Value: $\leq$ 30°F ($\pm$ 30°F error)

Specific Instrument Usage: TI-9424A Train A Range: -50° to 300°F
TI-9424B Train B

References/Sources: Telecon between Yankee Atomic Electric Co. (Mr. W. Fadden, I&C Engineer) and Westinghouse Electric Corporation (Design engineers for the subcooling indication package), 5/31/84.

Assumptions: N/A

Calculations: The 30°F subcooling error is a bounding error value. Typical error (actual) is approximately 18°F. Until formal calculations are provided by Westinghouse, the conservative 30°F error will be used.

115

STEP: Check If SG Pressure Boundary Is Intact

PURPOSE: To identify any faulted SGs (failure in secondary pressure boundary)

BASIS:

An uncontrolled SG pressure decrease or a completely depressurized (i.e., near containment or atmospheric pressure) SG indicates failure of the secondary pressure boundary. Isolation is to be performed using E-2, FAULTED STEAM GENERATOR ISOLATION.

ACTIONS:

- o Determine if no SG pressure is decreasing in an uncontrolled manner and no SG is completely depressurized
- o Transfer to E-2, FAULTED STEAM GENERATOR ISOLATION, step 1

INSTRUMENTATION:

Pressure indications for each SG (steamline)

CONTROL/EQUIPMENT:

N/A

KNOWLEDGE:

"Uncontrolled" means not under the control of the operator, and incapable of being controlled by the operator using available equipment.

PLANT-SPECIFIC INFORMATION:

SG pressure indications are ranged 0-1300 PSIG for both indicators and recorders. The recorders indicate recent pressure history and trend. The indicators show current pressure.

See attached sheet.

SEABROOK STATION

Setpoint and Value Study Documentation Sheet

Setpoint/Value Description: Main Steam Line Pressure Indication Error

Determined Setpoint/Value: Range: 0-1300 ± 50 psig, minor scale divisions 50 psig

Specific Instrument Usage: 1-FW-PI-514A, 515A, 516, 524A, 525A, 526, 534A, 535A, 536, 544A, 545A, 546A

References/Sources:

- o 9763-M-510000 Standard Instrument Schedule
- o W Protection System Setpoint Study NAH-2082, 12/7/82

Assumptions:

Calculations:

Error of Indication (EI) in % span

$$= \sqrt{(SCA + SD)^2 + (STE)^2 + (RCA + RD)^2 + (RTE)^2 + (IA)^2}$$

$$= \sqrt{(0.5 + 1.0)^2 + (0.5)^2 + (0.5 + 2.5)^2 + (0.5)^2 + (2.0)^2}$$

$$= \sqrt{2.25 + 0.25 + 9 + 0.25 + 4.0}$$

$$= \sqrt{15.75}$$

= 3.97 %

= rounding up = 4%

Error of Ind in. psig = Error in % span x span

= 4% x 1300 psig

= 52 psig

rounding down = 50 psig

(117)

STEP: Check If SG U-Tubes Are Intact

PURPOSE: To identify any ruptured SGs (failure in primary to secondary pressure boundary)

BASIS:

Abnormal condenser exhaust radiation or main steamline radiation indicates primary to secondary leakage. Optimal recovery in dealing with a steam generator tube rupture is provided in E-3, STEAM GENERATOR TUBE RUPTURE.

ACTIONS:

- o Determine if condenser effluent and main steamline radiation are normal
- o Transfer to E-3, STEAM GENERATOR TUBE RUPTURE

INSTRUMENTATION:

- o Condenser effluent radiation indication
- o Main steamline radiation indication for each steamline

CONTROL/EQUIPMENT:

N/A

KNOWLEDGE:

"Normal" means the value of a process parameter experienced during routine plant operations.

PLANT-SPECIFIC INFORMATION:

The condenser effluent monitor senses volatile radionuclides and is a good indication of a SG tube leak or rupture with the MSIVs open. The main steamline radiation monitors, one on each steamline, are located upstream of the MSIVs and the ASDVs. These radiation monitors are used to detect SG tube leakage or rupture and to ascertain which SG(s) is effected. The main steamline monitors remain unisolated.

STEP: Check If RCS Is Intact

PURPOSE: To identify any failure in the RCS pressure boundary into the containment

BASIS:

Abnormal containment radiation, pressure, or level is indicative of a high energy line break in containment. Since the SGs have been determined to be non-faulted in an earlier step, then the break must be in the reactor coolant system. For smaller size breaks containment pressure and level may not increase for a period of time; however, containment radiation would be apparent. Procedure E-1, LOSS OF REACTOR OR SECONDARY COOLANT, is used for breaks in the RCS.

ACTIONS:

- o Determine if containment radiation, pressure, and containment building level are normal
- o Transfer to E-1, LOSS OF REACTOR OR SECONDARY COOLANT, step 1

INSTRUMENTATION:

- o Containment radiation indication
- o Containment pressure indication
- o Containment building level indication

CONTROL/EQUIPMENT:

N/A

KNOWLEDGE:

"Normal" means the value of a process parameter experienced during routine plant operations.

PLANT-SPECIFIC INFORMATION:

N/A

STEP DESCRIPTION TABLE FOR E-0 STEP 25

STEP: Check If SI Flow Should Be Reduced

PURPOSE: To determine if conditions have been established which indicate that full ECCS flow is no longer required

BASIS:

Following SI actuation, RCS conditions may be restored to within acceptable limits for ECCS flow reduction to be allowed, particularly if the SI is spurious. Refer to document SI TERMINATION/REINITIATION in the Generic Issues section of the Executive Volume.

ACTIONS:

- o Determine if RCS subcooling based on core exit TCs is greater than 30°F
- o Determine if total feed flow to SGs is greater than 470 gpm
- o Determine if narrow range level in at least one SG is greater than 5%
- o Determine if RCS pressure is stable or increasing
- o Determine if PRZR level is greater than 5%
- o Try to stabilize RCS pressure with normal PRZR spray

INSTRUMENTATION:

- o RCS subcooling based on core exit TCs
- o Average core exit TCs temperature indication
- o EFW flow indication
- o SG narrow range level indication
- o RCS pressure indication
- o Pressurizer level indication

CONTROL/EQUIPMENT:

Controls for normal PRZR spray valves

KNOWLEDGE:

Use of PRZR spray to assist in restoring PRZR level.

PLANT-SPECIFIC INFORMATION:

See attached sheets.

SEABROOK STATION

Setpoint and Value Study Documentation Sheet

Setpoint/Value Description: Pressurizer Level

Determined Setpoint/Value: Range 0-100% $\pm$ 3.6% (Normal)

$\left.\begin{array}{l}\mp 41.6\% \\ + 4.4\%\end{array}\right]$ (MSLB)

Specific Instrument Usage: RC-LI-459A, -460A, -461A, RC-LR-459A

References/Sources:

- o 9763-M-510000 Standard Instrument Schedule
- o W Protection System Setpoint Study, NAH-2082, 12/7/82
- o Specification 170-5, Panel Mounted Indicators
- o RAI 420.23

Assumptions: Accident conditions after MSLB, normal pressure.

Calculations:

$$\text{Normal Error} = \pm\sqrt{\text{PMA}^2 + (\text{Loop Error})^2}$$

$$= \pm\sqrt{(2)^2 + (3)^2}$$

$$= \pm\sqrt{13}$$

$$= \pm 3.6\%$$

$$\text{Error}_{\text{MSLB}} = \text{Error}_{\text{normal}} + \text{EA} + \text{Ref. Leg Error}$$

$$= \pm 3.6\% \pm 15\% + 23\% = \begin{array}{l} + 41.6\% \\ + 4.4\% \end{array}$$

Where:

$$\text{Ref Leg Error} = \frac{R\Delta\rho R}{S(\rho_{f,cal} - \rho_{g,cal})}$$

(see page 1 of RAI 420.23, attached)

(21)

Assumptions: $R = S$

$T_{cal} = 120°F$

$T_{acc} = 375°F$

$V_{120} = .01620\ ft^3/lb,\ \rho_{120} = 61.73\ lb/ft^3$

$V_{375} = .01829\ ft^3/lb,\ \rho_{375} = 54.7\ lb/ft^3$

$V_{g,cal} = 0.16272\ ft^3/lb,\ \rho_{g,cal} = 6.145\ lb/ft^3$

$V_{f,cal} = 0.02669\ ft^3/lb,\ \rho_{f,cal} = 37.46\ lb/ft^3$

$$E = \frac{(61.73 - 54.7\ lb/ft^3)}{(37.46 - 6.145)}$$

$$= +22.5\% \sim +23\%$$

420.23
(7.2)

Describe how the effects of high temperatures in reference legs of steam generator and pressurizer water level measuring instruments subsequent to high energy breaks are evaluated and compensated for in determining setpoints. Identify and describe any modifications planned or taken in response to IEB 79-21. Also, describe the level measurement errors due to environmental temperature effects on other level instruments using reference legs.

RESPONSE:
5/83

The error in dp level measurement systems due to changes in fluid densities is:

$$E = \frac{R(\Delta\rho_R - \Delta\rho_g) - L(\Delta\rho_f - \Delta\rho_g)}{S(\rho_{f,cal} - \rho_{g,cal})} \times 100$$

where:

- $E$ = Error in % span
- $R$ = Height of reference leg water level above the variable leg tap
- $S$ = Span (distance between taps)
- $L$ = Water level above the variable tap
- $\rho g_{cal}$ = Vapor calibration density
- $\rho f_{cal}$ = Process fluid calibration density
- $\Delta\rho_R$ = Change in reference leg density from the calibration value
- $\Delta\rho_g$ = Change in vapor density from $\rho_{g,cal}$
- $\Delta\rho_f$ = Change in process fluid density from $\rho_{f,cal}$

Note: $\Delta\rho = \rho\ cal - \rho\ accident$

This error determination assumes that the reference leg and variable leg below the variable tap are at the same temperature and produce counteracting errors.

A. Effects of Post-Accident Conditions on Indicated Level

1. Reference Leg Heatup

If the process conditions are not affected by the accident, the error due to reference leg heatup is:

$$E = \frac{R\Delta\rho_R}{S(\rho_{f,cal} - \rho_{g,cal})}$$

A decrease in reference leg density will increase the indicated level.

STEP: Go to ES-1.1, SI TERMINATION, Step 1

PURPOSE: To direct the transition to the appropriate procedure for SI termination

BASIS:

ES-1.1 contains the appropriate SI termination actions and, therefore, the operator is instructed to transfer to this procedure.

ACTIONS:

Transfer to ES-1.1, SI TERMINATION, step 1

INSTRUMENTATION:

N/A

CONTROL/EQUIPMENT:

N/A

KNOWLEDGE:

N/A

PLANT-SPECIFIC INFORMATION:

N/A

STEP: Initiate Monitoring of Critical Safety Function Status Trees

PURPOSE: To initiate monitoring of the status trees

BASIS:

At this point in E-0, no transition to an Optimal Recovery Procedure has been made and SI termination criteria have not been met. The operator will remain in E-0 until either a transition to a recovery procedure is made or SI can be terminated. Monitoring the Critical Safety Function Status Trees will ensure that the plant remains in a safe condition while the operator remains in E-0. The basis for the placement of this instruction in Step 27 follows.

The operator is trained to monitor the Critical Safety Function Status Trees when a transition out of E-0 is made (see Users Guide). Since a transition out of E-0 is expected, the Critical Safety Function Status Trees are monitored soon after the reactor trip or safety injection. However, if the operator does not make a transition out of E-0 due to lack of appropriate symptoms, Step 27 gives explicit instruction to monitor the Status Trees while remaining in E-0. Placement of this instruction after the verification of automatic actions and the diagnostic sequence is due to various reasons. Verification of automatic actions ensures that plant equipment is operating properly. These steps are performed prior to monitoring the Status Trees since the proper operation of the safeguards equipment is the first means of preventing or correcting any challenges to the Critical Safety Functions. The diagnostic sequence can be performed fairly quickly and any transition to another Optimal Recovery Procedure would require that the Critical Safety Function Status Trees be monitored. Hence, the step to explicitly monitor the Status Trees in E-0 follows these actions. In addition, any extreme challenges to the Critical Safety Functions due to equipment failure are addressed by explicit transitions out of the immediate action steps in E-0.

ACTIONS:

Initiate monitoring of Critical Safety Function Status Trees

INSTRUMENTATION:

CONTROL/EQUIPMENT:

N/A

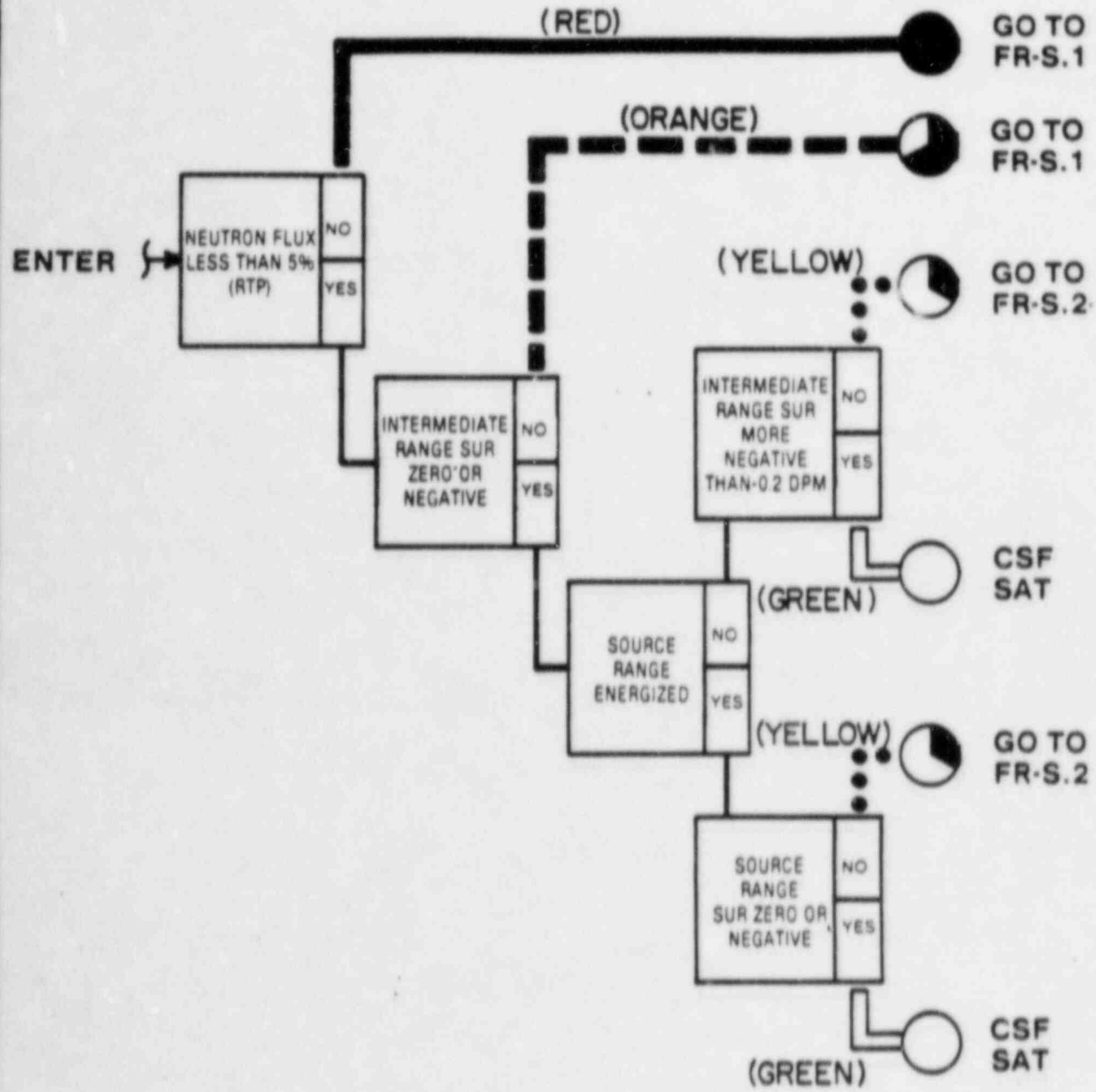
KNOWLEDGE:

