Public Service
Electric and Gas
Company

Corbin A. McNeill, Jr.
Vice President -
Nuclear

Public Service Electric and Gas Company P.O. Box 236, Hancocks Bridge, NJ 08038 609 339-4800

March 17, 1986

Director of Nuclear Reactor Regulation
United States Nuclear Regulatory Commission
7920 Norfolk Avenue
Bethesda, Maryland 20814

Attention: Ms. Elinor Adensam, Director
Project Directorate 3
Division of BWR Licensing

Dear Ms. Adensam:

FINAL SAFETY ANALYSIS REPORT REVISIONS
HOPE CREEK GENERATING STATION
DOCKET NO. 50-354

Public Service Electric and Gas Company (PSE&G) hereby submits various revisions to the Hope Creek Generating Station (HCGS) Final Safety Analysis Report (FSAR). The attached revisions to the HCGS FSAR contain: 1) text changes due to the resolution of various Safety Evaluation Report (SER) Outstanding and Confirmatory Items; 2) revisions to maintain FSAR consistency with the Technical Specifications; 3) revisions to reconcile as-built plant discrepancies; and 4) general changes to the FSAR text, tables and figures.

Attachment 1 provides a brief summary and explanation for each change while Attachment 2 contains the actual marked-up sections of the FSAR. These revisions will be incorporated in FSAR Amendment 15 after fuel load but are being filed now in order to accurately reflect the design and operation of HCGS and support the issuance of an operating license. In addition, an affidavit is provided to affirm that the matters set forth in this transmittal are true and accurate.

This submittal supplements a similar transmittal from C.A. McNeill to E. Adensam dated March 3, 1986.

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1/1

Should you have any questions on the subject filing, do not hesitate to contact us.

Sincerely,

Cano

Affidavit
Attachments (2)

C D.H. Wagner
USNRC Licensing Project Manager

R.W. Borchardt
USNRC Senior Resident Inspector

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION
DOCKET NO. 50-354

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

FINAL SAFETY ANALYSIS REPORT
REVISIONS

Public Service Electric and Gas Company (PSE&G) hereby submits various revisions to the Hope Creek Generating Station (HCGS) Final Safety Analysis Report (FSAR). These HCGS FSAR revisions consists of text changes due to resolution of various Safety Evaluation Report (SER) Outstanding and Confirmatory Issues, revisions to maintain FSAR consistency with the Technical Specifications, revisions to reconcile as-built plant discrepancies, and general revisions to the FSAR text, tables and figures.

The matters set forth in these revisions are true and accurate to the best of my knowledge, information, and belief.

Respectfully submitted,

Public Service Electric

and Gas Company

By: Caw

Corbin A. McNeill, Jr.
Vice President - Nuclear

Sworn to and subscribed before me, a Notary Public of New Jersey, this 17th day of March 1986.

Deloris D. Hadden

DELORIS D. HADDEN
A Notary Public of New Jersey
My Commission Expires March 14, 1990

ATTACHMENT 1

SUMMARY OF CHANGES, ADDITIONS AND/OR MODIFICATIONS

1.10.2 (II.K.3.17)	Revision references 10CFR50.73 which discusses licensee event reports.
3.10.1.1.1 3.10.2.1 3.10.2.1.1 3.10.2.1.2 3.10.3.1 T3.10-3, pg. 1,3/6	Revisions are necessary to reference the appropriate IEEE standard and to show recommended changes according to the SQRT seismic methodology.
T3.11-4, pg. 20,51,53, 54,72/83 +	Revisions on pages 20, 54 and 72 were submitted to the NRC via a letter from PSE&G on February 25, 1986 - The Environmental Qualification Summary Report, Rev. 4-while pages 51 and 53 have been revised to include the amendment date, on the bottom of the page, when they were published.
T3.11-5, pg. 30/119 T3.11-6, pg. 2/3	Revisions add the feedwater cross-tie isolation valve, HV-4144, but exempt it from Environmental Qualification requirements since the valve has double breaker isolation and is not essential for a pipe break outside the drywell. Flooding of this valve by a feedwater line break in the steam tunnel does not affect the shutdown capability of the plant.
T3.11-6, pg. 1,2,3/3	Revisions add and delete various equipment to reflect information contained in the main steam tunnel flooding analysis. These revisions are consistent with Technical Specification Table 3.8.4.6-1 and supercede those provided to the NRC in a letter from C.A. McNeill to E. Adensam dated March 3, 1986.
4.6.1.2.4.2.a	Revision changes the condensate water pump suction filter absolute rating to reflect vendor documents.
5.4.6.2.5.1.r	Revision interchanges the valve tag numbers E51-LV-F005 and E51-HV-F004 to reflect the as-built plant conditions.

T5.4-2		Revisions change the setpoints for various RHR relief valves to reflect as-built plant design and delete the entries which are part of the steam condensing mode as the system is isolated by weld neck blind flanges.
F5.4-2 sh. 1/2 6.2.4.3.1.10 T6.2-16 pg. 3/33		Revisions change the normal valve position for the reactor recirculation water sample line from closed to open in order to comply with Technical Specification 3/4.4.4 which requires continuous sampling.
6.2.4.3.1.2 6.2.4.4.3 6.2.6.3 T6.2-16, pg. 1,33/33 T6.2-24, pg. 1/17 F6.2-28, sh. 2/48	+	Revisions clarify the feedwater line classification and testing as a result of the withdrawl of Appendix J Exemption Request #4. These revisions were previously submitted by C.A. McNeill to E. Adensam on March 11, 1986.
6.2.4.3.5 6.3.2.8		Revisions to these sections are necessary since an overly restrictive commitment exists requiring the locking closed of over 200 test, vent and drain valves. Per Question 480.20, the NRC indicated that SRP 6.2.4 requires branch lines from closed systems to be valved off and under administrative control. Hence the revisions are consistent with the SRP requirements. In addition, the revisions were confirmed with Mr. D. Wagner (NRC Project Manager) via phone call on January 7, 1986 and are consistent with the controls that are applied to those valves that are actually part of the primary containment pressure boundary.
T6.2-26 sh. 2,3/3		Revisions provide information on various relief valves which have been inadvertently left out of the table.
F6.2-45-48		These figures identify the extended containment boundaries for various systems. Changes to these figures are made to be consistent with Table 6.2-16; however, it is no longer necessary to revise these figures everytime a P&ID is updated since the P&ID is reproduced in the FSAR on another figure. The P&ID cross-reference is retained to assure proper source documentation.

6.4.2.2.e	Revision provides additional text for clarity.
6.4.3.2.b	Revision necessary to maintain consistency with Section 6.5.1.1.2.
6.4.4.1	Revision clarifies the comparisons between HPCI line breaks and main steam line breaks and are consistent with Tables 3.6-4, pg. 3/3, 12.2-7 through 11 and 15.6-14, as well as Section 15.6.4.5.1.2.
6.4.7.1.2	Revision corrects editiorial error and is necessary to maintain consistency with Section 6.4.7.1.1.
6.4.7.2	Revision necessary to correct editorial inconsistency.
6.8.1.1.a	Revision necessary to maintain consistency - with Tables 6.2-12 and 6.8-1.
9.1.3.2.4	Revision provides an additional phrase of text which was omitted in the printing process of Amendment 14.
9.1.5.2.2.11	Revision de-rates the capacity of the SACS pumps monorail from 15 tons to 4 tons since, per Section 9.1.5.3.3.11, the heaviest anticipated lift, the SACS pump motor, is 6160 lbs.
F9.3-9	Revision provides a new figure which shows the sodium pentaborate volume concentration requirements and is consistent with Technical Specification Surveillance 4.1.5.b and Figure 3.1.5-1.
T9.5-3, pg. 3/5	Revision adds nitrogen bottles to reflect P&ID M-11-1, sh. 3/3 (STACS) as the nitrogen is used to control water level in the supply and return accumulators.
11.2 11.2.1.j 11.2.2.1.1 11.2.2.1.2 11.2.3	Revisions are necessary to change the recycled liquid radwaste (LRW) demineralizer effluent water quality limit as it is transferred to the CST and normal makeup to the CST is demineralized water with a conductivity of less than or equal to 1.0 umho/cm (Section 9.2.3). Therefore, a greater quantity of treated LRW can be recycled without degrading the quality of water in the CST, less treated LRW will have to be discharged from the plant and less regenerant waste is created due to less frequent regeneration of the LRW demineralizers.

11.3.1.e		Revision correctly identifies when the continuous radioactivity monitors annunciate in the main control room.
11.5.2.2.3		Revision deletes seismic requirements from the FRVSV RMS as Regulatory Guide 1.97, Rev. 2 does not require seismic qualification, nor are other portions of the RMS seismically qualified as the system only provides a monitoring function.
T11.5-1, pg. 1/6		Revisions to various RMS detector ranges reflect vendor as-built equipment ranges previously not available.
12.1.3.2		Revisions are necessary to maintain consistency with Section 12.5.1.1.
13.1.2.2.6.a T13.1-4, pg. 28-31,80, 114-117/123		Revision deletes the resume of Mr. Thomas G. Busch as the individual is no longer filling the position of Technical Engineer. As shown in the text, the Senior Supervisors have assumed the responsibility for their areas of expertise. In addition, Mr. William J. Merritt's resume replaces Mr. Elmer J. Galbraith for the position of Senior Technical Supervisor due to personnel changes. Page 80 is editorial.
13.1.2.2.8.e F13.1-11	*	Revisions reflect a recent maintenance department reorganization which impacts summary statements made in SER Section 13.1.2.1(3), page 13-7, of Supplement 5.
13.1.3.1 T13.1-3, pg. 2/3 F13.1-11 13.2.1.1.1		Revisions necessary to reflect ANSI/ANS-3.1 manning criteria and implements various training requirements.
14.2.12.2		Revision necessary to correct editorial error in Amendment 14.
Q430.80	+*	Revision deletes the Technical Specification requirements for the cathodic protection system. This issue has been previously addressed in a letter from C.A. McNeill to E. Adensam on January 24, 1986 (Item #53) and impacts SER Section 9.5.4.2, page 9-64.

* These revisions impact the SER as noted
+ These revisions have previously been submitted to the NRC by PSE&G in a letter as noted

ATTACHMENT 2

The licensees should submit a report detailing outage dates and length of outages for all ECC systems for the last 5 years of operation, including causes of the outages. This report will provide the staff with a quantification of historical unreliability due to test and maintenance outages, which will be used to determine if a need exists for cumulative outage requirements in the technical specifications.

Based on the above guidance and clarification, a detailed report should be submitted. The report should contain (1) outage dates and duration of outages; (2) causes of the outage; (3) ECC systems or components involved in the outage; and (4) corrective action taken. Tests and maintanance outages should be included in the above listings which are to cover the last 5 years of operation. The licensee should propose changes to improve the availability of ECC equipment, if needed.

Applicants for an operating license shall establish a plan to meet these requirements.

Response

10CFR50.73 All unplanned ECCS outages are documented on site by incident reports, completed by the SNSS/NSS. These reports are used to generate licensee event reports (LERs) in accordance with ~~Chapter 16, Technical Specifications~~.

Planned ECCS outages are documented in the SNSS/NSS daily log. Analysis of failure trends is accomplished by means of the LER system, which requires a review of previous occurrences. Identified trends are further analyzed by the Safety Review Group and/or the Reliability and Assessment Group.

3.10 SEISMIC QUALIFICATION OF SEISMIC CATEGORY I INSTRUMENTATION AND ELECTRICAL EQUIPMENT

The seismic qualification of Seismic Category I instrumentation, electrical equipment, and their supports is described in this section. Sections 3.9.2.3, 3.9.2.4, 3.9.3.2, and 3.9.3.4 address similar topics on the seismic qualification, testing, and analysis of the Seismic Category I mechanical components, equipment, and their supports, including the integral or associated electrical components such as valve-mounted components and pump motors.

Dynamic testing methods and the results of the qualification of active pumps with motors and supports and pipe-mounted valves listed in Table 3.9-5 are addressed in Sections 3.9.3.2 and 3.9.3.4. All safety-related equipment will be investigated further to demonstrate compliance with the requirements for the seismic qualification review team (SQRT) of the NRC. Reports will be submitted to the NRC following the completion of these programs.

3.10.1 SEISMIC QUALIFICATION CRITERIA

3.10.1.1 Seismic Category I Equipment Identification

3.10.1.1.1 Seismic Category I NSSS Equipment Identification, Excluding Motors and Valve-Mounted Equipment

Seismic Category I nuclear steam supply system (NSSS) instrumentation and electrical equipment, as well as other equipment, is identified in Table 3.2-1.

All the plant Seismic Category I instrumentation and electrical equipment is qualified to resist and withstand the effects of the postulated earthquakes.

INSERT

The Class 1E ~~instrumentation and electrical equipment~~, (excluding motors and valve-mounted equipment), supplied by GE and requiring seismic qualification are identified in Table 3.10-3. The supporting structures for this equipment are identified in Table 3.10-4.

INSERT FOR PAGE 3.10-1

electrical and instrumentation equipment including the condensing chambers which are part of the pressure transmitter measuring system

demonstrate compliance with Regulatory Guide 1.100. However, the seismic qualification requirements used for this plant ensure an adequate degree of equipment performance and thereby represent an acceptable basis for qualifying the equipment.

INSERT A

Some equipment is shown to be qualified by single-axis and/or single-frequency testing. However, all essential equipment is reevaluated for seismic qualification according to the requirements or recommendations of IEEE 344-1975, Regulatory Guides 1.92 and 1.100, and Standard Review Plans 3.9.2, 3.10, and HCGS specific requirements as described in Table 3.10-3.

In most instances, use of single-axis test data is restricted to equipment with response that shows a predominant single mode of vibration in each direction with a minimal cross coupling. In some cases, if the response shows a single mode of vibration in each direction but also has cross coupling, the existing single-axis test data are still used if the test response spectra (TRS) can be shown to exceed the required response spectra (RRS) by a factor of 1.4 over all frequencies.

In most instances, use of single-frequency test data is restricted to cases where the required input motion is dominated by one frequency, where response of the equipment is adequately represented by one mode, or where the input motion has sufficient intensity and duration to produce sufficiently high levels of stress to assure structural integrity where structural integrity is the determinant requirement. In some cases, if the input motion is sufficiently high so as to excite secondary modes, such that modal responses can be shown to occur out of phase and at high enough levels, existing single-frequency test data are also used to demonstrate operability.

3.10.2.1.1 Procedures

INSERT B

GE-supplied Class 1E equipment meets the requirement that the qualification should demonstrate the capability to perform the required function during and after the effects of the safe shutdown earthquake (SSE). Both analysis and testing are used, but most equipment is tested. Analyses are ~~primarily~~ used, ~~to~~ determine the adequacy of mechanical strength, e.g., mounting bolts, etc, after operating capability is established by testing as follows:

INSERT C

a. Analysis - GE-supplied Class 1E equipment performing primarily a mechanical safety function, e.g., pressure boundary devices, etc, is analyzed since the passive nature of their critical safety role usually makes testing impractical. Analytical methods sanctioned by IEEE 344-1971 are used in such cases. See Table 3.10-3 for indication of which items were qualified by analysis.

b. Testing - GE-supplied Class 1E equipment having primarily an active electrical safety function is tested in compliance with IEEE 344-1971, Section 3.2.

3.10.2.1.2 Documentation

Available documentation verifies that the seismic qualification of GE-supplied Class 1E equipment is in accordance with the requirements of IEEE 344-1971, Section 4.

INSERT D

3.10.2.2 Testing Procedures for Qualifying NSSS Electrical Equipment and Instrumentation, Excluding Motors and Valve-Mounted Equipment

The test procedures require that the device be mounted on the table of the vibration machine in a manner similar to the actual mounting condition. The device is tested in the operating states as if it were performing its Class 1E functions. These states

INSERT FOR PAGE 3.10-4

and upgraded using SQRT program methodology

INSERT B FOR PAGE 3.10-4

utilizing SQRT program methodology, to demonstrate compliance with IEEE 344-1975. Also analysis to used to

INSERT C FOR PAGE 3.10-4a

Also, Class 1E equipment is analyzed to meet IEEE 344-1975 utilizing SQRT program methodology.

INSERT D FOR PAGE 3.10-4a

and IEEE 344-1975,

INSERT FOR PAGE 3.10-4

and upgraded using SQRT program methodology

INSERT B FOR PAGE 3.10-4

utilizing SQRT program methodology, to demonstrate compliance with IEEE 344-1975. Also analysis to used to

INSERT C FOR PAGE 3.10-4a

Also, Class 1E equipment is analyzed to meet IEEE 344-1975 utilizing SQRT program methodology.

INSERT D FOR PAGE 3.10-4a

and IEEE 344-1975,

The requirements of testing procedures and methods are in accordance with the project seismic specification and with IEEE 344-1975, Section 6. The tests are performed using a combination or one of the following techniques:

a. Proof testing

b. Fragility testing

c. Device testing

d. Assembly testing

e. Generic testing.

3.10.2.3.3 Combined Analysis and Testing

Equipment that cannot be qualified practically by analysis or testing because of its size and/or complexity is qualified by combined analysis and testing. Combined analysis and testing methods are in accordance with IEEE 344-1975, Section 7.

3.10.3 METHODS AND PROCEDURE OF ANALYSIS OR TESTING OF SUPPORTS OF ELECTRICAL EQUIPMENT AND INSTRUMENTATION

3.10.3.1 NSSS-Seismic Analysis Testing Procedures and Restraint Measures

The Class 1E equipment supplied by GE is used in many systems on many different plants under widely varying seismic requirements. The HCGS control room panels and local instrument panels are qualified for seismic adequacy by comparison to tested equivalent panels and devices by SQRT program methodology as described in Table 3.10-4.

INSERT

Some GE-supplied Class 1E devices are qualified by analysis only, as shown in Tables 3.10-3 and 3.10-4. Analysis is used for passive mechanical devices and is sometimes used in combination with testing for larger assemblies containing Class 1E devices.