PLANT-SPECIFIC INFORMATION:

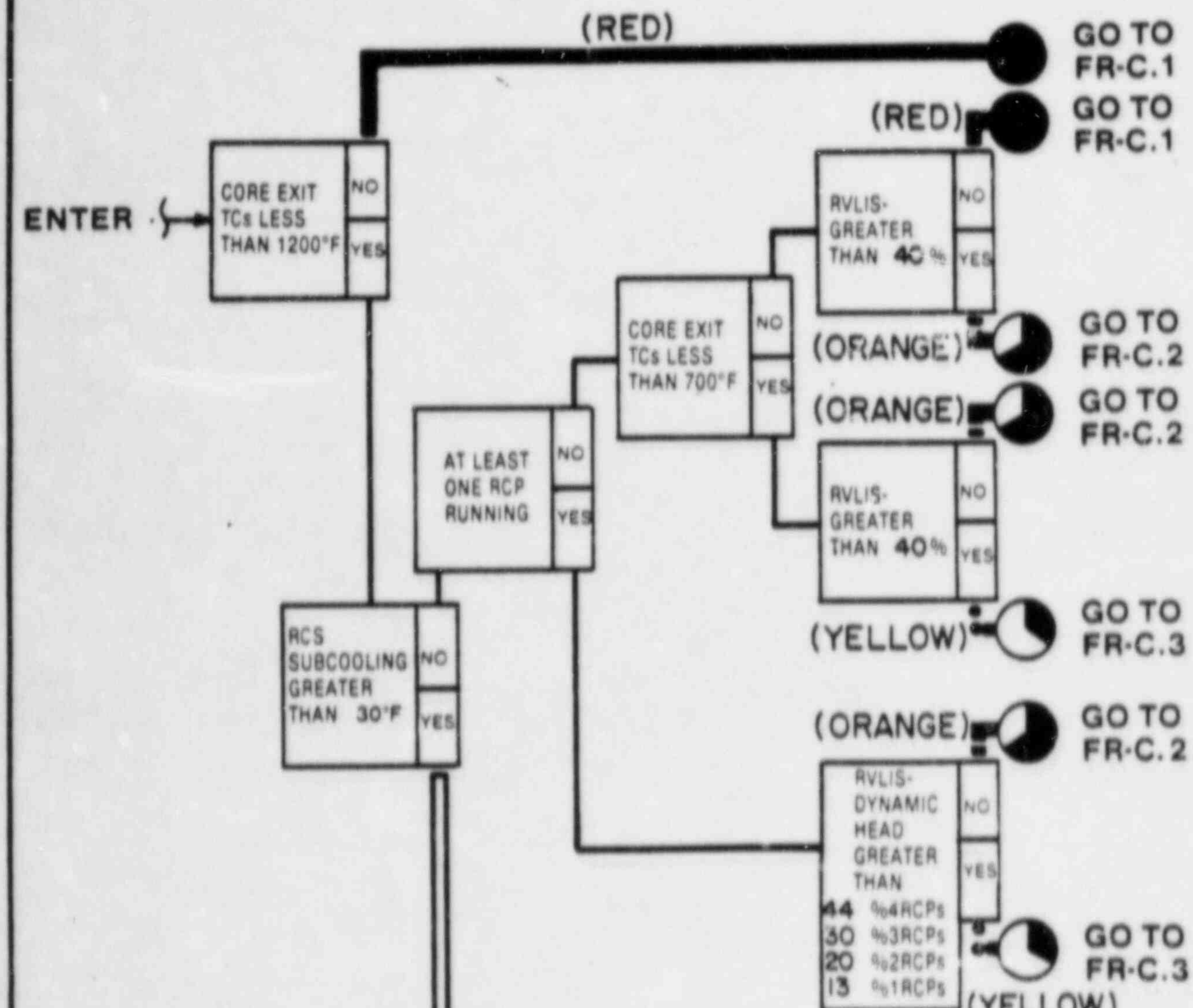
Critical Safety Function Status Trees can be monitored in two ways, ie; active video graphic displays and manually by the STA. Both of these methods were tested and validated during the Seabrook ERP Validation Program in October, 1983. All CSF Status Tree inputs have hard wired backup instruments on the MCB. Should the active video graphic displays (driven by the plant computer) be inoperable, the STA can manually determine the status of all critical safety functions.

The CSF Status Trees are provided for reference.

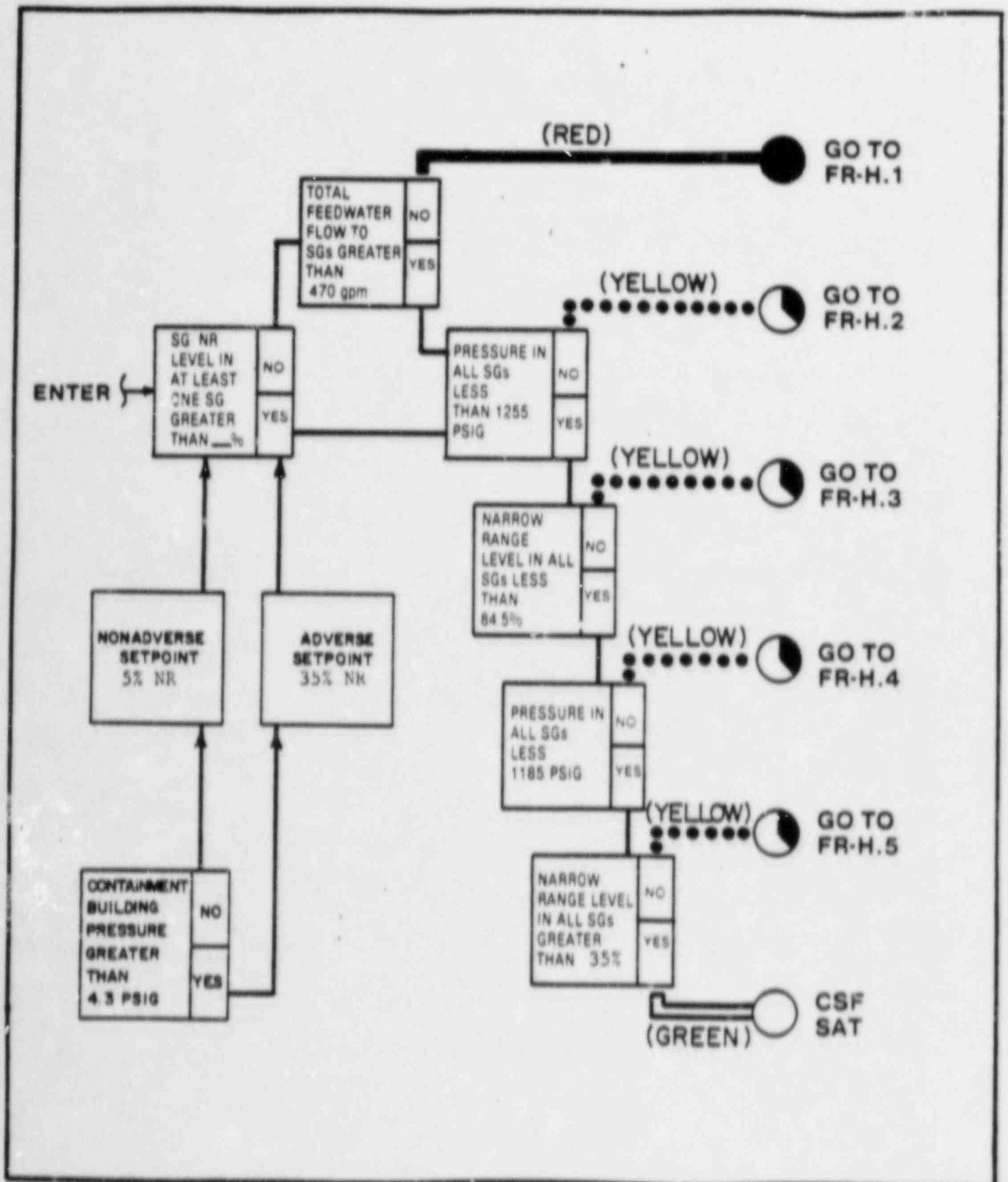
| Code: F-0.1 Rev. 1 Background Document | Symptom/Title SUBCRITICALITY STATUS TREE | Procedure No. Revision No./Date OS1350.1 00 / 06/05/84 |
|---|---|---|



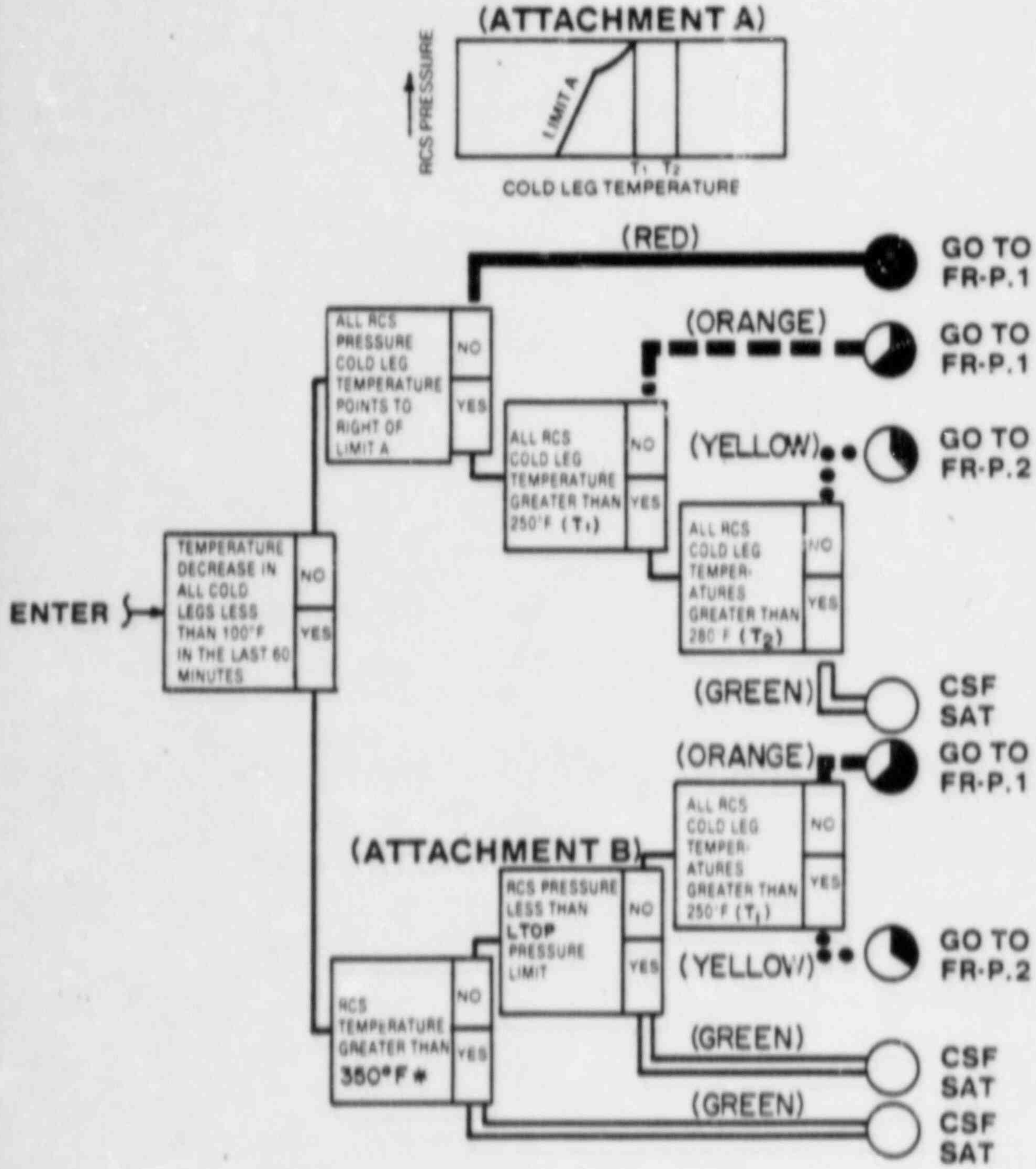
| CODE: | SYMPTOM/TITLE: | PROCEDURE NO. REVISION NO./DATE: |
|---|---|---|
| F-0.2 Rev. 1 Background Document | CORE COOLING STATUS TREE | OS1350.2 00 / 06/05/84 |



| CODE: | SYMPTOM/TITLE: | PROCEDURE NO. REVISION NO./DATE: |
|---|---|---|
| F-0.3<br>Rev. 1<br>Background<br>Document | HEAT SINK STATUS TREE | OS1350.3<br>00 / 06/05/84 |