INSERT FOR PAGE 3.10-8

for active devices in accordance with SQRT program methodologies and

TABLE 3.10-3

NSSS SEISMIC CATEGORY 1 ELECTRICAL AND INSTRUMENTATION EQUIPMENT QUALIFICATION RESULTS

Equipment	Method	Results
Temperature Elements	The temperature elements are qualified by both dynamic testing and analysis. The applicable standard is IEEE 344-1975.	The temperature elements designated as having an active safety function have been dynamically tested demonstrating qualification. Mounted similar to field conditions, they have been subjected to SRV vibration aging, chugging, seismic, and hydrodynamic loads. Biaxially testing, over the frequency range of 1 to 100 Hz, was accomplished in three mutually perpendicular axes with Test Response Spectra (TRS) enveloping the Required Response Spectra (RRS). The temperature elements maintained their functional and structural integrity during testing. Those elements having a passive safety function were analyzed to show structural integrity when subjected to process pressures and loads in excess of the requirement for their location.
Temperature Switch	The temperature switch is shown to be qualified by an analysis of its structural capability, THEREBY MEETING THE GUIDELINES OF IEEE 344-1975.	The safety function of the temperature switch is passive. Analysis shows that it exceeds its structural requirements when subjected to required seismic and hydrodynamic loads. Calculations indicate a high natural frequency making it a rigid body in the range of interest and its capability far exceeds its stress requirements.
Pressure Transmitters; Differential, Absolute, and Gauge	The transmitters are qualified by dynamic testing meeting the guidelines of IEEE 344-1975.	The transmitters can be subjected to both seismic and hydrodynamic loads during their installed life. Testing in an as-installed condition included random frequency excitation to meet SRV aging, upset and faulted seismic, and chugging requirements. Tests were performed in three mutually perpendicular axes. During testing the transmitters maintained structural integrity and met functional requirements.
Level Transmitters	Level transmitters are shown to be qualified for their application by both analysis and testing. Testing was performed to meet the guidelines of IEEE 344-1975.	The level transmitters have both an active or passive safety function depending on their application. Those transmitters with a passive safety function have been shown to meet structural requirement by analysis. They have natural frequencies higher than the range of interest and have been shown to have structural integrity to withstand the required seismic and dynamic conditions.

Insulated Detectors	The detectors have been qualified by dynamic testing to meet the guidelines of IEEE 344-1975.	Detectors have an active safety function and met structural and functional requirements when subjected to seismic testing at amplitudes greater than required. Five OBE and one SSE biaxial random tests were performed in three mutually perpendicular axes over a frequency range of 1 to 100 Hz. Functional performance was demonstrated before, during, and after seismic excitation.
IRM Detector	A combination of test and analysis demonstrates qualification of the detectors for their installed location TO MEET THE GUIDELINES OF IEEE 344-1975.	The IRM detector movement during a seismic event is controlled by the fuel bundle and maximum excitation occurs at the natural frequency of the bundle. The detector was tested at discrete frequencies in the horizontal axes and analyzed for vertical loads. Capabilities, both tested and analyzed, exceed the requirements, demonstrating qualification.
Conductivity Element	The conductivity cell was analyzed to withstand seismic loads significantly greater than required TO MEET THE GUIDELINES OF IEEE 344-1971	The safety function of the cell is passive, however, it must maintain its structural integrity. Analysis indicates no resonances in any axis below 100 Hz and the ability to withstand loads more than 15 times greater than required.
Condensing Chamber	This equipment is qualified by analysis to meet the HCGS seismic requirement applying the ASME Boiler and Pressure Vessel Code Section III.	Stress analysis indicates that the condensing chamber meets the requirements of the ASME code and that the lowest calculated allowable moment reaction exceeds the maximum moment of any condensing chamber installation.

P.O. # M141(Q) Component: Nuclear Relief Valves Manufacturer: Crosby Valve & Gage Company

I.D. No.	Model No.	Functional Description	Location
1 FD PSV F076	Style: VR	HPCI Vacuum Breaker Line	Reactor Bldg. EL 077'
1 FD PSV F077	Style: VR	HPCI Vacuum Breaker Line	Reactor Bldg. EL 077'
1 FC PSV F063	Style: VR	RCIC Turbine Exhaust Valve	Reactor Bldg. EL 077'
1 FC PSV F064	Style: VR	RCIC Turbine Exhaust Valve	Reactor Bldg. EL 077'
1 BF PSV 4003	Style: VR	Disch. Vol. Vent'n (Vac. Bkr.)	Reactor Bldg. El. 102'
~~1 KP PSV 5832A~~	~~Style: JMBU~~	~~MSIV Inboard Seal Gas Supply~~	~~Reactor Bldg. EL 102'~~
~~1 KP PSV 5832B~~	~~Style: JMBU~~	~~MSIV Outboard Seal Gas Supply~~	~~Reactor Bldg. EL 102'~~
1 AB PSV 4504A	JO-25-SPL +	SRV PSV F013A Acc. Relief Valve	Drywell Torus, Reactor Bldg. El. 121'
1 AB PSV 4504B	JO-25-SPL +	SRV PSV F013B Acc. Relief Valve	Drywell Torus, Reactor Bldg. El. 121'
1 AB PSV 4504C	JO-25-SPL +	SRV PSV F013C Acc. Relief Valve	Drywell Torus, Reactor Bldg. El. 121'
1 AB PSV 4504D	JO-25-SPL +	SRV PSV F013D Acc. Relief Valve	Drywell Torus, Reactor Bldg. El. 121'
1 AB PSV 4504E	JO-25-SPL +	SRV PSV F013E Acc. Relief Valve	Drywell Torus, Reactor Bldg. El. 121'
1 AB PSV 4504F	JO-25-SPL +	SRV PSV F013F Acc. Relief Valve	Drywell Torus, Reactor Bldg. El. 121'
1 AB PSV 4504G	JO-25-SPL +	SRV PSV F013G Acc. Relief Valve	Drywell Torus, Reactor Bldg. El. 121'
1 AB PSV 4504H	JO-25-SPL +	SRV PSV F013H Acc. Relief Valve	Drywell Torus, Reactor Bldg. El. 121'

+ MODEL NO. SHOWN IS GENERIC IDENTIFIER ONLY. THE UNIQUE VALVE DATA SHEET SHOULD BE CHECKED FOR SUPPLEMENTAL PARAMETERS AND CHARACTERISTICS.

P.O. # P301(Q) Component: Large Valves Manufacturer: Anchor Darling Valve Co.

I.D. No.	Model No.	Functional Description	Location
1HBHV F003 G14	Not Applicable	Isln Closure Signal Valve	Drywell Torus, Reactor Bldg. EL 077'
1HBHV F004 G14	Not Applicable	Isln Closure Signal Valve	Reactor Bldg. EL 077'
1HFHV F019 G14	Not Applicable	Drywell Equip Drain Sump Pump	Drywell Torus, Reactor Bldg. EL 077'
1HBHV F020 G14	Not Applicable	Drywell Equip Drain Sump Pump	Reactor Bldg. EL 077'
1HBHV 5262	Not Applicable	RB/Drywell Dr To Dr Coll Tk	Reactor Bldg. EL 077'
1HBHV 5275	Not Applicable	RB/Drywell Dr to Waste Coll Tk	Reactor Bldg. EL 077'
1HCHV 5551	Not Applicable	Reactor Bldg Isln Valve Unit 1	Reactor Bldg. EL 132'
1KAHV 7626	Not Applicable	Reactor Bldg Isolation	Reactor Bldg. EL 077'
1KBHV 7629	Not Applicable	Reactor Bldg Isolation	Reactor Bldg. EL 077'
1KCHV 3408M	Not Applicable	Sys 1PD3-1PD11 Isln Valve 1V049	Reactor Bldg. EL 077'
1 KH HV 5035	Not Applicable	RB Nitrogen Sply Valve	Reactor Bldg. EL 077'
1 EG HV 2325H	Not Applicable	Core Spray Pump Rm Unit Cls	Reactor Bldg. EL 054'
1 ECV 015	Not Applicable	Check Valve (8"-HCC-CK) [P&ID 53.1, M.R. No. 15.7]	Reactor Bldg. El. 054'
1 BCV 038	Not Applicable	Testable Check Valve (6"-GBB-TCK) [P&ID 51-1, M.R. No. 3.9]	Reactor Bldg. El. 054'

P.O. # P301(Q) Component: Large Valves Manufacturer: Anchor Darling Valve Co.

I.D. No.	Model No.	Functional Description [Misc. Data]	Location
1 APV 055	Not Applicable	Testable Check Valve (4"-GBB-TCK) [P&ID 51-1, M.R. No. 3.3]	Reactor Bldg. El. 102'
1 APV 057	Not Applicable	Testable Check Valve (4"-GBB-TCK) [P&ID 51-1, M.R. No. 3.3]	Reactor Bldg. El. 102'
1 APV 058	Not Applicable	Testable Check Valve (4"-GBB-TCK) [P&ID 51-1, M.R. No. 3.3]	Reactor Bldg. El. 102'
1 BCV 024	Not Applicable	Testable Check Valve (4"-GBB-TCK) [P&ID 51-1, M.R. No. 3.3]	Reactor Bldg. El. 054'
1 BCV 030	Not Applicable	Testable Check Valve (4"-GBB-TCK) [P&ID 51-1, M.R. No. 3.3]	Reactor Bldg. El. 054'
1 BCV 033	Not Applicable	Testable Check Valve (4"-GBB-TCK) [P&ID 51-1, M.R. No. 3.3]	Reactor Bldg. El. 054'
1 BCV 127	Not Applicable	Testable Check Valve (4"-GBB-TCK) [P&ID 51-1, M.R. No. 3.3]	Reactor Bldg. El. 054'
1 BCV 130	Not Applicable	Testable Check Valve (4"-GBB-TCK) [P&ID 51-1, M.R. No. 3.3]	Reactor Bldg. El. 102'
1 BCV 163	Not Applicable	Testable Check Valve (4"-GBB-TCK) [P&ID 51-1, M.R. No. 3.3]	Reactor Bldg. El. 102'
1 APV 039	Not Applicable	Testable Check Valve (3"-GBB-TCK) [P&ID 52-1, M.R. No. 3.1]	Reactor Bldg. El. 102'
1 APV 040	Not Applicable	Testable Check Valve (3"-GBB-TCK) [P&ID 52-1, M.R. No. 3.1]	Reactor Bldg. El. 102'
1 APV 060	Not Applicable	Testable Check Valve (3"-GBB-TCK) [P&ID 52-1, M.R. No. 3.1]	Reactor Bldg. El. 102'
1 APV 061	Not Applicable	Testable Check Valve (3"-GBB-TCK) [P&ID 52-1, M.R. No. 3.1]	Reactor Bldg. El. 102'
1 BEV 028	Not Applicable	Testable Check Valve (3"-GBB-TCK) [P&ID 52-1, M.R. No. 3.1]	Reactor Bldg. El. 054'

P.O. # P301(Q) Component: Large Valves Manufacturer: Anchor Darling Valve Co.

I.D. No.	Model No.	Functional Description [Misc. Data]	Location
1 BEV 030	Not Applicable	Testable Check Valve (3"-GBB-TCK) [P&ID 52-1, M.R. No. 3.1]	Reactor Bldg. El. 054'
1 BEV 032	Not Applicable	Testable Check Valve (3"-GBB-TCK) [P&ID 52-1, M.R. No. 3.1]	Reactor Bldg. El. 054'
1 BEV 034	Not Applicable	Testable Check Valve (3"-GBB-TCK) [P&ID 52-1, M.R. No. 3.1]	Reactor Bldg. El. 054'
1 BDV 002	Not Applicable	Testable Check Valve (6"-HBB-TCK) [P&ID 49-1, M.R. No. 7.5]	Reactor Bldg. El. 054'
1 BDV 004	Not Applicable	Testable Check Valve (6"-HBB-TCK) [P&ID 49-1, M.R. No. 7.5]	Reactor Bldg. El. 054'
1 FCV 003	Not Applicable	Testable Check Valve (10"-HBB-TCK) [P&ID 49-1, M.R. No. 7.7]	Reactor Bldg. El. 054'
1 BJV 006	Not Applicable	Testable Check Valve (16"-HBB-TCK) [P&ID 55-1, M.R. No. 7.9]	Reactor Bldg. El. 054'
1 BJV 008	Not Applicable	Testable Check Valve (16"-HBB-TCK) [P&ID 55-1, M.R. No. 7.9]	Reactor Bldg. El. 054'
1 FDV 004	Not Applicable	Testable Check Valve (20"-HBB-TCK) [P&ID 55-1, M.R. No. 7.11]	Reactor Bldg. El. 054'
1 BCV 023	NOT APPLICABLE	RHR TO FUEL POOL	REACTOR BLDG. El. 102'

P.O. # P303A(Q) Component: Small Valves Manufacturer: Rockwell International

I.D. No.	Model No.	Functional Description [Misc. Data]	Location
1 BCV 089	838YT1	Check Valve (1"-EBA-CK) [P&ID 51-1, M.R.-No. 9.1]	Reactor Bldg. El. 057'
1 BCV 090	838YT1	Check Valve (1"-EBA-CK) [P&ID 51-1, M.R.-No. 9.1]	Reactor Bldg. El. 057'
1 BCV 194	838YT1	Check Valve (1"-EBA-CK) [P&ID 51-1, M.R.-No. 9.1]	Reactor Bldg. El. 056'
1BC HV 5055A	3624-MT	Valve from RHR HX to Hydrogen Recombiner	Rector Bldg. EL 058'
1BC HV 5055B	3624-MT	Valve from RHR HX to Hydrogen Recombiner	Reactor Bldg. EL 090'
1GS HV 5057A	3624-MT	Valve from RHR HX to Hydrogen Recombiner	Reactor Bldg. EL 058'
1GS HV 5057B	3624-MT	Valve from RHR HX to Hydrogen Recombiner	Reactor Bldg. EL 090'
1 BCV 308	838YT1	Check Valve (2"-EBA-CK) [P&ID 52-1, M.R. Item No. 9.5]	Reactor Bldg. El. 056'
1 BCV 309	838YT1	Check Valve (2"-EBA-CK) [P&ID 52-1, M.R. Item No. 9.5]	Reactor Bldg. El. 056'
1 BCV 312	838YT1	Check Valve (2"-EBA-CK) [P&ID 52-1, M.R. Item No. 9.5]	Reactor Bldg. El. 056'
1 BCV 313	838YT1	Check Valve (2"-EBA-CK) [P&ID 52-1, M.R. Item No. 9.5]	Reactor Bldg. El. 056'
1 BCV 423	838YT1	Check Valve (2"-EBA-CK) [P&ID 10-1, M.R. Item No. 9.5]	Reactor Bldg. El. 108'
~~1 BCV 023~~	~~838YT1~~	~~Check Valve (2"-EBA-CK) [P&ID 50-1, M.R. Item No. 9.5]~~	~~Reactor Bldg. El. 061'~~

HCGS FSAR
TABLE 3.11-5

EQUIPMENT SELECTED FOR HARSH ENVIRONMENT QUALIFICATION

P&ID
M-41-1

SYSTEM: NUCLEAR BOILER
AB

P.O.	ID No. Note (5)	MPL NO.	COMPONENT	LOCATION BLDG.	LOCATION ELEV.	PAM EQUIP. NOTE (1)	TMI ACTION PLAN EQUIP. NOTE (2)	EESS REF. NO.
J556Q	1-AB-TE-3648A		Temp. Elemt.	Reactor	54	Yes	No	43
J556Q	1-AB-TE-3648B		Temp. Elemt.	Reactor	54	Yes	No	43
J556Q	1-AB-TE-3648C		Temp. Elemt.	Reactor	54	Yes	No	43
J556Q	1-AB-TE-3648D		Temp. Elemt.	Reactor	54	Yes	No	43
M001	1-SN-SV-3652A	B21-F013	Solenoid Valve	Reactor	121	No	No	159
M001	1-SN-SV-3652B	B21-F013	Solenoid Valve	Reactor	121	No	No	159
M001	1-SN-SV-3653A	B21-F013	Solenoid Valve	Reactor	121	No	No	159
M001	1-SN-SV-3653B	B21-F013	Solenoid Valve	Reactor	121	No	No	159
M001	1-SN-SV-3654A	B21-F013	Solenoid Valve	Reactor	121	No	No	159
M001	1-SN-SV-3654B	B21-F013	Solenoid Valve	Reactor	121	No	No	159
M001	1-SN-SV-3655A	B21-F013	Solenoid Valve	Reactor	121	No	No	159
M001	1-SN-SV-3655B	B21-F013	Solenoid Valve	Reactor	121	No	No	159
M001	1-SN-SV-3656A	B21-F013	Solenoid Valve	Reactor	121	No	No	159
M001	1-SN-SV-3657A	B21-F013	Solenoid Valve	Reactor	121	No	No	159
M001	1-SN-SV-3658A	B21-F013	Solenoid Valve	Reactor	121	No	No	159
M001	1-SN-SV-3659A	B21-F013	Solenoid Valve	Reactor	121	No	No	159
M001	1-SN-SV-3660A	B21-F013	Solenoid Valve	Reactor	121	No	No	159
M001	1-SN-SV-3661A	B21-F013	Solenoid Valve	Reactor	121	No	No	159
M001	1-SN-SV-3662A	B21-F013	Solenoid Valve	Reactor	121	No	No	159
M001	1-SN-SV-3663A	B21-F013	Solenoid Valve	Reactor	121	No	No	159
M001	1-SN-SV-3664A	B21-F013	Solenoid Valve	Reactor	121	No	No	159
M001	1-SN-SV-3665A	B21-F013	Solenoid Valve	Reactor	121	No	No	159
M001	1-SN-SV-3665B	B21-F013	Solenoid Valve	Reactor	121	No	No	159
J800Q	1-AB-XE-4507A		Acoustic Elemt.	Reactor	121	Yes	Yes	51
J800Q	1-AB-XT-4507A		Acoustic Trans.	Reactor	102	Yes	Yes	50
J800Q	1-AB-XE-4507B		Acoustic Elemt.	Reactor	121	Yes	Yes	51
J800Q	1-AB-XT-4507B		Acoustic Trans.	Reactor	102	Yes	Yes	50
J800Q	1-AB-XE-4507C		Acoustic Elemt.	Reactor	121	Yes	Yes	51
J800Q	1-AB-XT-4507C		Acoustic Trans.	Reactor	102	Yes	Yes	50
J800Q	1-AB-XE-4507D		Acoustic Elemt.	Reactor	121	Yes	Yes	51
J800Q	1-AB-XT-4507D		Acoustic Trans.	Reactor	102	Yes	Yes	50
J800Q	1-AB-XE-4507E		Acoustic Elemt.	Reactor	121	Yes	Yes	51
J800Q	1-AB-XT-4507E		Acoustic Trans.	Reactor	102	Yes	Yes	50
J800Q	1-AB-XE-4507F		Acoustic Elemt.	Reactor	121	Yes	Yes	51
P303AQ	1-AE-HV-4144		CONTROL VALVE	REACTOR	102	No	No	139