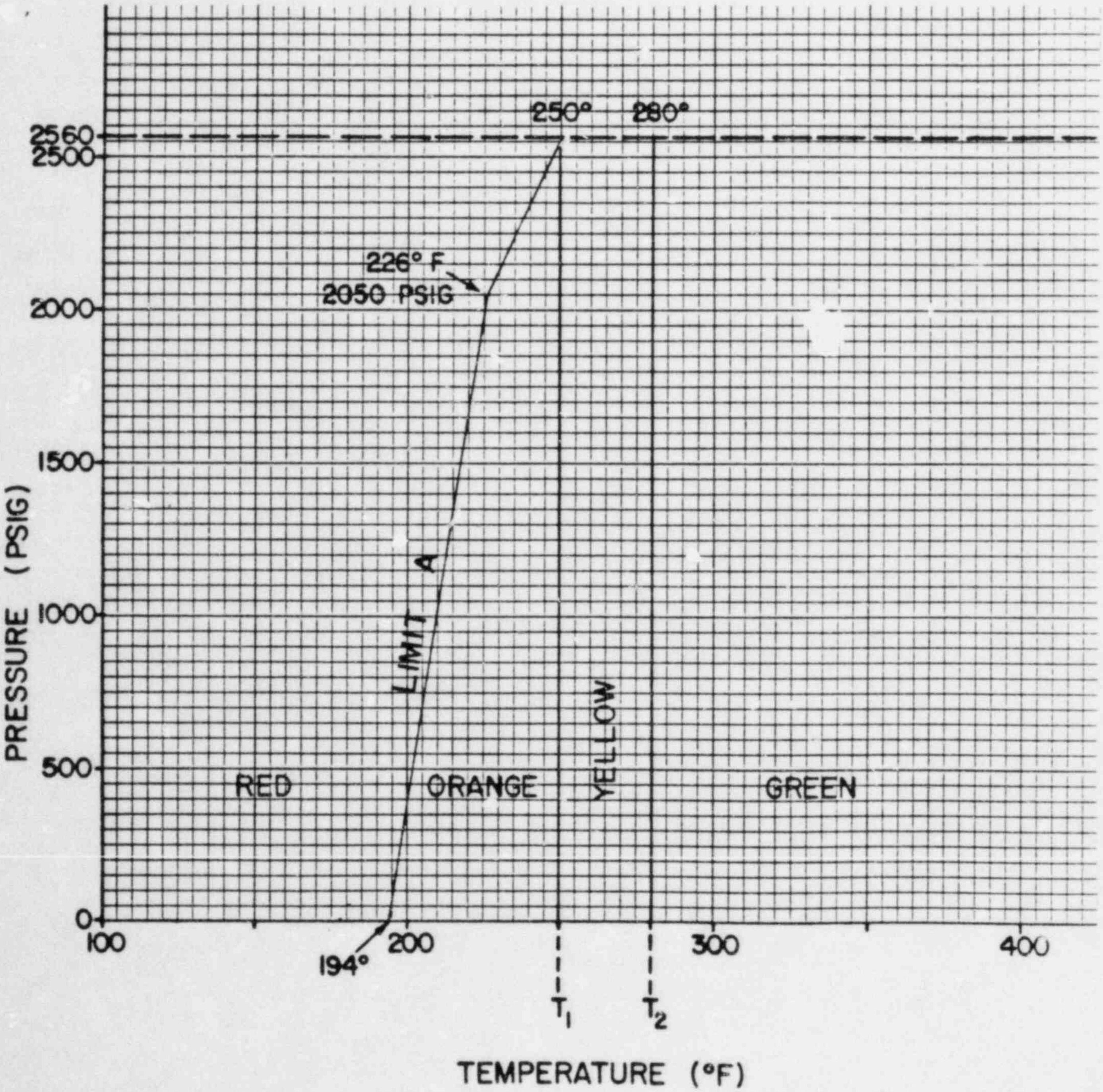
| CODE: | SYMPTOM/TITLE: | PROCEDURE NO. REVISION NO./DATE: |
|---|---|---|
| F-0.4 Rev. 1 Background Document | INTEGRITY STATUS TREE | OS1350.4 00 / 06/05/84 |

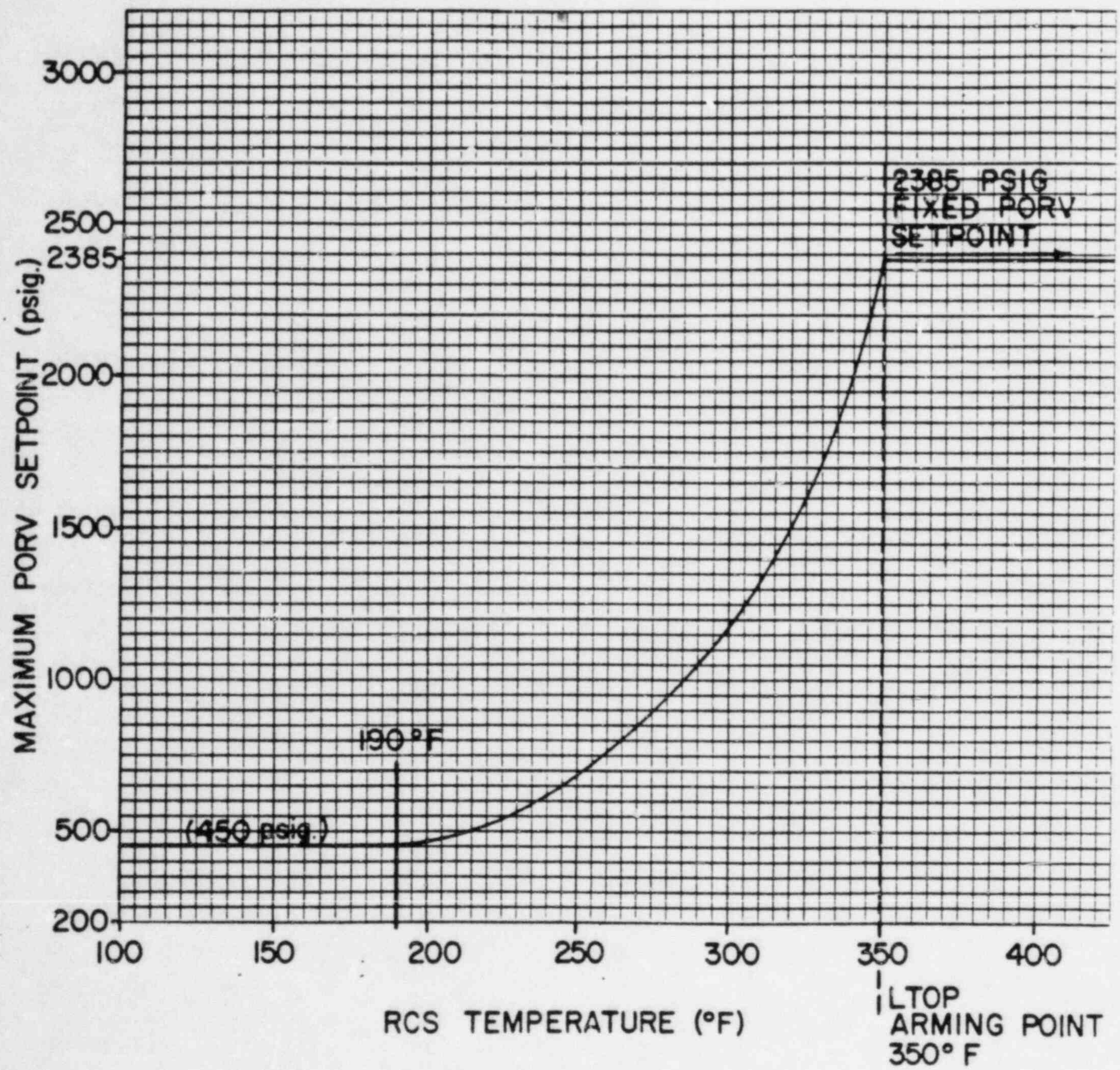



*ARMING BISTABLE SETPOINT

130

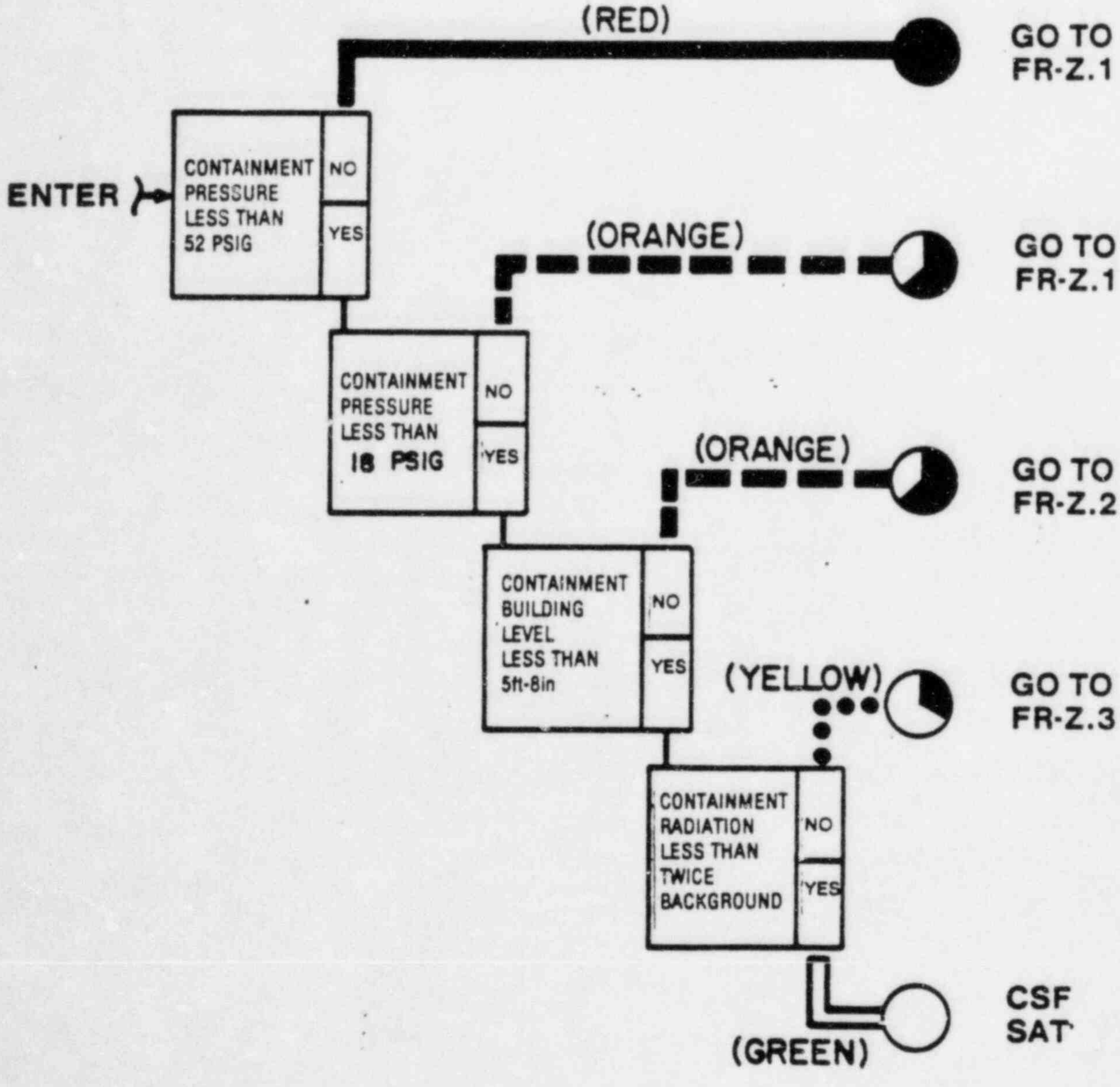
| | | |
|---|---|---|
| E-0 Background Document | PTS LIMITS CURVE (SEABROOK STATION) | 05/30/84 |



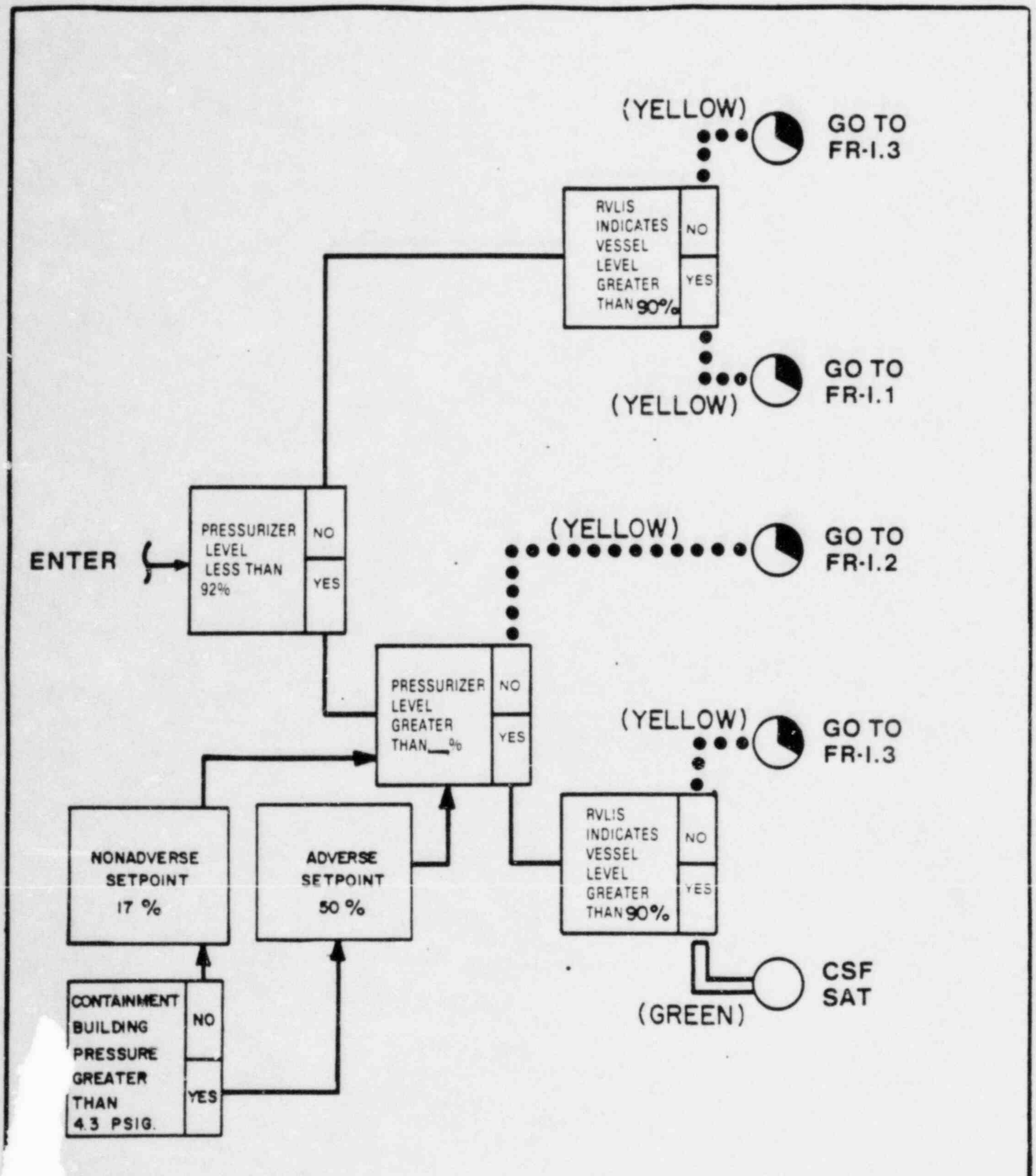


MAXIMUM PORV SETPOINT (psig.)
3000
2500
2385
2000
1500
1000
500
200
100
150
200
250
300
350
400
RCS TEMPERATURE (°F)
2385 PSIG
FIXED PORV
SETPOINT
190°F
(450 psig.)
LTOP
ARMING POINT
350° F

| CODE: | SYMPTOM/TITLE: | PROCEDURE NO. REVISION NO./DATE: |
|---|---|---|
| F-0.5 Rev. 1 Background Document | CONTAINMENT STATUS TREE | OS1350.5 00 / 06/05/84 |



| CODE: | SYMPTOM/TITLE: | PROCEDURE NO. REVISION NO./DATE: |
|---|---|---|
| F-0.6<br>Rev. 1<br>Background Document | INVENTORY STATUS TREE | OS1350.6<br>00 / 06/05/84 |



CAUTION: Commence CST makeup as early as possible to avoid low inventory problems.