SAFETY-RELATED EQUIPMENT LOCATED IN A HARSH ENVIRONMENT EXEMPTED
FROM ENVIRONMENTAL QUALIFICATION REQUIREMENTS

EQUIPMENT TAG NO.	MPL NO.	DESCRIPTION	REASON
1 AVE 261		Electric Duct Heater, SLC	Due to reactor building temperature increase during a DBA, the duct heaters will not function due to the temperature control settings, which is below DBA building, temperature. The heater circuits are protected by primary and backup CLASS 1E ~~breakers~~ PROTECTIVE DEVICES.
1 BVE 261		Electric Duct Heater, SLC	
10 VE 259		Electric Duct Heater, RCIC	
10 VE 260		Electric Duct Heater, HPCI	
1 AN 205		4.16 KV Breaker - RRS Pump Motor	The RRS pump motor breakers trip upon receipt of a LOCA signal shutting down the pump. The breakers are no longer required to perform a safety-related function.
1 BN 205		4.16 KV Breaker - RRS Pump Motor	
1 CN 205		4.16 KV Breaker - RRS Pump Motor	
1 DN 205		4.16 KV Breaker - RRS Pump Motor	
10 Y 201		Panel	These panels and transformers are located in the reactor building and feed non-critical class 1E loads. They are protected by primary and backup 1E breakers.
10 Y 202		Panel	
10 Y 203		Panel	
10 Y 204		Panel	
10 X 201		Transformer	
10 X 202		Transformer	
10 X 203		Transformer	
10 X 204		Transformer	
1-SK-TE-N016		Temperature Elements	These temperature elements are not qualified for submergence caused by a feedwater line break in the steam tunnel. They have been provided with primary and backup 1E bus protective devices located in the hazard free area.
1-SK-TE-N012A		Temperature Elements	
1-SK-TE-N012C		Temperature Elements	
1-SK-TE-N010A		Temperature Elements	
1-SK-TE-N010B		Temperature Elements	
1-SK-TE-N010C		Temperature Elements	
1-SK-TE-N010D		Temperature Elements	
1-SK-TE-N012B		Temperature Elements	
1-SK-TE-N012D		Temperature Elements	

SAFETY-RELATED EQUIPMENT LOCATED IN A HARSH ENVIRONMENT EXEMPTED
FROM ENVIRONMENTAL QUALIFICATION REQUIREMENTS

EQUIPMENT TAG NO.	MPL NO.	DESCRIPTION	REASON
1-AE-HV-F039		Motor Operated Valves	These motor operated valves AND SOLENOID VALVES are not qualified for submergence caused by a feedwater line break in the steam tunnel. They have been provided with primary and backup 1E bus protective devices located in the hazard free area.
1-AB-HV-F071		Motor Operated Valves	
1-KP-HV-5829A,B		Motor Operated Valves	
1-KP-HV-4834A,B		Motor Operated Valves	
1-KP-HV-5835A,B		Motor Operated Valves	
1-KP-HV-5836A,B		Motor Operated Valves	
1-KP-HV-5837A,B		Motor Operated Valves	
~~1-AB-HV-F067A~~		~~Motor Operated Valves~~	
~~1-AB-HV-F067B~~		~~Motor Operated Valves~~	
~~1-AB-HV-F067C~~		~~Motor Operated Valves~~	
~~1-AB-HV-F067D~~		~~Motor Operated Valves~~	
1-AE-HV-4144		MOTOR OPERATED VALVES	
No Tag No.	C11-F010	Position Switch	These NAMCO limit switches perform no safety functions. Failure modes and effect analysis has shown that there are no possible failure modes which can adversely effect the 1E power supply.
No Tag No.	C11-F011	Position Switch	
No Tag No.	C11-F180	Position Switch	
No Tag No.	C11-F181	Position Switch	
1-BE-SV-F006A	E21	Solenoid Valve	These solenoid valves and position switches perform no safety functions. However, because of their association with a 1E power supply, they have been provided with primary and backup protective devices.
No Tag No.	E21-F006A	Position Switch	
1-BE-SV-F006B	E21	Solenoid Valve	
No Tag No.	E21-F006B	Position Switch	
1-BC-SV-F041A	E11	Solenoid Valve	
No Tag No.	E11-F041A	Position Switch	
1-BC-SV-F041B	E11	Solenoid Valve	
No Tag No.	E11-F041B	Position switch	
1-BC-SV-F041C	E11	Solenoid Valve	
No Tag No.	E11-F041C	Position Switch	

SAFETY-RELATED EQUIPMENT LOCATED IN A HARSH ENVIRONMENT EXEMPTED
FROM ENVIRONMENTAL QUALIFICATION REQUIREMENTS

EQUIPMENT TAG NO.	MPL NO.	DESCRIPTION	REASON
1-BC-SV-F041D	E11	Solenoid Valve	These solenoid valves and position switches perform no safety functions. However, because of their association with a 1E power supply, they have been provided with primary and backup protective devices.
No Tag No.	E11-F041D	Position Switch	
1-BC-SV-F050A	E11	Solenoid Valve	
No Tag No.	E11-F050A	Position Switch	
1-BC-SV-F050B	E11	Solenoid Valve	
No Tag No.	E11-F050B	Position Switch	
10-P-212		RCIC Vac Pump Motor Space Heater	They are protected by primary and backup 1E breakers.
10-P-2[illegible]		RCIC Gland Seal Cond. Motor Space Heater	
1-FC-TSH-4277		Temp. Switch High	Provide alarm function only. Determined by analysis that no fault condition (ground, open or short circuit) can impact the 125V dc safety related power bus.
1-FC-TSH-4278		Temp. Switch High	
1-FC-LSH-4288		Level Sw. High	
1-FC-HV-4282		Motor Operated Valve	This RCIC system motor operated valve performs no safety function. However, because of its association with a Class 1E power supply, it has been provided with Class 1E primary and backup protective devices.
10-P-213(Sp. Htr.)		HPCI Aux. Oil Pump Motor Space Heater	They are protected by primary and backup 1E breakers.
10-P-215(Sp. Htr.)		HPCI Gland Seal Cond. Motor Space Heater	
10-P-216(Sp. Htr.)		HPCI Vac. Pump Motor Space Heater	

Note: All of the equipment in this table is qualified for its function in In accordance with 10CFR50.49 requirements.

a. Drive water pump - The drive water pump pressurizes the system with water from the condensate treatment system and/or the condensate storage tank (CST). One spare pump is provided for standby. A discharge check valve prevents backflow through the standby pump. A portion of the pump discharge flow is diverted through a minimum flow bypass line to the CST. This flow is controlled by an orifice and is sufficient to prevent pump damage if the pump discharge is inadvertently closed.

Condensate water is processed by two sets of filters in the system. The pump suction filters are disposable-
50 element type with a ~~[illegible]~~-micron absolute rating. A 250-micron strainer is provided at the inlet of each suction filter to reduce the debris loading on the suction filter elements. A 250-micron strainer in the suction filter bypass line protects the pump when both suction filters are out of service. The drive water filters downstream of the pump are cleanable-element type with a 50-micron absolute rating. A 250-micron strainer in each drive water filter discharge line protects the hydraulic system if there is a filter element failure. Local differential pressure indicators and main control room alarms monitor the filter elements as they collect foreign material.

b. Accumulator charging pressure - Accumulator charging pressure is established by precharging the nitrogen accumulator to a precisely controlled pressure at a known temperature. During a scram, the scram inlet and outlet valves open and permit the stored energy in the accumulators to discharge into the drives. The resulting pressure decrease in the charging water header allows the CRD drive water pump to run out, i.e., allows the flow rate to increase substantially, into the CRDs via the charging water header. The flow element upstream of the accumulator charging header senses the high flow and provides a signal to the manual/auto flow-control station, which in turn closes the system flow-control valve. This action maintains increased flow through the charging water header, while avoiding prolonged pump operation at run-out conditions.