PURPOSE: To alert the operator that CST level is decreasing and that makeup should commence as soon as possible to avoid low inventory problems during long term recovery actions

BASIS:

The CST is sized to allow four (4) hours at hot standby followed by a cooldown to the point of RHR operation. The CST has a nominal capacity of 400,000 gallons with a minimum required volume of 210,000 gallons in Modes 1, 2 and 3. This caution draws the operators attention to the fact that over the long term, ie; far beyond this point in E-0, CST makeup may be necessary to maintain adequate EFW pump NPSH and SG makeup. Starting CST makeup early eliminates the need to provide emergency makeup at a later time. The minimum volume for adequate EFW pump NPSH is approximately 10,000 gallons and is addressed in later recovery procedures where applicable.

ACTIONS:

Commence CST makeup

INSTRUMENTATION:

o CST level indication

CONTROL/EQUIPMENT:

N/A

KNOWLEDGE:

N/A

PLANT-SPECIFIC INFORMATION:

CST level is ranged 0-40 feet with a nominal capacity of 400,000 gallons. Therefore, level in feet x $10^4$ yields volume in gallons.

CST level can be ascertained by observing suction pressure on FI-PI-4252 and 4257.

See attached sheet.

## SEABROOK STATION

### Setpoint and Value Study Documentation Sheet

**Setpoint/Value Description:** CST Level

**Determined Setpoint/Value:** Range: LI 0-40 $\pm$ 1.5 ft
PI 0-40 $\pm$ 2.0 ft

**Specific Instrument Usage:** FW-PI-4252, 4257 (0-30 psig)
CO-LI-4079, 4096 (MCB) (0-40 ft $H_2O$)
Minor Grad 1 ft

**References/Sources:** 9763-M-510000, Standard Instrument Schedule

**Assumptions:** PI cal. at no flow Error = $\pm$ 3%

**Calculations:** LI Error = 40x $\pm$ .03 = $\pm$ 1.2 ft ~ $\pm$ 1.5 ft $H_2O$

PI Error = 30x $\pm$ .03 = $\pm$ 0.9 psi

$$\pm 0.9 \text{ psi} \times \frac{2.309 \text{ ft } H_2O}{\text{psi}} = \pm 2.1 \text{ ft} \sim \pm 2 \text{ ft } H_2O$$

Line losses at full flow = 4 FT $H_2O$

(136

STEP: Check SG Levels:

PURPOSE: To ensure adequate feed flow or SG inventory for secondary heat sink requirements

BASIS:

The minimum feed flow requirement satisfies the feed flow requirement of the Heat Sink Status Tree until level in at least one SG is restored into the narrow range. Narrow range level is reestablished in all SGs to maintain symmetric cooling of the RCS. The control range ensures adequate inventory with level readings on span. The transition to E-3, STEAM GENERATOR TUBE RUPTURE, responds to an increasing level which would be observed following a SGTR.

ACTIONS:

- o Determine if SG narrow range level greater than 5%
- o Determine if narrow range level in any SG increases in an uncontrolled manner
- o Maintain total feed flow greater than 470 gpm until narrow range level greater than 5% in at least one SG
- o Control feed flow to maintain narrow range level between 5% and 50%
- o Transfer to E-3, STEAM GENERATOR TUBE RUPTURE, step 1

INSTRUMENTATION:

- o SG narrow range level indication for each SG
- o EFW flow indication
- o EFW flow control valves position indication for each SG

CONTROL/EQUIPMENT:

EFW flow control valves switches

KNOWLEDGE:

- o "Level increase in an uncontrolled manner" means that the operator cannot control level using available equipment, i.e., level continues to rise even when all feed flow valves to that SG are fully closed.
- o This step is a continuous action step.

## STEP DESCRIPTION TABLE FOR E-0 STEP 29

**STEP:** Check Main Steamline Radiation - NORMAL

**PURPOSE:** To identify any ruptured (failure in primary to second' ry pressure boundary) SGs

**BASIS:**

Abnormal radiation in a steam generator indicates primary to secondary leakage. Since the condenser exhaust and blowdown lines may have been isolated at the initiation of the transient, it may be necessary to check each steam generator at this time. Optimal recovery in dealing with a steam generator tube rupture is provided in E-3, STEAM GENERATOR TUBE RUPTURE.

**ACTIONS:**

- o Determine if secondary radiation level is normal
- o Transfer to E-3, STEAM GENERATOR TUBE RUPTURE, step 1

**INSTRUMENTATION:**

Main steamline radiation monitors, one on each steamline

**CONTROL/EQUIPMENT:**

N/A

**KNOWLEDGE:**

"Normal" means the value of a process parameter experienced during routine plant operations.

**PLANT-SPECIFIC INFORMATION:**

The main steamline radiation monitors, one for each steamline, are located upstream of the main steamline isolation valves and the atmospheric steam dump valves. These monitors are provided to detect SG tube leakage or rupture and always remain unisolated.

STEP: Check Auxiliary Building Radiation - NORMAL USING RDMS

PURPOSE: To ensure that there is no primary leakage into the auxilary building

BASIS:

During the initiation of the transient, there should be no abnormal indications in the auxiliary building. If abnormal radiation levels exist, the operating crew should attempt to identify the cause of the abnormal conditions. If the cause is determined to be a loss of RCS inventory outside containment, then the operator should go to ECA-1.2, LOCA OUTSIDE CONTAINMENT, to try to terminate the leakage.

ACTIONS:

- o Determine if auxiliary building radiation is normal
- o Determine if cause of abnormal radiation is loss of RCS inventory outside containment
- o Evaluate cause of abnormal radiation conditions
- o Transfer to ECA-1.2, LOCA OUTSIDE CONTAINMENT, step 1.

INSTRUMENTATION:

Auxiliary building area radiation monitor display on RDMS

CONTROL/EQUIPMENT:

N/A

KNOWLEDGE:

- o Determination of a loss of RCS inventory outside containment
- o "Normal" means the value of a process parameter experienced during routine plant operations.

PLANT-SPECIFIC INFORMATION:

The applicable radiation monitors are scanned by the RDMS:

## AUXILIARY BUILDING - AREA MONITORS

| INSTRUMENT TAG NO. RE- | DESCRIPTION | DETECTOR TYPE | DETECTOR BACK-GRD.< mr/hr | RANGE LOW-HIGH mr/hr |
|---|---|---|---|---|
| 6537 | Sampling Room | GM | 2.5 | $10^{-1}$ - $10^{4}$ |
| 6538, 6539 | RHR Pump Area | GM | > 100 | $10^{-1}$ - $10^{4}$ |
| 6540 | Volume Control Tank Area | Ion Chamber | 8 x $10^{4}$ | $10^{1}$ - $10^{7}$ |
| 6541 | Lower Level | GM | 2.5 | $10^{-1}$ - $10^{4}$ |
| 6542 | Lower Level | GM | 20 | $10^{-1}$ - $10^{4}$ |
| 6543 | Entrance | GM | > 100 | $10^{-1}$ - $10^{4}$ |
| 6544 | Entrance | GM | 2.5 | $10^{-1}$ - $10^{4}$ |
| 6545, 6546 6547 | Charging Pump Rooms | GM | 110 | $10^{-1}$ - $10^{4}$ |
| 6508-1, 2 | PAB-HRAM | Ion Chamber | > 100 | $10^{-2}$ - $10^{4}$ r/ |
| 6563-1, 2 | PAB-HRAM | Ion Chamber | > 100 | $10^{-2}$ - $10^{4}$ r/ |
| 6517-1, 2 | RHR - Pump Vault HRAM | Ion Chamber | > 100 | $10^{-2}$ - $10^{4}$ r/ |
| 6518 | Spent Fuel - HRAM | Ion Chamber | 2.5 | $10^{-2}$ - $10^{4}$ r/ |

## AIRBORNE RADIATION MONITORS

| INSTRUMENT TAG NO. RE- | DESCRIPTION | DETECTOR TYPE | REFERENCE ISOTOPE | DETECTOR BACK-GRD.< mr/hr | RANGE LOW-HIGH µCi/cc |
|---|---|---|---|---|---|
| 6533-1 | Plant Vent - PIG (Radiogas) | Beta | Xe133 | 2.5 | $10^{-7}$ - $10^{-3}$ |
| 6533-2 | Plant Vent - PIG (Particulate) | Beta | I131, Cs137 | 2.5 | $10^{-11}$ - $10^{-5}$ |
| 6533-3 | Plant Vent - PIG (Iodine) | Beta | I131 | 2.5 | $10^{-11}$ - $10^{-6}$ |
| 6528-1 | Plant Vent - WRGM (Low Range) | Beta | Xe133, Kr85 | 2.5 | $10^{-7}$ - $10^{-1}$ |
| 6528-2 | Plant Vent - WRGM (Mid Range) | Solid State | Xe133, Kr85 | 2.5 | $10^{-3}$ - $10^{3}$ |
| 6528-3 | Plant Vent - WRGM (Hi Range) | Solid State | Xe133, Kr85 | 2.5 | $10^{-1}$ - $10^{5}$ |

## AIRBORNE RADIATION MONITORS (Cont)

| INSTRUMENT TAG NO. RE- | DESCRIPTION | DETECTOR TYPE | REFERENCE ISOTOPE | DETECTOR BACK-GRD.< mr/hr | RANGE LOW-HIGH μCi/cc |
|---|---|---|---|---|---|
| 6530-1 | Plant Vent - Spectral Cor. Mon. | GM | $Xe^{133}$, $Kr^{85}$ | 2.5 | $10^{-1}$ - $10^{4}$ mr/hr |
| 6530-2 | Plant Vent - Spectral Cor. Mon. | Ion Chamber | $Xe^{133}$, $Kr^{85}$ | 2.5 | $10^{2}$ - $10^{7}$ mr/hr |
| 6531-1 | WPB Air Particulate | Beta | $I^{131}$, $CS^{137}$ | 2.5 | $10^{-11}$ - $10^{-7}$ |
| 6531-2 | WPB Radiogas | Beta | Xe133 | 2.5 | $10^{-7}$ - $10^{-3}$ |
| 6532-1 | PAB Air Particulate | Beta | $I^{131}$, $CS^{137}$ | 2.5 | $10^{-11}$ - $10^{-7}$ |
| 6532-2 | PAB Radiogas | Beta | Xe133 | 2.5 | $10^{-7}$ - $10^{-3}$ |

## AIRBORNE RADIATION MONITORS - DUCT MOUNTED

| INSTRUMENT TAG NO. RE- | DESCRIPTION | DETECTOR TYPE | BACK-GRD.< mr/hr | RANGE LOW-HIGH CPM |
|---|---|---|---|---|
| 6506A, B (1 RM) | CTL Rm East Air Intake | GM | 0.5 | $10^{1}$ - $10^{6}$ |
| 6506A, B (2 RM) | CTL Rm East Air Intake | GM | 0.5 | $10^{1}$ - $10^{6}$ |
| 6507A, B (1 RM) | CTL Rm East Air Intake | GM | 0.5 | $10^{1}$ - $10^{6}$ |
| 6507A, B (2 RM) | CTL Rm East Air Intake | GM | 0.5 | $10^{1}$ - $10^{6}$ |
| | Fuel Storage Building | | | |
| 6562 | FAH-Fuel Stor Bldg Exh | GM | 0.5 | $10^{1}$ - $10^{6}$ |
| | Containment Enclosure | | | |
| 6566 | EAH-Contn Encl Emerg Exh | GM | 0.5 | $10^{1}$ - $10^{6}$ |
| | Primary Auxiliary Building | | | |
| 6567 | PAB-Misc Ventilation | GM | 2.5 | $10^{1}$ - $10^{6}$ |
| 6568 | PAB-Contn Enclosure | GM | 2.5 | $10^{1}$ - $10^{6}$ |

STEP DESCRIPTION TABLE FOR E-0 STEP 31

STEP: Check PRT Conditions - NORMAL

PURPOSE: To check if there is any leakage into the PRT

BASIS:

Leakage into the PRT may come from various sources (e.g., seal return, valve stem leak-off). Evaluating the cause of any abnormal PRT conditions may assist the operator in the diagnosis of the plant fault (e.g., a leaking PORV).

ACTIONS:

o Determine if PRT conditions are normal
o Evaluate cause of abnormal conditions

INSTRUMENTATION:

o PRT level indication
o PRT temperature indication
o PRT pressure indication
o Safety or relief valve tailpipe temperatures

CONTROL/EQUIPMENT:

N/A

KNOWLEDGE:

o Flow paths that enter the PRT
o "Normal" means the value of a process parameter experienced during routine plant operations.

PLANT-SPECIFIC INFORMATION:

PRT inputs include the following:

o Pressurizer safety valves (2485 psig)
o Pressurizer PORVs (450 psig to 2385 psig)
o RHR suction line relief valves (450 psig)
o Letdown line relief (600 psig)
o RCP seal return line relief (150 psig)
o Reactor vessel head vent (manual)

CAUTION: If offsite power is lost after SI reset, manual action may be required to restart safeguards equipment.

PURPOSE: To alert the operator of a possible configuration which would not provide automatic start of safeguards equipment upon loss of offsite power

BASIS:

With the SI signal reset, no further automatic signal will be generated to restart safeguards equipment. Normal sequencing of safeguards loads onto the emergency bus after diesel-generator startup will not occur. However, a LOP without SI sequencer actuation should occur.

ACTIONS:

Determine if offsite power is lost after SI is reset

INSTRUMENTATION:

N/A

CONTROL/EQUIPMENT:

N/A

KNOWLEDGE:

The operator would 'reset' the sequencer after automatic loading and restart safeguards equipment as necessary.

PLANT-SPECIFIC INFORMATION:

N/A

STEP: Reset SI

PURPOSE: To utilize the reset function which is part of the safeguards actuation logic such that equipment can be realigned

BASIS:

In order to realign safeguards equipment, a deliberate action must be taken to reset the SI signal.

ACTIONS:

Reset SI

INSTRUMENTATION:

SI signal indication

CONTROL/EQUIPMENT:

SI reset switch

KNOWLEDGE:

N/A

PLANT-SPECIFIC INFORMATION:

N/A

STEP: Reset Containment Isolation Phase A And Phase B

PURPOSE: To remove the "locked-in" signal such that equipment can be realigned

BASIS:

This part of the automatic logic requires a deliberate operator action to remove the "close" signal. No valve will reposition upon actuation of the resets, but separate control actions will subsequently open the valves.

ACTIONS:

o Reset Containment Isolation Phase A
o Reset Containment Isolation Phase B

INSTRUMENTATION:

o Containment Phase A indication
o Containment Phase B indication

CONTROL/EQUIPMENT:

o Containment Phase A reset switch
o Containment Phase B reset switch

KNOWLEDGE:

N/A

PLANT-SPECIFIC INFORMATION:

N/A

STEP: Establish Instrument Air To Containment

PURPOSE: To restore a sustained, compressed air supply to allow control of air-operated equipment.

BASIS:

Two separate instrument air supplies are provided, one for equipment inside containment and one for equipment outside containment. Both systems have air accumulators to provide air storage should compressors not be running; however, at least one compressor in each system must be operating to provide a continuous air supply. Compressors in both systems can be powered from emergency power.

Although no ESF components require air to function or perform their function, air is required to implement certain desired recovery actions such as restoration of charging and letdown.

ACTIONS:

- Realign valves to restore compressor cooling
- Start SCCW pump
- Start air compressors as necessary

INSTRUMENTATION:

- Containment isolation valve position indications
- Air pressure indications
- Compressor status indications

CONTROL/EQUIPMENT:

- SCCW pump control switch
- Containment isolation valve switches
- Air compressor control switches

KNOWLEDGE:

N/A

PLANT-SPECIFIC INFORMATION:

N/A

CAUTION: RCS pressure should be monitored. If RCS pressure decreases to less than 270 psig, the RHR pumps must be manually restarted to supply water to the RCS

PURPOSE: To alert the operator to possible manual action requirements as a result of his actions in the following step

BASIS:

RHR pumps should be stopped if RCS pressure is above their shutoff head, since they will not be delivering flow. However, if RCS pressure subsequently decreases to less than 270 psig, then the pumps will have to be restarted manually since no automatic signal is available.

ACTIONS:

Determine if RCS pressure decreases to less than 270 psig

INSTRUMENTATION:

RCS pressure indication

CONTROL/EQUIPMENT:

N/A

KNOWLEDGE:

N/A

PLANT-SPECIFIC INFORMATION:

Since the RHR pump shutoff head has previously been determined to be 200 PSIG and pressure error is $\pm$ 70 PSIG, the operator is instructed to start the RHR pumps @ 200 + 70 = 270 PSIG.

See attached sheet.

**STEP:** Check If RHR Pumps Should Be Stopped:

**PURPOSE:** To stop the RHR pumps if RCS pressure is sufficiently high to prevent any injection flow

**BASIS:**

RHR pumps can only deliver flow against fairly low RCS pressures. At higher pressures, they inject no water and are pumping water around a small closed loop. The pumps are stopped to prevent potential damage due to heat up.

**ACTIONS:**

- Determine if RCS pressure is greater than 270 psig
- Determine if RCS pressure is stable or increasing
- Transfer to E-1, LOSS OF REACTOR OR SECONDARY COOLANT, step 1
- Stop RHR pumps and place in standby

**INSTRUMENTATION:**

- RCS pressure indication
- RHR pumps status indications

**CONTROL/EQUIPMENT:**

RHR pumps switches

**KNOWLEDGE:**

N/A

**PLANT-SPECIFIC INFORMATION:**

STEP DESCRIPTION TABLE FOR E-0     STEP 36

STEP: Check If Emergency Diesel Generators Should Be Stopped?

PURPOSE: To stop emergency diesel generators if they have started and are running unloaded

BASIS:

Manufacturers typically recommend that diesels not be run extensively unless they are carrying load. Diesels should auto-start on an SI signal, but will not load if offsite power is available. If DGs are supplying the emergency busses, then possibly some additional equipment should be loaded to aid the recovery process.

When the diesel generators are stopped, they are placed in standby to be ready to start either manually or automatically

ACTIONS:

- o Determine if ac emergency busses are energized by offsite power
- o Determine if offsite power cannot be restored
- o Try to restore offsite power to ac emergency busses
- o Load equipment on ac emergency busses
- o Stop any unloaded diesel generator and reset for auto start
- o Isolate SW to DCCW

INSTRUMENTATION:

- o AC emergency busses voltage indication
- o Offsite power status indication
- o Diesel generator status indication
- o Status indication for plant specific equipment to be loaded on ac emergency busses

CONTROL/EQUIPMENT:

- o Diesel generators switches
- o Breaker controls for additional equipment to be loaded on ac emergency busses, if applicable

KNOWLEDGE:

Continuous diesel-generator load rating

PLANT-SPECIFIC INFORMATION:

During normal plant operations, all of the emergency diesel generators are in standby--ready for automatic start and operation in an emergency. There are two conditions that start the emergency diesel generators and load the emergency bus with essential equipment.

The first condition is a loss of offsite power (referred to as LOP). In this case, the diesel engine is started by a signal from the EPS. Once the generator is up to rated speed and voltage, the diesel generator output breaker is closed, and the emergency bus is loaded by the EPS. The emergency power sequencer, in nine sequential steps, energizes loads necessary for the safe shutdown of the reactor.

The second condition is a combination of a safety injection signal coincident with a loss of offsite power (referred to as SI/LOP). The emergency 4.16 Kv AC buses are stripped (loadshed) by undervoltage trips, and the EPS is energized. The emergency diesel generator is started by the safety injected signal. The emergency power sequencer then energizes safety related loads necessary for a reactor shutdown with a safety injection signal present.

A third condition, a safety injection signal without the coincidence loss of power, will also start the emergency diesel generator. The generator is brought to speed (frequency) and voltage, but the generator input supply breaker is not closed. The generator will idle in the condition until a subsequent loss of power occurs, or the safety injection signal is reset and the diesel generator is manually shutdown. During this situation, the EPS is not activated.

It is unlikely that additional equipment would have to be loaded onto the emergency busses. However, if it is necessary, the operators know that the continuous load rating of each diesel generator is 6083 KW. The post-accident monitoring package consists of the following MCB instruments:

- DG Current (amps)
- DG Voltage (volts)
- Frequency (HZ)
- Power (KW)

STEP DESCRIPTION TABLE FOR E-0 STEP 37

STEP: Return to Step 19

PURPOSE: To continue trying to identify the appropriate Optimal Recovery Procedure

BASIS:

The operator is instructed to remain in E-0 until either a transition is made to a recovery procedure or SI can be terminated. Step 19 is after the verification of automatic action steps and is the beginning of the diagnostic sequence.

ACTIONS:

Return to Step 19

INSTRUMENTATION:

N/A

CONTROL/EQUIPMENT:

N/A

KNOWLEDGE:

N/A

PLANT-SPECIFIC INFORMATION:

N/A

- END -

PART (2)

RESPONSES TO APPENDICES A THROUGH D

APPENDIX

PART A

HUMAN FACTORS ENGINEERING IN-PROGRESS AUDIT

OF THE DETAILED CONTROL ROOM DESIGN REVIEW

FOR

PUBLIC SERVICE OF NEW HAMPSHIRE

SEABROOK STATION

Part A - This part describes those features or components that could not be evaluated by the review team. These items must be reviewed and evaluated by the applicant. Any identified HEDs and corrective actions selected must be reported to the NRC at least 120 days PTLF and discrepancies corrected PTLF or on a schedule approved by the NRC.

Licensee Response

Many of the features or components that could not be evaluated by the NRC review team will not be available for review by the Licensee review team until near to or after loading fuel. Our schedule for review of these features or components and correction of any discrepancies is listed for your review and concurrence following each feature below.

A1.0 CONTROL ROOM WORKSPACE

A. Control room furnishings were not installed. The adequacy of furnishings, obstacles to operator movement and presence of unnecessary furnishings and equipment could not be evaluated.

B. The Control Room environment during operations could not be evaluated.

C. Operator protective equipment and emergency equipment storage facilities could not be evaluated.

D. Document organization and storage provisions in the Control Room and at the Remote Shutdown Panel were not in final form and could not be evaluated.

E. Compatibility of emergency gear with operators' needs to perform operations while wearing protective equipment could not be evaluated.

Licensee Response

With the exception of B, these features and components will be reviewed at least 120 days PTLF. Any discrepancies discovered will be evaluated and prioritized in the same manner that all HEDs have been evaluated; and a schedule submitted for NRC approval. B will be evaluated during plant operation. Any discrepancies will be evaluated and prioritized, and a schedule submitted for NRC approval.

A2.0 COMMUNICATIONS

Communications equipment was not installed in final form and could not be evaluated.

Licensee Response

Communication equipment is not yet completely installed. It will be reviewed 120 days PTLF, discrepancies evaluated and prioritized, and a schedule submitted for NRC approval.

A3.0 ANNUNCIATORS

- o Unclear how annunciator system is integrated into procedures
- o Font size is different among hardwired tiles, status panel tiles, inoperative status tiles
- o Light test/bulb replacement

o Color coding

o Clear signal audibility/run out-time

Licensee Response

The Annunciator System, both Video Alarm and Hardwired, has been evaluated, including the items listed above. All HEDs have been evaluated and prioritized, and a schedule developed. This information is included as a part of this submittal.

A5.0 VISUAL DISPLAYS

The SPDS system was not ready to be evaluated.

Licensee Response

A static review of the SPDS has been done. No HEDs were found. An extensive validation and verification was performed of the whole Seabrook control board, including the SPDS. Observations of the use of the SPDS were made at the time. Video tapes of the process will be reviewed to complete the evaluation. Up to this time, no HEDs have been found in either the static or the dynamic review of the SPDS.

A7.0 PROCESS COMPUTERS

The status of the computer system was not complete and could not be evaluated. A few specific items are:

o Color coordination with Seabrook standard

o Limited character space on CRT screen may affect line text comprehension

o Coordination with SPDS

o Trending capability vs panel recorders

Licensee Response

The Process Computer has been evaluated, including the items listed above. All HEDs have been evaluated and prioritized, and a schedule developed. This information is included as a part of this submittal.

(156)

APPENDIX

PART B

HUMAN FACTORS ENGINEERING IN-PROGRESS AUDIT

OF THE DETAILED CONTROL ROOM DESIGN REVIEW

FOR

PUBLIC SERVICE OF NEW HAMPSHIRE

SEABROOK STATION

Part B - This part contains a list of NRC HED numbers and Seabrook report HED numbers for which the resolution and assigned importance are acceptable and the implementation schedule is acceptable as follows: Schedule A, B - complete PTLF, Schedule C - complete prior to start-up after first refueling outage, Schedule E - no corrective action is necessary, NA - not assigned by applicant.

Licensee Response

The schedule as defined above is acceptable to us for the following HEDs. (This list is the same as the one included in the NRC Appendix Part B).

| NRC HED NO. | SEABROOK HED NO. | PRIORITY SCHEDULE |
|---|---|---|
| B1.0 CONTROL ROOM WORKSPACE | | |
| 1.1 | VI.K.1 | 3E |
| 1.2 | V.A.5 | 3E |
| 1.3 | VI.D.14 | 2B |
| 1.4 | V.G. | 3A |
| 1.5 | V.K. | 3C |
| B3.0 ANNUNCIATOR WARNING SYSTEMS | | |
| 3.1 | VI.C.17 | 2B |
| 3.2 | V.D.4 | 3A |
| 3.5 | VI.C.2.1 | 3E |
| 3.6 | V.M.3 | 1A |
| 3.7 | VI.F.10 | 3B |
| 3.9 | V.D.2 | 3B |
| 3.10 | V.A.1 | 2B |
| 3.11 | V.D.1 | 2B |

| NRC HED NO. | SEABROOK HED NO. | PRIORITY SCHEDULE |
|---|---|---|
| **B4.0 CONTROLS** | | |
| 4.1 | VI.G.14 | 3A |
| 4.2 | VI.G.13 | 3A |
| 4.3 | VI.G.12 | 3E |
| 4.5 | VI.B.12 | 2A |
| 4.6 | VI.E.21 | 3E |
| 4.7 | V.I.4 | 2A |
| 4.10 | V.M.2 | 2E |
| 4.11 | VI.A.12 | 1A |
| 4.12 | VI.A.13 | 1A |
| 4.13 | VI.C.9 | 2C |
| 4.14 | V.L.4 | 3E |
| 4.15 | VI.I.1 | 3A |
| 4.16 | VI.G.7 | 1A |
| 4.18 | V.I.20 | 1A |
| 4.19 | V.I.3 | 3B |
| 4.20 | V.L.3 | 2B |
| 4.21 | V.N | 2B |
| 4.22 | VI.E.78 | 3E |
| **B5.0 VISUAL DISPLAYS** | | |
| 5.2 | VI.I.5 | 3E |
| 5.3 | VI.K.7 | 3C |
| 5.6 | VI.C.10 | 1A |
| 5.13 | VI.G.18 | 3B |
| 5.16 | VI.K.6 | 3B |
| 5.17 | VI.C.16 | 3E |
| 5.18 | V.J.5 | 3B |
| 5.19 | VI.C.5 | 1B |
| 5.20 | VI.G.8 | 3E |

| NRC HED NO. | SEABROOK HED NO. | PRIORITY SCHEDULE |
|---|---|---|
| 5.21 | VI.B.9 | NA |
| 5.22 | V.G.3 | 2B |
| 5.25 | VI.D.17 | 2C |
| 5.27 | V.O. | 2B |
| 5.28 | V.J.1 | 3A |
| 5.30 | V.A.2 | 3E |
| 5.31 | VI.I.3 | 3E |
| 5.32 | VI.D.18 | 3A |
| 5.35 | VI.A.11 | 1A |
| 5.36 | VI.G.5 | 2B |
| 5.37 | VI.F.7 | 3A |
| 5.38 | VI.E.22 | 3E |
| 5.39 | VI.E.13 | 3A |
| 5.40 | VI.D.16 | 1A |
| 5.41 | V.P | 1A |
| 5.42 | VI.B.10 | 3E |
| 5.43 | VI.G.6 | 3E |
| 5.44 | V.G.2 | (a) 3B |
| | | (b) 3E |
| 5.45 | VI.A.18 | 1B |
| 5.46 | VI.J.3 | 3E |
| 5.47 | V.M.1 | 3E |
| 5.48 | VI.C.19 | 1B |
| 5.49 | VI.A.7 | NA |
| 5.50 | VI.G.17 | 1A |
| 5.51 | VI.K.2 | 3E |
| 5.52 | VI.D.15 | 1A |
| 5.53 | VI.E.6 | 3A |
| 5.54 | VI.E.16 | 3A |
| 5.55 | VI.F.6 | 3A |
| 5.56 | VI.F.9 | 3A |
| 5.57 | VI.G.9 | 3E |

| NRC HED NO. | SEABROOK HED NO. | PRIORITY SCHEDULE |
|---|---|---|
| **B5.0 VISUAL DISPLAYS (Cont'd)** | | |
| 5.58 | VI.K.3 | 3E |
| 5.59 | VI.C.14 | 3E |
| 5.60 | VI.D.7 | 2A |
| **B6.0 LABELS AND LOCATION AIDS** | | |
| 6.1 | VI.K.11 | 3A |
| 6.2 | VI.K.9 | 3A |
| 6.3 | VI.J.1 | 1B |
| 6.5 | VI.I.6 | 3E |
| 6.6 | VI.G.21 | 3A |
| 6.7 | VI.G.16 | 2A |
| 6.8 | VI.G.4 | 3A |
| 6.9 | VI.E.14 | 2A |
| 6.10 | VI.E.4 | 2A |
| 6.11 | VI.C.13 | 2B |
| 6.13 | V.J.2 | 2B |
| 6.14 | V.F.1 | 3A |
| 6.16 | VI.D.6 | 3E |
| 6.17 | VI.I.4 | 1A |
| 6.18 | VI.C.15 | 1A |
| 6.19 | VI.A.9 | 1A |
| 6.20 | VI.G.20 | 3A |
| 6.21 | VI.G.15 | 1B |
| 6.22 | VI.D.9 | 3A |
| 6.24 | VI.A.4 | 1B |
| 6.25 | V.F.3 | 2A |
| 6.26 | V.F.2 | 2A |
| 6.27 | VI.B.7 | 2A |
| 6.28 | VI.A.10 | 3E |
| 6.31 | VI.K.12 | 3A |

| NRC HED NO. | SEABROOK HED NO. | PRIORITY SCHEDULE |
|---|---|---|
| 6.32 | VI.E.10 | 3A |
| 6.33 | VI.E.8 | 3B |
| 6.35 | V.I.1 | 3B |
| 6.36 | VI.H.3 | 2B |
| 6.37 | VI.H.1 | 2A |
| 6.38 | VI.F.5 | 3B |
| 6.39 | VI.F.4 | 1B |
| 6.40 | VI.F.1 | 1B |
| 6.41 | VI.E.23 | 3B |
| 6.42 | VI.E.5 | 1B |
| 6.43 | VI.C.2 | 1B |
| 6.44 | VI.K.10 | 3A |
| 6.45 | VI.H.8 | 2A |
| 6.46 | VI.H.4 | 3B |
| 6.47 | VI.F.2 | 2B |
| 6.48 | VI.D.1 | 2B |
| 6.49 | VI.G.1 | 3A |
| 6.52 | V.H.1 | 2B |
| 6.53 | V.H.4 | 2B |
| 6.54 | VI.D.2 | 2A |
| **B7.0 PROCESS COMPUTERS** | | |
| 7.1 | V.A.4 | 3E |
| **B8.0 PANEL LAYOUT** | | |
| 8.1 | VI.C.3 | NA |
| 8.2 | VI.A.14 | 1B |
| 8.3 | VI.A.15 | 1B |
| 8.4 | VI.A.16 | 2A |
| 8.5 | VI.A.17 | 1A |