Pressure in the charging header is monitored with a local pressure indicator and a main control room high pressure alarm.

requires one to be out of the main control room. Administrative control minimizes subsequent checks.

i. Verify that water is available in the CST.

j. Verify that oil is available in RCIC turbine oil reservoir and that the turbine and pump are ready to run as defined by the technical manuals for the turbine and pump.

k. During extended periods of operation and when the normal water level is again reached, the HPCI system may be manually tripped, and the RCIC system flow controller may be adjusted and switched to manual operation. This prevents unnecessary cycling of the two systems. Should automatic shutdown of the RCIC system occur due to high water level in the RPV, the system will automatically restart on recurrence of low water level. Trips of the RCIC system due to other conditions must be operator-controlled. If the RCIC flow is inadequate, HPCI flow is initiated automatically by a low water level signal.

l. Adjust the flow controller setpoint as required to maintain desired reactor water level.

m. When RCIC operation is no longer required, manually trip the RCIC system and turn the flow controller back to automatic.

n. Close the turbine steam supply valve, E51-HV-F045 and reset the flow setpoint.

o. Reset the turbine trip throttle valve.

p. Stop the barometric condenser vacuum pump.

q. Close the cooling water supply valve E51-HV-F046.

E51-HV-F004

r. Verify that valves ~~E51-LV-F005~~, E51-HV-F025, and E51-HV-F026 reopen automatically after valve

E51-LV-F005

E51-HV-F045 is closed. Valve ~~E51-HV-F004~~ opens as required by signal from barometric condenser.

s. Verify that the system is in the standby configuration as shown on Figures 5.4-8 and 5.4.-9.

5.4.6.2.5.2 Test Loop Operation

This operating mode is manually initiated by the operator. Operator action is required as defined below:

a. Complete the verification made in steps a. through j. of Section 5.4.6.2.5.1.

b. Position all motor-operated valves as shown on Figures 5.4-8 and 5.4-9.

c. Open E51-FV-F059 and E51-HV-F022 fully.

d. Start the barometric condenser vacuum pump.

e. Open E51-HV-F046.

f. Open E51-HV-F045.

g. Verify that valves E51-HV-F004, E51-LV-F005, E51-HV-F025, and E51-HV-F026 are automatically closed after valve E51-HV-F045 is opened.

h. Adjust E51-HV-F022 to obtain a pump discharge pressure of 300 psig.

i. Observe turbine rpm on speed indicator.

j. Turn the remote-manual switch for E51-HV-F019 to the open position, and release. Observe that valve E51-HV-F019 cycles are fully open and closed by watching position lights. Also observe the turbine