B8.0 PANEL LAYOUT (Cont'd)

| NRC HED NO. | SEABROOK HED NO. | PRIORITY SCHEDULE |
|---|---|---|
| 8.6 | VI.B.1 | 2A |
| 8.7 | VI.B.5 | 3E |
| 8.8 | VI.E.11 | 3A |
| 8.10 | VI.G.11 | 3E |
| 8.11 | VI.E.17 | 3B |
| 8.12 | VI.C.12 | 1A |
| 8.15 | VI.C.20 | 3E |
| 8.16 | VI.B.3 | 2A |
| 8.17 | VI.A.5 | 2A |
| 8.19 | VI.C.23 | 2A |
| 8.20 | VI.D.5 | 2B |
| 8.21 | VI.D 11 | 1A |
| 8.23 | VI.K.5 | 3B |
| 8.25 | VI.D.10 | 1A |
| 8.26 | VI.D.3 | 2B |
| 8.27 | VI.C.7 | 1A |
| 8.28 | VI.C.4 | 1A |
| 8.29 | VI.B.4 | 3A |

| NRC HED NO. | SEABROOK HED NO. | PRIORITY SCHEDULE |
|---|---|---|
| 8.30 | VI.A.8 | 1A |
| 8.31 | VI.D.20 | 3B |
| 8.32 | VI.E.3 | 3A |
| 8.34 | VI.F.8 | 2B |
| 8.35 | VI.F.3 | 3E |
| 8.36 | VI.E.2 | 3A |
| 8.37 | VI.E.9 | 3A |
| 8.38 | VI.E.24 | 3A |
| 8.39 | VI.E.25 | 3B |
| 8.47 | VI.D.4 | 1A |

B9.0 CONTROL-DISPLAY INTEGRATION

| NRC HED NO. | SEABROOK HED NO. | PRIORITY SCHEDULE |
|---|---|---|
| 9.1 | VI.D.21 | 2A |
| 9.2 | VI.H.5 | 2A |
| 9.3 | VI.A.3 | 1B |
| 9.5 | VI.E.1 | 3E |
| 9.6 | VI.C.22 | 3E |

APPENDIX

PART C

HUMAN FACTORS ENGINEERING IN-PROGRESS AUDIT

OF THE DETAILED CONTROL ROOM DESIGN REVIEW

FOR

PUBLIC SERVICE OF NEW HAMPSHIRE

SEABROOK STATION

Part C - This part contains the applicant items for which the stated resolution is not completely defined. A revised resolution should be submitted at least 120 days PTLF, and the schedule for implementation of the resolution should be committed for completion PTLF.

Licensee Response

For many of the following items, it is unclear what problem the NRC has with the existing resolution. For those, we assume that it is a priority or schedule problem, and have updated those items.

C2.0 COMMUNICATIONS

FINDING

2.1 There is no unique audible signal for first out indication. (V.D.6)

Resolution: A unique audible signal will be developed for first out. Priority 1B.

Licensee Response: A unique audible signal for first out indication will be developed. Priority 1A.

C3.0 ANNUNCIATOR WARNING SYSTEMS

FINDING

3.3 There is insufficient alarm or feedback regarding containment radiation for operator at Panel A or B. There is a danger of the alarm being cancelled and missing a high radiation signal. (VI.A.19)

Resolution: The Radiation Monitoring System, including alarms, will be addressed in a future supplement to this report. Priority 2B.

Licensee Response: This system will be reviewed and resolution of any HEDs submitted to NRC at least 120 days PTLF. Priority 2A.

3.4 The first out priority does not address Safety Injection. There is no indication of the cause of an SI actuation. A first out indication should be developed. (V.D.5)

Resolution: First out indication for SI actuation will be developed. Priority 1B.

Licensee Response: First out indication for SI actuation will be developed. Priority 1A.

3.8 There is no easily visible tile location matrix. (V.D.3)

Resolution: Develop an easily visible tile location matrix. Priority 3B.

Licensee Response: An easily visible tile location matrix has been developed. Priority 3A.

C4.0 CONTROLS

FINDING

4.4 Trip/reset function is inconsistent. (V.L.1)

Resolution: (a) We will investigate the use of pushbuttons. (4.3 REF) (b) Make switches consistent with respect to direction of trip and reset. (4.2.1 REF) (c) Investigate the use of switch handles that are different from other board switches. Priority 1B. (4.2.2 REF)

Licensee Response: The results of our investigation are: (1) the trip/reset switches will be made consistent with respect to the direction of throw; reset switches will be made consistent with respect to the direction of throw; and (2) trip switches will be provided with unique handles. Priority 1A.

4.8 The switches for emergency trip are not protected from inadvertent operation. (VI.J.4)

Resolution: The new MSIV panel will be checked to see if this is still a problem. Priority 2D.

NRC Position: It was stated that this panel will be removed, which appears to contradict Finding 8.9. This apparent contradiction should be resolved and reported 120 days PTLF.

Licensee Response: The panel will be removed and replaced with a differently designed MSIV panel. When it is replaced, it will be reviewed to ascertain if the HED remains. Priority 2C.

4.9 Some turbine controllers and pushbuttons 3" from edge. (VI.E.18)

Resolution: These are startup control switches, not used at power. However, there is some potential for affecting the T-G if they were inadvertently operated. Provision of a guard of some sort will be investigated. Priority 3D.

Licensee Response: Guards will be provided. Priority 3A.

4.17 Should in-out direction of control rod drive joystick be reversed? This should be resolved by a poll of the operators; there is no "right answer". (VI.C.18)

Resolution: Poll shows operators divided 50/50 on this question. The joystick will be made push-IN, pull-OUT. Priority 2A.

NRC Position: The direction of movement of rod control drive joysticks is not consistent throughout the nuclear power industry. Joystick motion should be consistent with the rod control and position indications. These are push-OUT-up and pull-IN-down. Joystick motion should remain as is and not be changed as described in the Resolution.

Licensee Response: The joystick operation will be left as originally designed, push-OUT-up, pull-IN-down.

C5.0 VISUAL DISPLAYS

FINDING

5.1 No flow indicator exists for startup feed pump. (VI.D.8)

Resolution: The need for this is under study. Priority 2D.

NRC Position: The study should be made and results reported. Detailed function and task analysis should provide this information. If needed, the indicator should be installed within 120 days after start-up.

Licensee Response: Further study has shown that there is no need for such indication. This will be deleted as an HED.

5.4 Status Lights: In general, all status light panels are confusing in arrangement and wording. (V.B)

Resolution: Arrangements and wording are being checked and changes made as necessary. Demarcation is being added. Priority 1B.

Licensee Response: Arrangements and wording have been checked, and changes made as necessary. Demarcation has been added. Priority 1A.

5.5 Need Tave PAM recorder or Tc and Th on the same recorder to verify Tave decreasing to 557 degrees as required in EO procedure. Need degrees Fahrenheit scale on this recorder. (VI.C.8)

Resolution: Make Tave recorder into PAM recorder. Priority 2B.

NRC Position: Staff feels this HED and its resolution should be studied further. Detailed function and task analysis should provide the information.

Licensee Response: Further study shows that the indication needed in this procedure step is that Reactor Coolant Temperature is decreasing, not that Tave is decreasing. The operator can verify decreasing coolant temperature using other instrumentation located on the MCB, such as Tc, Th, Delta T, and Incore Temperature. Therefore, A Tave recorder is not necessary. Priority 3E.

5.7 There is a need for current and historical indication of % delta flux as a function of power and setpoints displayed continuously. (VI.C.11)

Resolution: This information can be supplied in several ways, either in the computer or by recorder. This will be studied to see which is more appropriate. Priority 3B.

NRC Position: The operators feel that the Ion Chamber recorders on Panel DF-2 are not needed, and suggested that the % delta-flux recorder described in HED VI-C-11 should be put in this space.

Licensee Response: Further study has been done. This information will be put in the computer and can then be displayed on the trend recorders as necessary. Priority 3A.

5.8 There is a need for DP meter plus/minus 0 - 300 psi to go with PI507 and 508. Need better way to watch SG feed and main steam delta P. Requirement is to hold the programmed delta P across feed regulator valves. This is especially needed if auto system fails. (VI.D.13)

Resolution: One indicator will be added. Priority 2B.

Licensee Response: Further study shows that the Feedwater Control Valve Controllers presently have a Delta P indicator with a 0-100% scale. This scale will be changed to Delta P in psig, resolving the problem. Priority 2A.

5.9 There is no low-range MFW flow indication for SGs for startup conditions. (VI.D.19)

Resolution: The need for this will be assessed during startup. If the automatic level control on the bypass does not work as designed, then an indicator will be considered. Priority 2C.

NRC Position: A detailed function and task analysis of the start-up process should determine the need for this information. Determination should be made PTLF.

Licensee Response: Our analysis shows that the system is designed to function without this information; therefore the information need not be added.

However, the knowledge and past experience of the people taking part in this review indicates there is some chance that the information could be needed if the system control does not function as well as it is designed to. If this is true, then the indicator will be needed.

Until the operators have gained some experience with the system, there is no way to know if the indicator is needed.

Therefore, determination can not and will not be made PTLF. The determination will be made during the first operating cycle, under actual operating conditions; and the indicator will be added prior to start-up after the first refueling interval if it is necessary. Priority 2C.

It should be noted that the NRC staff has developed the position on many potential HEDs that a "detailed function and task analysis of the process should determine the need for information" before plant operation. It is our position that, while this is true for the vast majority of potential HEDs, there is some small number where it is not true, where actual operating experience is needed. These will not be verified (and fixed) until there has been some plant operating experience. It should also be noted that none of these are a Priority 1 item, requiring immediate correction.

16C

5.12 There is no turbine generator emergency bearing oil pump header pressure indication available in the Control Room. (VI.E.20)

Resolution: This pressure and others are available locally. The need for indication in the Control Room will be assessed during the first operating cycle. If changes are needed, they will be made. Priority 3C.

Licensee Response: There is no indication of what the NRC staff's problem is with respect to this item. We will assume that it is the same as on the previous finding, (5.9) and our response is the same.

This is another item where the system is designed to function correctly without this indication; and task analysis shows this. However, past experience and knowledge indicate that it might not. As noted, this will be assessed during the first operating cycle, and changes made as necessary. Priority 3C.

5.14 Emergency DGs do not have transfer voltmeters. There have been instances where operator did not know if the regulator was following incoming voltage or not. (VI.G.19)

Resolution: Indication is available. Better labeling will be added, and the operator will be trained on the operation of the system. Priority 3A.

NRC Position: It is understood that this resolution may be modified. NRC feels that this HED is not clear and needs further study.

Licensee Response: Further study indicates the need for a null voltmeter, not a transfer voltmeter. A null voltmeter for each Emergency DG voltage regulator has been added to the panel. Priority 2A.

5.15 No accumulator levels are available from back panel. (VI.H.10)

Resolution: These are not needed. Indicators are available on the front panel. At present, it appears the required evolution can be accomplished using the front panel indicators.

NRC Position: No priority was stated for this HED. A detailed function and task analysis should determine accumulator level need and location.

Licensee Response: The priority for this is 3E. There is no need for further task analyses as the present task analysis has determined that the required evaluation can be done using the available indicators.

The evaluation is not one required during any safe shutdown procedure. It is only for the filling of the accumulators.

The resolution is:

> These are not needed. Indicators are available on the front panel. The required evaluation can be accomplished using the front panel indicators. Priority 3E.

5.23 The narrow-range scales on seal return recorders should read 0-1 gpm linear to allow proper startup condition at 0.2 gpm. It would be better if both narrow and wide were on the same recorders. Scale range 0-6 is ok on wide range so long as it is linear. (VI.B.6)

Resolution: Change the recorders as indicated above. Priority 2B.

NRC Position: The HED statement is not clear. Needs better explanation of problem.

Licensee Response: The problem on the seal return recorders has been further evaluated. The required function is that the operator determine that there is a minimum of 0.2 gpm flow prior to starting the reactor coolant pumps. This is a planned evolution that is performed in starting up the plant. The resolution of the problem is to change the recorder scale to 0-1 gpm to ensure that the operator can determine that a minimum of 0.2 gpm exists. The scale will remain square root to highlight the measurement inaccuracies at the lower end of this range. The wide-range scale is on another pen on the same recorder, and will remain as is. The Simulator will be changed to conform to the MCB. Priority 3C.

5.24 The RCP ammeters have too insensitive a scale to distinguish limits on current. They need narrow range. (VI.B.8)

Resolution: Procedures should be reviewed to insure this is necessary. Band the normal range after this is determined during plant startup. If it is determined after startup that a narrow-range indicator is necessary, it will be added. Priority 3C.

NRC Position: A detailed function and task analysis should describe the characteristics of the information required. It should be determined PTLF.

Licensee Response: The required function is to provide an approximate indication that the RCP motors are drawing full load current. The actual current drawn by the motor will vary with bus voltage fluctuations, the number of RCPs running, the temperature of the primary coolant, and the as-built characteristics of the motor. The present indicators have a range of 0-400 amps; they are sufficiently accurate for the required function. The normal range will be determined during startup and banded on these indicators (reference HED V.G.3). Priority 3E.

5.29 Status lights - lettering is small and the lights are high. (V.A.3)

Resolution: This is a deviation from human factors criteria. An effort has been made to limit the number of words to those necessary and effective. The tiles have been grouped to establish a pattern which will serve the operator as a recognition tool. An identification has been added to the tile layout. If a particular light is out, the operator will approach the board to read it. If he cannot read it directly, he will use the identification matrix to locate it on a hand-held hard copy located at the board. A method will be devised to keep these hard copies available at the board. Priority 3B.

NRC Position: This is a cumbersome solution to a human factors design discrepancy. It is acceptable only if the task analysis can justify that the method of operation (e.g., pattern recognition, use of identification matrix) allow the tasks to be performed with sufficient speed and accuracy.

Licensee Response: This is not a "cumbersome solution" to an HED. Pattern recognition is an acceptable method of operation, and the tiles have been specifically regrouped to facilitate this.

The operator will be able to distinguish a light that did not go on. The identification matrix can easily be read from the operator's work station. A hard copy of the matrix will be available in the Control Room for the operator's use. Priority 2A.