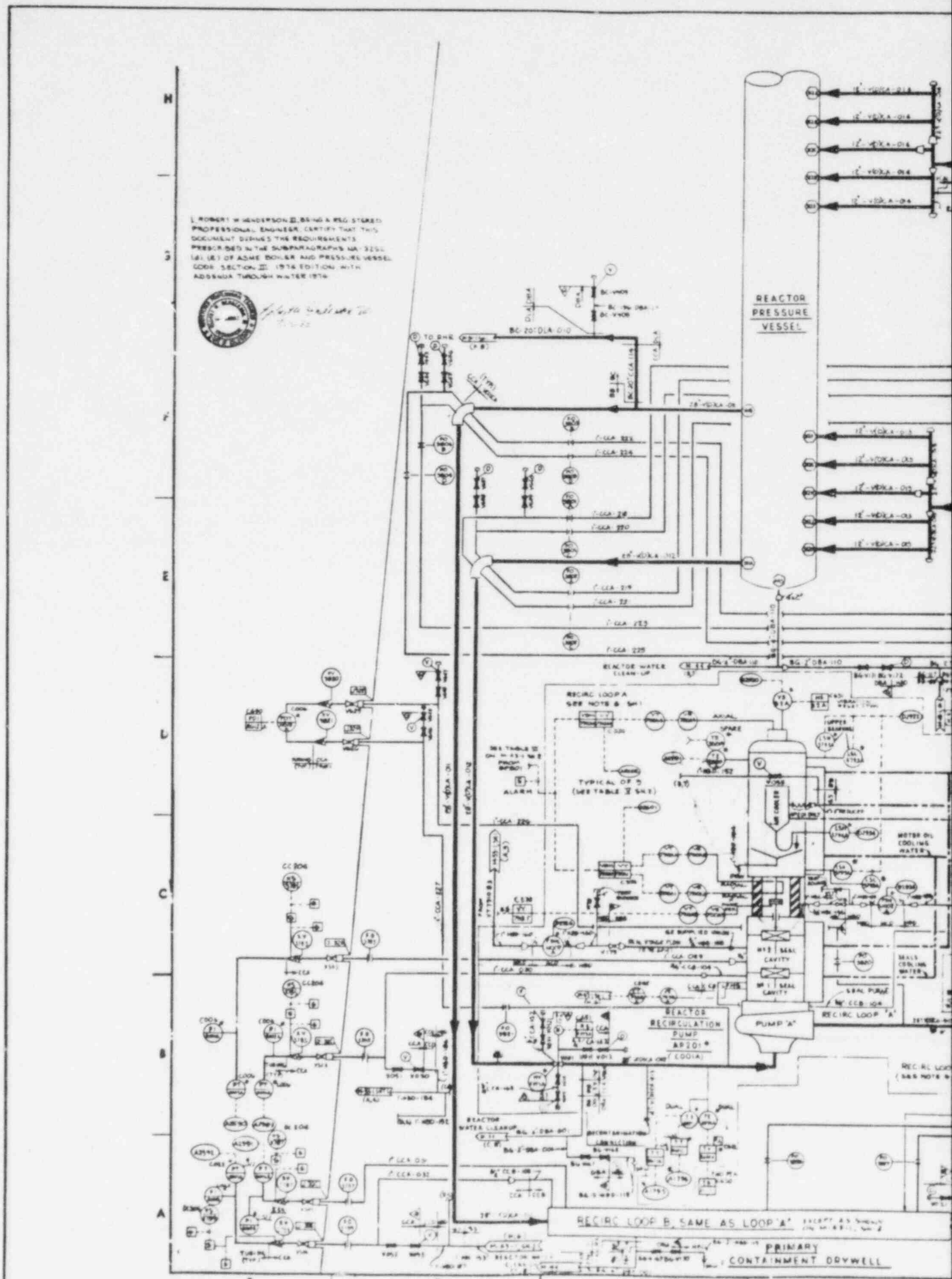
TABLE 5.4-2

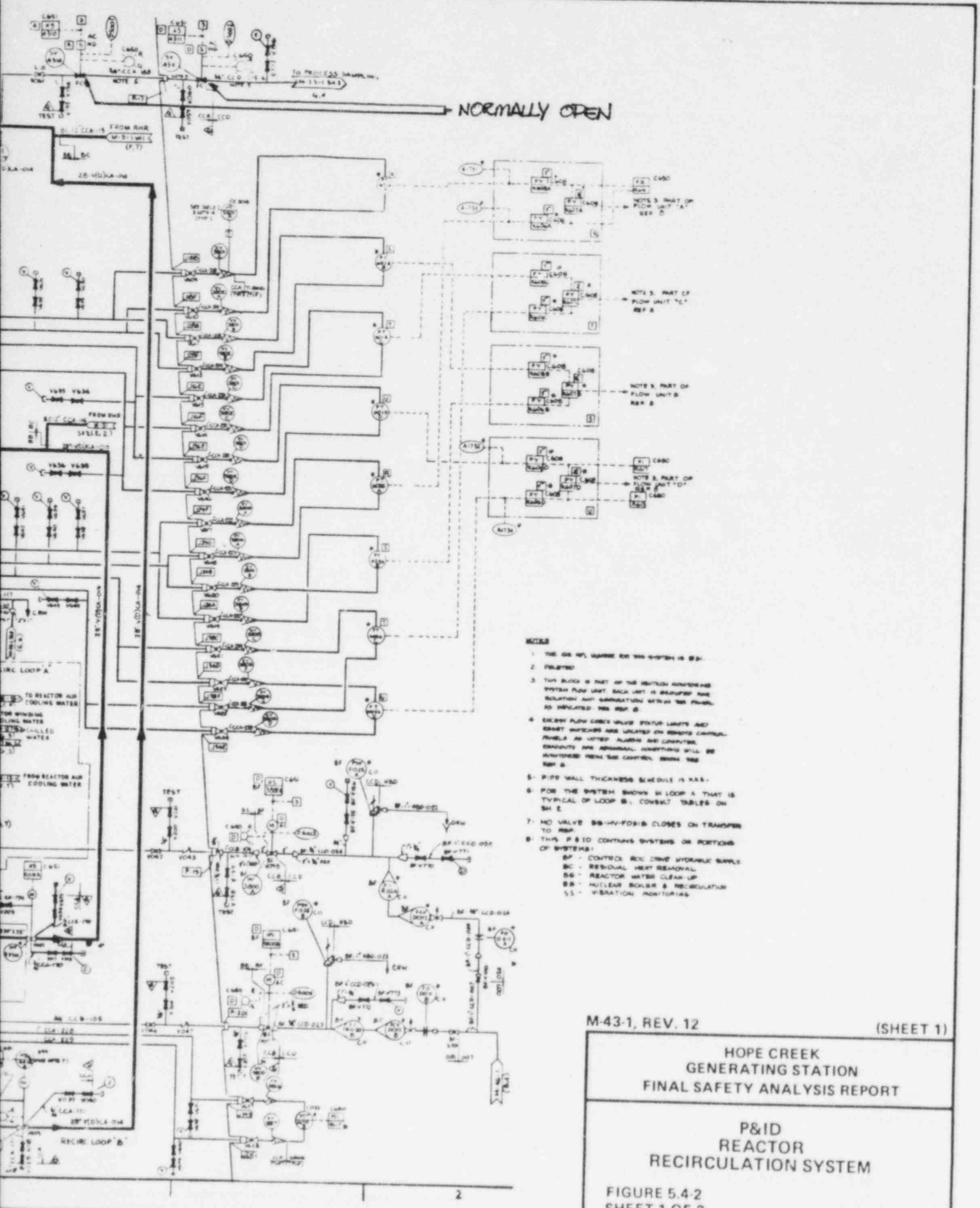
RHR SYSTEM RELIEF VALVE DATA

Valve Location	Valve	Setpoint psig	Capacity gpm(1)	Method of Collection(3)
Shutdown cooling suction line (outside containment)	PSV-F029	~~440~~ 170	10	DRW
Pump suction line	PSV-F030 A,B,C&D	~~440~~ 170	10	DRW
Heat exchanger inlet line(4)	PSV-F055 A,B	~~410~~	~~360,000 lb/h~~	~~Suppression pool~~
Heat exchanger outlet line to RCIC(4)	PSV-F097	~~60~~	~~750~~	~~Suppression pool~~
Pump discharge line	PSV-F025 A,B,C,D	410	10	Suppression pool
Heat exchanger (shell side)(2)	PSV-4431 A,B	410	Thermal relief only	Suppression pool
Thermal relief valve on shutdown cooling suction line (inside containment)	PSV-4425	1250 ~~1000~~	0.1	DRW
Heat exchanger vent vacuum breaker (4)	PSV-151 A,B PSV-152 A,B	~~0.5 psid~~	~~1152 scfm~~	~~Suppression pool~~

(1) Capacity is based on setpoint plus 10% accumulation.
(2) GE-supplied valves.
(3) ~~CRW = clean radwaste collection;~~ DRW = dirty radwaste collection.
(4) Deactivated as a consequence of RHR steam condensing mode elimination.

FOR INFORMATION ONLY





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(SHEET 1)

HOPE CREEK
GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

P&ID
REACTOR
RECIRCULATION SYSTEM

FIGURE 5.4-2
SHEET 1 OF 2

Amendment 14, 01/86

The MSIV sealing system is divided into two independent subsystems. The inboard subsystem maintains a seal between the two MSIVs, and the redundant outboard subsystem maintains a seal between the outboard MSIV and the MSSV. Sealing is accomplished by maintaining a higher pressure in the main steam lines than in the containment. The operation of the MSIV sealing system is discussed in Section 6.7.

A main steam drain line connects to the main steam lines between the two MSIVs on each main steam line outside of the primary containment. Isolation of this line is provided by the inboard MSIV and by a motor-operated globe valve in the drain line that automatically closes upon receipt of a containment isolation signal.

6.2.4.3.1.2 Feedwater Lines

CONTAINMENT ISOLATION

PER LINE

The portion of the feedwater system that forms part of the RCPB and penetrates the primary containment has three valves. The first valve, a check valve, is classified as a containment isolation valve and located inside the primary containment. The second valve, a positive-acting check valve, is classified as a containment isolation valve and located outside the primary containment as close as possible to the primary containment penetration. Upon a loss of water flow into the RPV, these valves close as normal check valves, and, in addition, the main control room operator can assist in starting the outboard valve closure by sending a signal to open two fail-open solenoid valves arranged in parallel, releasing air pressure from the operator cylinder. If a break occurs in the feedwater line, the two containment isolation valves prevent significant loss of inventory and offer immediate isolation. During the postulated LOCA, it is desirable to maintain reactor coolant makeup from all sources of supply. For this reason, the feedwater containment isolation valves do not automatically close on a primary containment isolation signal.

A third valve in the feedwater line is a motor-operated check valve located outside primary containment, and is capable of being remotely closed from the main control room. This valve provides redundant isolation and long-term leakage protection upon operator judgment that continued makeup through the feedwater line is unavailable.

IS CLASSIFIED A CONTAINMENT ISOLATION VALVE

After observing indication of low feedwater flow, the operator may close the third valve within 20 minutes after a postulated LOCA.

CONTAINMENT ISOLATION

In addition to the third valve, there are valves on the high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) discharge lines, and on the reactor water cleanup system (RWCU) return lines that connect to the feedwater lines between the TWO outside containment isolation valves. ~~and the third valve.~~ Those valves can be closed by operator action from the main control room.

See Section 5.4.9 for a further discussion of the design of the main steam lines and the feedwater lines.

6.2.4.3.1.3 Residual Heat Removal Shutdown Cooling Suction Line

The residual heat removal (RHR) shutdown cooling suction line penetrates primary containment and taps into one of the two recirculation loops. Isolation is provided by two normally closed motor-operated gate valves that are interlocked closed by a reactor high pressure signal during normal operation and are maintained closed during an accident by a low water level isolation signal. One containment isolation valve is located inside primary containment, and the second valve is located outside primary containment.

ADDITIONALLY, THE HPCI AND/OR RCIC VALVES CAN BE OPENED FROM THE MAIN CONTROL ROOM TO PROVIDE A WATER SEAL ON THE THIRD VALVE IN ADDITION TO SUPPLYING WATER TO THE RPV. SEE SECTION 6.2.3.2.3 FOR FURTHER DETAILS.

6.2.4.3.1.8 Reactor Pressure Vessel Headspray Line

The RPV headspray line is used during the shutdown cooling mode to limit thermal stresses in the reactor head volume. Isolation for this line is provided by a normally closed, motor-operated gate valve inside containment and a normally closed, motor-operated globe valve on the outside. Both valves are interlocked closed by a reactor high pressure signal during normal operation and are maintained closed during an accident by a low water level isolation signal.

6.2.4.3.1.9 Main Steam Drain Line

The main steam drain line is isolated by two motor-operated gate valves that isolate upon a containment isolation signal.

6.2.4.3.1.10 Reactor Recirculation System Process Sample Lines

OPEN The reactor recirculation system process sample lines are isolated by two, normally ~~closed~~, solenoid-operated globe valves that isolate on a containment isolation signal.

6.2.4.3.1.11 Standby Liquid Control Line

Provided that the standby liquid control (SLC) system has not been used, the explosive-actuated valves provide the absolute seal for long-term leakage control. After system operation, isolation is provided by a check valve inside primary containment, and two, independent, motor-operated globe stop-check valves located outside primary containment on branching lines. The stop-check valves are manually closed from the main control room after system operation.

6.2.4.3.1.12 Reactor Recirculation Pump Seal Lines

The reactor recirculation pump seal lines are isolated by a check valve inside primary containment and a motor-operated globe valve outside primary containment that closes on a containment isolation signal.

the containment. Table 6.2-25 identifies those penetrations isolated with only a single isolation valve. Figures 6.2-45, 6.2-46, 6.2-47, and 6.2-48 show the limits of the extended containment boundary. All manual valves at the system boundary, vent valves, test valves, and drain valves, are ~~locked closed and~~ under administrative control to assure the integrity of the extended containment boundary. Isolation provisions for the extended containment boundaries are identified in Table 6.2-26. Table 6.2-26 also evaluates the ability of check valves and safety/relief valves to maintain the extended containment boundary. All extended containment boundaries are Quality Group B (i.e., ASME B&PV Code Class 2 piping), Seismic Category I, and designed to temperature and pressure ratings at least equal to that of the containment as identified in Figures 6.2-45 through 6.2-48.

Missile protection for plant systems and structures is discussed in Section 3.5.

6.2.4.3.5.1 Conclusion on Other Defined Bases

When greater safety is ensured by using a single primary containment isolation valve, a dependable closed system outside primary containment is provided to act as a second barrier against the release of radioactive materials.

instrumentation, and those lines containing excess flow check valves, will have their leak tightness verified during the Type A test. These instrument lines were designed on an "other defined basis" of GDC 56 (see Sections 6.2.4.3.2.21 and 6.2.4.3.5) and hence are not capable of being Type C tested. Instrument lines are provided with a manual isolation valve outside containment for greater reliability. The systems they serve are closed systems outside containment, thereby providing reliable boundaries against containment leakage. The Type A test that will be conducted on these instrument lines serves to adequately assure integrity.