5.33 Recorder scales have not been reviewed yet because they were not available. However, some examples seem to deviate from accepted method. (V.J.4)

Resolution: After installation, all recorder scales will be reviewed for correct correlation with respective indicators. Priority 2B.

Licensee Response: We confirm that all recorder scales will be reviewed for correlation with respective indicators and a schedule submitted for any necessary corrections 120 days PTLF. Priority 2A.

5.27 Tank level indicators should have "gallons" on scales, as Technical Specifications and procedures call for action based upon gallons. (V.C.)

Resolution: Tank level should be in units consistent with Technical Specifications and procedures. If % is chosen, then engineering units should also be marked on the indicator scale. Priority 2B.

NRC Position: Units should be consistent with Tech Specs.

Licensee Response: The units will be consistent with Tech Specs. However, for operator convenience, if % is the Tech Spec unit, then engineering units will also be marked on the indicator scale. Priority 2A.

5.34 Normal and abnormal ranges are not indicated. (V.J.3)

<u>Resolution</u>: Operating plant management will determine what, if any, markings are necessary. These will be shown on the indicators. Priority 2C.

<u>NRC Position</u>: The detailed function and task analysis should determine the characteristics of the information required.

<u>Licensee Response</u>: As previously stated, analysis can give and has given an approximation of what the correct ranges should be. However, the exact range cannot be determined until a system is functioning in normal use.

These ranges will be determined, and correction made prior to start-up after the first refueling. Priority 2C.

## <u>C6.0 LABELS AND LOCATION AIDS</u>

### <u>FINDING</u>

6.4 Demarcation and labeling need to be addressed. (VI.I.7)

<u>Resolution</u>: These will be addressed during generic demarcation and labeling effort. Priority 2B.

<u>Licensee Response</u>: Panel CR demarcation and labeling have been addressed. Priority 2A.

6.11 On the Tracor NR-45 it is impossible to tell which pen is selected by which switch. It is better labeled on the MCB. With the door closed, the scale is obscured by door frame; glass on scale has poor transparency. (VI.C.13)

<u>Resolution</u>: The labeling on the simulator will be upgraded. The door will be either rebuilt or removed. Priority 2B.

<u>Licensee Response</u>: The door on the Simulator and MCB recorders will be rebuilt. The labeling on the Simulator will be upgraded. Priority 2A.

6.12 On thermal regeneration system three white lights on selector switch are not labeled, therefore are not clear. (VI.C.6)

<u>Resolution</u>: The lights will be labeled. Priority 1B. Additionally, this needs further study to see if other controls are needed. Priority 3C.

<u>NRC Position</u>: The comment concerning further study to see if other controls are needed is not clear. The detailed function and task analysis should determine the need for control capability.

<u>Licensee Response</u>: Further analysis has shown that no other controls are needed. Priority 3E.

6.23 The labels on containment spray isolation now indicates 1/2 which is ambiguous. They should indicate that both switches must be actuated. (VI.A.6)

<u>Resolution</u>: Clarify the label and the procedure. Generic Item I.F.3. Priority 1B.

<u>Licensee Response</u>: The label has been clarified to indicate that both switches must be activated. Priority 1A.

6.29 Abbreviations must be made more consistent between board labels, status lights, annunciators and procedures to the extent possible in the Control Room. (V.E.1)

<u>Resolution</u>: The operating staff will develop a list of consistent abbreviations to be used throughout the Control Room where possible. Priority 3B.

Licensee Response: A list of consistent abbreviations to be used throughout the Control Room has been developed. As changes are made on labels, status lights, etc., these abbreviations are being used. Priority 3A.

6.34 Demarcation and Labeling

1. An identification of functional groups should be developed for all panels as necessary, using demarcation lines and hierarchical labeling.

(V.C.1)

Resolution: This will be done. Priority 1B.

NRC Position: Also see Finding 6.56 (Part D) regarding the need for a consistent hierarchical labeling scheme.

Licensee Response: A consistent hierarchical labeling scheme, using demarcation lines, has been developed and is in use. Priority 1A.

6.50 Color contrast is not good in some areas. Examples are use of black arrows on brown mimic, and use of the same color for different flow paths in a mimic. (V.H.2)

Resolution: We will investigate the problem and develop better contrasts by using both color and width variations. Priority 2B.

NRC Position: The staff has requested a description of all colors used in all contexts in the control room.

Licensee Response: A description of all colors in use in the control room, together with their context, will be submitted by 120 day PTLF. Priority 2A.

6.51 Paint is chipping off the brass mimic on many of the panels. There is some concern over the durability of the painted brass. (V.H.3)

Resolution: Either another material will be used or the brass will be periodically repainted as needed. Priority 2B.

Licensee Response: Plastic is now being used for mimic material. Priority 2A.

## C8.0 PANEL LAYOUT

FINDING

8.9 The new MSIV test panel needs to be checked when installed. (VI.J.2)

Resolution: This will be checked when it is installed. Priority 2D.

NRC Position: The results of checking this panel should be reported, a resolution for any problems found selected, and a commitment made to complete corrections PTLF. Also see Finding 4.8.

Licensee Response: This panel will be removed and replaced with a differently designed MSIV panel. When it is replaced, it will be reviewed to ascertain if there are HEDs. The HEDs will be corrected prior to startup after the first refueling. Priority 2C.

8.11 The generator breaker control switch interferes with the indicating light below it. (VI.E.17)

Resolution: This is a hardware problem. A longer stem could be used, extending the switch further out from the board. Priority 3B.

NRC Position: It is not clear what will be done to resolve the HED.

Licensee Response: The indicating lights have been modified so that they no longer present an interference problem. Priority 3A.

8.13 The CVCS component arrangement and mimic are confusing. (VI.C.1)

Resolution: This section has been reviewed and will be rearranged to eliminate the confusion. Priority 1A.

Licensee Response: The CVCS component arrangement and mimic has been rearranged to eliminate confusion. Priority 1A.

8.14 The arrangement and mimic from CS7320 to large arrow could be cleaner. The locations for RCP oil lift pump switches and RMW to RCPs should be swapped for cleaner arrangement. (VI.B.2)

Resolution: Arrangement and mimic have been reviewed. A less confusion arrangement has been worked out and will be implemented. Priority 3B.

Licensee Response: This arrangement has been cleaned up and changes implemented. Priority 3A.

8.22 SG PAM recorders should be ABCD, with level and pressure on each, or else get levels and pressures together with Generic labels. (VI.D.12)

Resolution: The resolution of this item requires a detailed study of train assignments and power sources. This will take some time to do. Priority 2B.

Licensee Response: Each recorder will indicate level and pressure from a single steam generator. They will be arranged A-B-C-D on the board. Priority 2A.

8.24 The new fire panel needs review. (VI.K.4)

Resolution: The panel will be reviewed when it is available. Priority 2D.

NRC Position: This panel is now available. Review should be made, a resolution selected and corrections committed to be completed PTLF.

Licensee Response: The panel is now available, but point assignments have not yet been made. It will be reviewed PTLF. Priority 2A.

8.46 The arrangement of switches and mimic of the safeguards panel on both A and B are confusing, with a lot of mirror imaging used. (VI.A.1)

Resolution: Develop a layout that addresses the confusion problem. Priority 1A.

NRC Position: New layout should also remove the mirror imaging.

Licensee Resolution: A layout has been developed and implemented. It eliminates the majority of the mirror imagery, but not all. The new layout has been reviewed and approved by the Human Factors Consultant and the plant operators. Priority 1A.

C9.0 CONTROL-DISPLAY INTEGRATION

FINDING

9.4 The operator needs more positive indication of hotwell conditions. Hotwell makeup and reject valve indications are not available. (VI.E.19)

Resolution: Add valve indicator. Priority 3C.

NRC Position: It is understood that the method of control is not yet determined, and that operating experience is needed before a resolution is selected. In this special case the proposed resolution should be submitted 120 days prior to shut down for first refueling outage, and implementation of the resolution committed for completion prior to start up after the first refueling outage.

Licensee Response: The method of control has been decided. Hotwell and spill valve indication has been provided. Priority 2A.

APPENDIX

PART D

HUMAN FACTORS ENGINEERING

CONTROL ROOM IN-PROGRESS AUDIT

FOR

SEABROOK STATION

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

Part D - This Part contains (1) the applicant items for which the proposed resolution is unsatisfactory, and (2) Human Engineering Discrepancies (HEDs) identified by the NRC review team during the in-progress audit. These items and HEDs must be reviewed by the applicant and a resolution and implementation schedule submitted 120 days PTLF. Discrepancies must be corrected PTLF, or on a schedule approved by the NRC.

D1.0 CONTROL ROOM WORKSPACE

FINDING

1.6 On panel IR the Main Turbine RPM recorder is too low on the panel (e.g., 27" from the floor).

Licensee Response: The information is provided on the computer. Priority 3E.

D3.0 ANNUNCIATOR WARNING SYSTEMS

FINDING

3.12 There are no first-out alarms of turbine generator events.

Licensee Response: This is not an HED. The EHC System presently provides this indication for the turbine and generator.

D5.0 VISUAL DISPLAYS

FINDING

5.10 Turbine megawatt has poor scale. (VI.E.12)

Resolution: This is a vendor-supplied meter. There are other megawatt indications that the operator can refer to. Leave as is Priority 3E.

NRC Position: If indication is not needed, it should be removed, if it is needed, it should be corrected.

Licensee Response: The scale will be changed to provide readable indication. Priority 3C.

5.11 The turbine speed indicator should have 1800 marked on scale. (VI.E.15)

Resolution: This will be marked on scale. Priority 3A.

NRC Position: Problem is more complex than just the addition described. Function and task analysis should determine precisely what is needed.

Licensee Response: The critical speeds will be determined from the start-up procedure. These critical speeds and 1800 rpm will be marked on the scale. Priority 3C.

5.26 PZR level is a narrow-range recorder with a 0-100% scale. (VI.B.11)

Resolution: This is not a wide-range scale. The operators will be trained to recognize this. Priority 3E.

NRC Position: If it is a narrow-range scale, 0-100% is not appropriate.

Licensee Response: The above resolution is incorrect. It is not a case of wide range or narrow range. It is hot/cold calibration. This is a hot calibration scale, and should be 0-100%. The recorder is labeled to indicate this. Priority 3E.

5.61 Panel DF has 2 controls but no indication of the status of Flow and Chiller Temperature. The meters needed by the operators are on Back Panel BR-1, and require a trip away from the front panel to see the meters.

Licensee Response: (See NRC Item 6.12, Seabrook Item VI.C.6) Indicators are available behind the board. Indication will be added to the computer for the operator. Priority 3C.

5.62 Dual range scale meters sometimes use different scale units (e.g., 300 psi, $3 \times 10^2$ psi).

Licensee Response: Some dual indicators have a different notation on the same indicator. This will be changed so that the notation is the same on a single dual-scale indicator if the variable is the same. It will not be changed if the variables are different. Priority 3C.

5.63 The four steam generator water level recorders on Panel FF are single speed. A multispeed recorder is needed so that the operator can see start-up mode level oscillations.

Licensee Response: Four recorders will be provided. Priority 2A.

5.64 On the EF-2 steam generator feedwater level recorder, the position of the pen is hard to see from the front of the recorder, and the time lag of the trace makes it difficult for the operator to follow the start-up trend.

Licensee Response: The trending capability is available in the computer. Priority 3E.

6.15 There is an odd-sized nameplate on cooling tower switchgear. (VI.I.2)

Resolution: There is no room for a larger size. It is legible as is. Priority 3E.

NRC Position: This is class 1E safety equipment and the staff considers the priority too low. The staff believes all nameplates should be of consistent size.

Licensee Response: The largest space available has been allotted to this. The lettering is the same size as other indicators. The benefit of changing one label to a larger size does not justify the cost of a major revision of this panel. Priority 3E.

6.30 "Core monitor" should be relabeled to be other than "core". (VI.K.8)

Resolution: This is familiar to operator, leave as is. Priority 3E.

NRC Position: The label should read "GENERATOR CORE".

Licensee Response: We will change the label to read "Generator Core". Priority ~~3D~~. 3A

6.55 On panel IR the main turbine RPM recorder does not have a label.

Licensee Response: We will add a label. Priority ~~3D~~. 3A

6.56 The control room uses no consistent hierarchical panel labeling scheme. (Also see finding 6.34).

Licensee Response: A hierarchical panel labeling scheme has been developed and is in use. Priority 1A.

8.18 On Panel B, the present layout of the accumulators (A-C-B-D left to right) is confusing. (VI.A.2)

Resolution: The recommendation of the Human Factors Review Group is to change the layout to A-B-C-D left to right. This eliminates the problem. Priority 3A.

However, the decision has been made not to make the change. The justification is that significant layout changes to MCB Section BF has been made to address the confusing arrangement and mimic on Sections AF and BF (HED, Page 25, A.1). The ACBD accumulator layout is acceptable for the following reasons:

1. The priority is 3A. The Human Factors Review Group agrees there is little or no potential for uncorrected operator error and risk of consequences.

2. Accumulators are passive devices. There is no chance for uncorrected operator error in the event of an accident as all actions required for injection are taken during startup.

3. The A-C (Train A) B-D (Train B) layout emphasizes the train assignment of the isolation valves.

If accumulators are moved, major separation barrier rework and additional switch and indicator movements will be necessary.

NRC Position: The recommended change to ABCD was considered important by several operators. The staff needs additional justification through task analysis results for not making the change.

Licensee Response: In addition to the justification given in our initial resolution, we have further evaluated the tasks associated with the layout of the accumulator instrumentation and controls on the front of the main control board and have determined that this HED does not represent a significant risk and will not be corrected.

The following tasks were identified:

Normal Operations:

1. Maintaining Technical Specification conditions by filling, draining, pressurizing, or venting.

2. Isolating or unisolating when changing plant modes.

Emergency Operations:

1. Verifying discharge of all 4 accumulators.

2. Isolating or venting during cooldown after accident that did not result in depressurization and accumulator discharge.

The normal operations associated with maintaining accumulator parameters require that the proper condition be observed after the corrective action. Any evolution that was performed on the wrong accumulator will be detected and corrected immediately. These evolutions are not performed during or immediately after an accident and there is a very low probability of an accident occurring while an accumulator is being drained/filled or pressurized/vented.

Verifying accumulator discharge is done simultaneously. The actual accumulator being observed is not significant.

Isolating and unisolating accumulators are done simultaneously. The identification of the particular accumulator is not significant unless an isolation valve problem is encountered. If the valve does not operate during a normal heatup or cooldown, there is sufficient time for the manual operation of the valve to be performed and to verify correct valve lineup. During accident conditions, the failure of an isolation valve to close is compensated for by opening the vent valves on the same accumulator. Mimic and demarcation are provided to ensure that the proper vent valves are identified.

8.33 Containment isolation valve positions are inconsistent, re: train correspondence to physical inside-outside of containment. (VI.H.2)

<u>Resolution</u>: The operator looks to insure that all are closed (green). If one does not shut, then he shuts it. It does not matter if it is inside or outside, the operator response is the same. Therefore, this can be left as is. Priority 3E.

NRC Position: It is understood that the stated resolution is being changed. The revised resolution needs to be reviewed by the staff.

Licensee Response: The resolution has not changed.

8.48 The Steam Generator Blow Down System controls left-to-right sequence is interrupted by a different system control as follows 1 - x - 2 - 3. (Also see Finding 9.2., Part B.)

Licensee Response: This has been resolved by mimicking and demarcation. Priority 2A.

## D9.0 CONTROL-DISPLAY INTEGRATION

### FINDING

9.7 Operators feel that the Steam Dump meter on FF-1 should be repeated on DF-2 to make a more stable interface between the primary and secondary system. The operators must walk 15 feet from the controls to see the meter.

Licensee Response: These have been demarcated and labeled to resolve the problem. This will be reviewed during plant operation. If the problem still exists, further changes will be made. Priority 3C.

9.8 On Panel D, operators stated that Start Switch (CS-P-128), Speed Control (RCSK-459-A) and Charging Flow Indicator (F-1-121-A) are too far apart for convenient operation.

Licensee Response: These have been demarcated and labeled to resolve the problem. This will be reviewed during plant operation. If the problem still exists, further changes will be made. Priority 3C.

PART (3)

NEW HEDs

Human Engineering Deficiencies Found During:

- Hard-Wired Annunciator Review
- VAS Review
- Remote Shutdown Panel Review
- CR Architecture Review

(185)

L. HARD-WIRED ALARMS

1. Grouping of Tiles within Boxes:

On Panel B, the tiles for the two trains do not correspond. There are two Train B tiles on the A train box which should be moved to the B train box.

The SCCW alarms on the Panel H box ought to be on the Panel F box.

On Panel H the left-hand box is 4 x 6, the right one is 6 x 6. At least the left-most 4 x 6 portion of the right-hand box should correspond to the left-hand 4 x 6 box.

On all annunciator boxes, some alarms come up on panels that are separated from the controls and displays associated with the alarm. Additionally, the wording on some tiles does not indicate the correct parameter alarmed.

Resolution:

A general review will be undertaken to determine correct grouping and correct wording on the tiles. Priority 2A.

Necessary changes will be made Priority 2C.

2. Readability of Tiles:

Tiles can be read easily when standing directly in front of the corresponding box. However when standing at the silence-acknowledge stations at Panels B and H, there is some difficulty in reading some of the tiles acknowledged from those stations - partly because of angle of view, partly because of distance.

Resolution:

The hardwired annunciators are a backup to the CRTs. The letters have been increased in size to 1/4 inch. The letter size on the tiles will be re-evaluated. If it can be increased to 5/16 inch and still present clear messages, then the letter size will be changed. If the increase in size causes crowding, the change will not be made. Priority 3C.

3. Alphanumeric Tile Locater:

Tile locater code should be painted or otherwise indicated with capital A or B for train, letters along the left edge to indicate row, numbers along top edge to indicate column. Tiny locater codes on tiles themselves can stay, since they can be useful to prevent putting tile back in the wrong location.

Resolution:

This code and matrix has been developed and will be installed. Priority 3A.

4. The flash rates specified in the annunciator specification do not agree with the flash rates observed on the annunciator in the simulator. The following are the desired flash rates based upon simulator observations:

Incoming Alarms - Fast Flash, 2 per sec.;
Clearing Alarms - Slow Flash, 1 per sec.; and
Both with equal on-off times.

Resolution:

The annunciator in the MCB will be checked to see that it conforms to those guidelines. If it does not, the flash rates will be changed to meet the guidelines. Priority 3A.

## M. <u>VIDEO ALARM SYSTEM</u>

1. The indication that "resetting" messages are present would be more appropriately placed on the left side of the CRTs.

   <u>Resolution</u>:

   This indication will be moved to the left side of the CRT. Priority 3A.

2. The colors on different CRTs are not always the same. For example, orange on one CRT is not the same as orange on another CRT.

   <u>Resolution</u>:

   This is acceptable provided orange and yellow are made discriminable from each other on the same CRT. This will ensure that priority one alarms are discriminable from priority three alarms.

   Adjustment of CRT guns to insure discrimination will be covered under maintenance procedures. Priority 3A.

## N. COMMON ALARM SYSTEM

1. The First-Out reset push button is not installed.

   Resolution:

   This will be installed. Priority 1A.

2. The silence, acknowledge, and reset push buttons are duplicated on the keyboard and are insufficiently discriminable. Each set is dedicated to either the VAS or the backup annunciator requiring additional operator actions to acknowledge alarms that come in on both systems. In addition, two keystrokes are required to acknowledge VAS alarms from the keyboard.

   Resolution:

   The existing push-button stations with silence, acknowledge, and reset will be wired to interface with both systems. The acknowledge and reset functions currently on the keyboard will be disabled. For operator convenience, the acknowledge push button will also silence the horn.

   The silence push button will be made distinctive from the other two push buttons. Silence, acknowledge, and reset push buttons shall be distinguishable from each other by color as well as location relative to the others. The silence push button shall be gray, the acknowledge magenta, and the reset white. Priority 3C.

3. For audible signals, there is presently insufficient discriminability between alarm onset and reset, and between primary and secondary alarms.

Resolution:

These signals have been reviewed. The consensus of the review team is that the following signals, in their specific Betatone terminology, be used:

"yelp" at two Hertz for first-out alarm.

"warble" at one Hertz for primary alarm.

"beep" at one Hertz for secondary alarm, where single frequency tone is set midway between the two frequencies comprising the "warble".

"gong" for both resets, with higher frequency tone than "beep" or "warble" and slightly lower intensity. Both the primary and secondary reset horns will be set to give identical sounds.

"wow" for fire, set loud at about one Hertz and different in frequency from "yelp".

Priority 2A.

4. The test station for the hard-wired annunciator boxes on Panel H is too far from the acknowledge station for efficient operation.

Resolution:

The test push button will be moved to a position nearer the acknowledge station. Priority 3C.

5. To make the acknowledge stations more efficient, the acknowledge button should also silence the alarm.

Resolution:

This will be done. Priority 2A.

6. For the first-out annunciator, the test sequence causes all tiles to flash red.

<u>Resolution</u>:

The red bulbs will be removed from all hard-wired annunciators except the first-out designated windows in UA-52. The white bulbs will be tested later in the sequence. Priority 3A.

7. Alarm and reset messages cannot be readily discriminated on the alarm printer.

<u>Resolution</u>:

Reset messages will be identified by indenting the message from the left-hand margin. Priority 3A.

8. Printers have no generic labels, such as Alarm, Alert, Status, etc.

<u>Resolution</u>:

These labels will be added. Priority 3A.

O. <u>REMOTE SAFE SHUTDOWN PANELS CP-108 A, B</u>

1. Demarcation and generic labeling is needed.

   <u>Resolution</u>:

   This will be added. Priority 2A.

2. Displays are slightly above the recommended height.

   <u>Resolution</u>:

   Displays are large, and can be easily seen. No corrective action is necessary. Priority 3E.

3. The atmospheric dump controllers are 12 inches higher than the maximum recommended height.

   <u>Resolution</u>:

   A 12-inch high moveable bench will be provided to allow the operators to easily reach the controllers. Priority 2A.

4. The main steam isolation valve select switch is in the mid-row of switches. It is associated with indicating lights on the top row. This association should be made more apparent.

   <u>Resolution</u>:

   The association will be clearly demarcated. Priority 2A.

5. The MSIV trip switch should be labeled more clearly.

   <u>Resolution</u>:

   The nameplate will be labeled MSIV TRIP SWITCH. The escutcheon plate will be labeled REMOTE-LOCAL/TRIP. Priority 3A.

6. There is a mixture of OT2 and SBM switches used for valves, pumps, and fans. There is no consistent use of one type of switch for one specific purpose.

Resolution:

With one exception, pumps use SBM switches. Except for those cases where a valve requires an SBM switch because of required switch action or contacts (SG dump valves), valves use OT-2 switches. The one pump exception is clearly labeled, and its module is demarcated. The need for tactile differentiation does not exist. No change is necessary. Priority 3E.

7. SG dump valves switches should be painted purple.

Resolution:

These will be painted. Priority 2A.

8. There is no indication on the switchgear and MCCs to show which are associated with the Remote Safe Shutdown Panel. Additionally, the actual component label is too small.

Resolution:

Add a purple nameplate with component identification and the RSS identification on the RSS-associated switchgear and MCC breaker cabinets. Add a purple dot on the specific breakers in the switchgear or MCCs. Priority 1A.

9. Selector switches on CP-108A, B, Switchgear and MCCs are inconsistent with respect to remote-local position.

Resolution:

All switches will be changed to left-remote, right-local. Priority 1A.

10. There should be some indication of safety train on each Remote Safe Shutdown Panel.

<u>Resolution</u>:

The major panel identification nameplate will be made larger and will be colored red or white to identify the safety train. Priority 2A. The nameplates will read Train A (B) Safe Shutdown Panel, CP-108A (B).

11. Controller labels should be consistent with Main Control Board labels.

<u>Resolution</u>:

They will be made consistent with MCB labeling. Priority 2A.

12. CT Fan 57B switch says TRIP/CLOSE. It should be STOP/START.

<u>Resolution</u>:

It will be changed to STOP/START. Priority 3A.

13. It is possible for the keylock function on selector switches to hang up slightly as one goes from remote to local. If the operator stops there, it is possible for him to think he has reached the local position.

<u>Resolution</u>:

The key cannot be removed unless the switch is fully in Remote or Local. Therefore, the operator will know he has to move the switch back further. The operators will be made aware of the potential problem. Priority 3E.

14. Different keys are needed to operate different key locks located in the Remote Safe Shutdown Panel, the associated switchgear, and MCCs.

Resolution:

The keylocks will be changed to minimize the number of different keys needed during the use of the Remote Safe Shutdown System.

One key will operate all keylocks on the Remote Safe Shutdown Panel, a separate key will operate all keylocks on the MCC's, and another key will operate all the keylocks on the Switchgear. A maximum of 3 keys will be required in the emergency switchgear area on a per train basis. In the emergency DG Room, one key will operate all the keylocks on the DG panel and another key will operate all the keylocks on the disable panel. A maximum of 2 keys will be required inthe emergency DG Room on a per train basis. Priority 1A.

15. Power available lights should be white.

Resolution:

All power available lights will be white. Priority 2A.

16. All control switch handles on the Remote Safe Shutdown Panel, except the transfer switches, should be purple.

Resolution:

They will all be purple. Priority 2A.

17. Many labels on the panel are inconsistent with the identification used in the Remote Safe Shutdown Procedure.

Examples:

Emergency FW Valves - The labeling is not clear as to the function of these valves.

Pressurizer Backup Heaters - Check labeling for clarity and consistency.

Step 4 - CS-V65, SI-V138 - existing label is not clear as to the function of these valves.

Step 8 - PI-7335, 7336 - The procedure refers to these as RCS pressure. The label on the panel says pressurizer pressure. These should be checked for accuracy.

Step 11 - RC-FV-2894, 2896, 2832, 2833 - Tag Nos. on the panel do not agree with the Tag Nos. specified in the procedure.

Step 12a - CVS-V142, 143 should be labeled charging header isolation valves.

Step 12d - LCV-112B, C, E, and D should be changed to include CS (System Code).

Step 13b - Change nameplate for RC-V-122, 124 from "Pressure Relief MOV" to "PORV block valve"

Step 15a - Relabel PCCW Hx valve indicator lights to better indicate what they are (which is bypass, which is Hx inlet for PCCW).

Step 22 - "Accumulator relief valves" should read "accumulator vent valves". The Tag Nos. should be checked for accuracy.

Resolution:

These labels and/or procedures will be corrected for clarity and to be consistent between procedure and panels. Priority 1A.

18. LI-7446 - Boric acid tank level indicator is not on the panel (Steps 19 and 25). This should read in gallons, and be the same as the one in the Control Room.

Resolution:

This indicator is part of the design, and will be installed. Priority 1A.

19. The range of the pressurizer pressure indicator is not sufficient for the operator to complete the task of cooling down the plant.

Resolution:

The existing indicator will be replaced with a wider range indicator (0-2500 psig), which will allow the operator to monitor pressure (a required function) during the cooldown. Priority 1A.

P. CONTROL ROOM ARCHITECTURE

1. A method should be developed to insure that procedural documents will be returned to their rack in the proper order.

   Resolution:

   The plant will develop a method. Priority 2A.

2. The Unit Shift Supervisor's office does not have adequate voice contact with the primary operating area of the Control Room.

   Resolution:

   An intercom will be added to provide voice contact from the primary operating area to the Unit Shift Supervisor's office, the rest rooms, and the kitchen. These units should be located on the primary and secondary operator's desks. Priority 1A.

3. In the rest rooms and in the kitchen, an operator is out of voice contact with the operator in the primary control area.

   Resolution:

   An intercom will be added to provide this voice contact. Priority 1A.

Q. HEDS IDENTIFIED DURING ON-GOING REVIEW

1. Neutron Instrumentation System (NIS)

The Intermediate Range (IR) indicators are mounted high on the vertical section of the MCB causing parallax problems when reading the upper half of the scale. The operators are required to monitor this indicator during startup and ensure that there is at least a one-decade overlap between the power range indicators and the intermediate range indictors. With the present arrangement of indicators, this is difficult for an operator to monitor.

Resolution:

Interchange the Source Range (SR) startup rate indicator with the Intermediate Range (IR) flux level indicator and correct hierarchical labeling. This will move the IR indicator lower reducing the parallax problem. The SR startup rate indicator will generally indicate on the lower half of the scale; therefore, parallax will not be a problem in spite of moving it to a higher location. Priority 2A.

2. The indicators related to Main Feed Pump B on Section EF have "TG impulse chamber pressure", which is used to provide Steam Generator Program Level mixed in with them.

Resolution:

For this plant design, this is set at a constant 50%. The indication is not needed. Delete TG impulse chamber pressure and correct hierarchical labeling. Priority 3C.

3. The MSR indicators and associated control switches are not consistently laid out left to right.

Resolution:

The two indicators will be changed to provide proper correlation with the control switches. Priority 3C.

4. The "Tower Actuation" switch is located below the Tower Actuation Reset Switch. This is inconsistent with other system level actuation and reset switches.

Resolution:

The Tower Actuation Switch will be an oval handle SBM. The Tower Actuation Reset Switch is an OT2. The shape coding provides adequate differential between the switches. Priority 3E.

5. Westinghouse process control indicators are not laid out in a left to right orientation, Ch. I, Ch. II, Ch. III, and Ch. IV, for channel failure analysis and consistent orientation to match the existing bistable status light arrangement. This includes controlling signal switch placement.

Resolution:

A coded sticker will be placed on or near the indicators to indicate the correct channel. The controlling switch will be put under the channel it controls, and will be demarcated. Priority 3C.

6. The synch selector switches for the UAT and RAT breakers are reversed with their respective breaker switches.

Resolution:

Reverse the synch switch positions to reflect the physical location of the UAT and RAT breakers. Priority 2A.

7. For motor-operated valves, there is no way to tell if the motor thermal overload has actuated. In this situation, the indicating light(s) remains on, but the valve will not respond to actuation signals.

<u>Resolution</u>:

This problem should be addressed in a manner to provide the operator with information that the thermal overload has actuated. The Human Factors Team will review the resolution to insure it does not create another HED. Priority 2C.