6.2.4.4.3 Feedwater Isolation Valves DELETED

~~10CFR50, Appendix J, Paragraph III.C.2(b) requires valves that are sealed with fluid from a seal system to be pressurized with that fluid to a test pressure not less than 1.10 Pa. The feedwater isolation valves, consisting of three check valves of which two are outside containment, will be sealed with water from the high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems for at least 30 days following a LOCA. Leakage on the inboard and first outboard check valves will be determined from a Type C gas test conducted at Pa but will not be added to the 0.60La allowable leakage total. The design of the feedwater system includes two check valves serving as isolation valves, one inside containment and one outside containment with an air-operator, followed by another check valve outside containment with a motor-operator (see FSAR Figure 6.2-28, Sheet 2 of 48). In addition, a feedwater line fill network outside containment is used to maintain a water seal in the feedwater lines following a LOCA. The fill network consists of the HPCI and the RCIC jockey pump loops and utilizes the HPCI and RCIC injection lines to the feedwater piping to provide makeup water to the piping between the outboard check valves.~~

~~A Type C gas test will be performed at Pa on the two check valves classified as containment isolation valves, with leakage through the valves limited to 15 scf per hour. The leakage values obtained will not be included in the 0.60La allowable leakage because during the initial portion of a LOCA, water in the feedwater system piping downstream of the no. 3 feedwater heater will flash to steam. This steam will continue to flow toward the reactor pressure vessel until pressure in the feedwater line decreases to the containment pressure, at which time the isolation valves will be closed manually. In addition, a water seal will be maintained upstream of the third feedwater heater since the maximum water temperature is 221.9ºF and the feedwater is in a no flow condition. These conditions prevent the outward~~

9 ~~leakage of radioactive contaminants through the isolation valves during approximately a 1-hour period after the accident, i.e., until the water seal is reestablished; thus, no bypass leakage of the feedwater system is expected to occur.~~

9 ~~A Type C water test will be performed at 1.10Pa on the outermost check valve and its leakage included with all other hydrostatically tested valves. Once the water seal system is activated, any external leakage would be through this boundary valve via the seal fluid. The Type C water test will be sufficient to assure proper leakage verification. Also see Sections 5.4.9, 6.2.3.2.3, and 6.2.4.3.1.2.~~

6.2.4.4.4 Main Steam Isolation Valves

10CFR50, Appendix J, Paragraph III.C.2(b) requires valves that are sealed with fluid from a system to be pressurized with that fluid to a test pressure not less than 1.10Pa. The main steam isolation valves (MSIVs) will be leakrate tested by pressurizing between the inboard and outboard MSIVs and between the outboard MSIV and the main steam stop valve (MSSV) at a reduced pressure of 5 psig. The main steam isolation valve sealing system (MSIVSS) (see Section 6.7) is initiated manually approximately 20 minutes after the onset of a LOCA and only after main steam line pressure is below 20 psig. This latter restriction is necessary since the MSIVSS maintains the pressure between the valves at reactor vessel pressure plus 5 psig and because a back pressure differential of 25 psi will lift the MSIV disk, unseating the valve. Therefore, testing of the two MSIVs simultaneously, between the valves, at 1.10Pa would lift the disk at the inboard valve and result in a meaningless test. A test will be conducted at 5 psig (the seal system differential pressure) with the total observed leakage through both the outboard MSIV and the MSSV conservatively assigned to that penetration and limited to 11.5 scf per hour for any one main steam line.

6.2.4.4.5 Containment Air Locks

10CFR50, Appendix J, Paragraph III.D.2(b)(ii) requires air locks that have been used during periods when containment integrity is not required by the plant's Technical Specifications to be tested at the end of such periods at not less than Pa. In addition to the 6-month intervals, air locks will be subjected to an overall air lock leakage integrity test only when maintenance on the air lock has been performed that could affect the air lock's sealing capability. This is an exemption to Paragraph III.D.2(b)(ii)

All valves that are exposed to the primary containment atmosphere after a DBA are tested with air or nitrogen at primary containment peak accident pressure, P_a, as defined in Table 6.2-22.

All valves in lines designed to be filled with a liquid for a minimum of 30 days after a DBA are leakage-rate-tested with the same liquid at a minimum pressure of P_a.

Liquid leakage is not converted to equivalent air leakage, or added to the Type C testing total, but is reported separately as "liquid leakage" and included in the Technical Specifications. All the valves tested with liquid are identified in Table 6.2-24.

INSERT

The Total Allowable Leakage acceptance criteria for penetrations and isolation valves subject to Type B and C tests are given in Chapter 16.

6.2.6.4 Scheduling and Reporting of Periodic Tests

The periodic leakage rate test schedules for Type A, B, and C testing are given in Chapter 16.

Type B and C tests are performed prior to initial criticality and periodically thereafter, during shutdown periods or normal plant operations.

The preoperational Type A test follows the preoperational ASME Section III pressure test. A primary containment isolation system functional test and Type B and C leakage tests are completed prior to the preoperational Type A test.

The procedure for reporting test results is given in Chapter 16.

INSERT FOR PAGE 6.2-94

Containment isolation of the feedwater lines represents a unique situation which requires a combination of air and water testing and therefore merits further discussion. During the short-term feedwater system line-up, isolation of the feedwater lines is provided by valves AE-V002, AE-V003, AE-V006 and AE-V007 and the water seal upstream of the third feedwater heaters (see Section 6.2.3.2.3). Hence, a Type C test will be performed on these valves with their leakage appropriately included in the 0.60 La criteria. During the long-term feedwater system line-up, isolation of the feedwater lines is provided by a water seal on the third feedwater check valves, AE-V001, and AE-V005. Identification of these valves as containment isolation valves requires a similar classification for the first valve in each branch line between the second and third feedwater check valves, BD-V005, BJ-V059, and AE-V021. Since the leakage past these valves will be into the RCIC, HPCI and RWCU systems, respectively, which are seismically qualified, water-filled, closed systems outside containment, there is no requirement to identify their specific leakage in the Technical Specifications. However, leakage through the valves which form the long-term seal boundary of the feedwater lines (i.e., AE-V001, AE-V005, AE-V021, BD-V005 and BJ-V059) will be determined by a Type C water test and will be limited to 10 gpm as specified in the Technical Specifications. Since these valves are sealed with water, the leakage determined from their Type C test need not be included in the 0.60 La criteria per 10CFR50 Appendix J Paragraph III.C.3.

TABLE 6.2

CONTAINMENT PEN

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test
PROCESS LINE PENETRATIONS										
P-1A	Main Steam	Steam/ Water	26	55	No	AB-V028	GB	Inside	1/A	No
			26			AB-V032	GB	Outside		No
			2			AB-V059	GB	Outside		No
			2			KP-V010	GB	Outside		No
P-1B	Main Steam	Steam/ Water	26	55	No	AB-V029	GB	Inside	1/A	No
			26			AB-V033	GB	Outside		No
			2			AB-V060	GB	Outside		No
			2			KP-V009	GB	Outside		No
P-1C	Main Steam	Steam/ Water	26	55	No	AB-V030	GB	Inside	1/A	No
			26			AB-V034	GB	Outside		No
			2			AB-V061	GB	Outside		No
			2			KP-V008	GB	Outside		No
P-1D	Main Steam	Steam/ Water	26	55	No	AB-V031	GB	Inside	1/A	No
			26			AB-V035	GB	Outside		No
			2			AB-V062	GB	Outside		No
			2			KP-V007	GB	Outside		No
P-2A	Feedwater	Water	24	55	No	AE-V003	CK	Inside	2/B	Yes (19
			24			AE-V002	CK	Outside		Yes (19
P-2B	Feedwater	Water	24	55	No	AE-V007	CK	Inside	2/B	Yes (19
			24			AE-V006	CK	Outside		Yes (19
P-3	RHR Shutdown Cooling Suction	Water	20	55	Yes	BC-V071	GT	Inside	3/C	Yes
			1			BC-PSV-4425	PSV	Inside		Yes
			20			BC-V164	GT	Outside		Yes
P-4A	RHR Shutdown Cooling Return	Water	12	55	Yes	BC-V014	CK	Inside	4/D	Yes
			1			BC-V118	GB	Inside		Yes
			12			BC-V013	GB	Outside		Yes
P-4B	RHR Shutdown Cooling Return	Water	12	55	Yes	BC-V111	CK	Inside	4/D	Yes
			1			BC-V117	GB	Inside		Yes
			12			BC-V110	GB	Outside		Yes

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			4			AE-V021	CK	OUTSIDE		YES (22
			6			BD-V005	GT	OUTSIDE		YES (22
			24			AE-V001	CK	OUTSIDE		YES (22
			4			AE-V021	CK	OUTSIDE		YES (22
			8			BJ-V059	GT	OUTSIDE		YES (22
			24			AE-V005	CK	OUTSIDE		YES (22

Length of Pipe from Cont. to Outside Valves, ft.	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
-	Instr. gas	Manual	O	C	C	C	B,D,E,F,G,K	5	*	a,t,y,cc
3.8	Compr. air	Manual	O	C	C	C	B,D,E,F,G,K	5	Z	a,t,y,cc
9.4	AC motor	Manual	O	C	C	AS IS	B,D,E,F,G,K	45	D	t,y,cc
16.5	AC motor	Manual	C	O	C	AS IS	A,H,I	45	D	t,x,y,cc
-	Instr. gas	Manual	O	C	C	C	B,D,E,F,G,K	5	*	a,t,y,cc
3.8	Compr. air	Manual	O	C	C	C	B,D,E,F,G,K	5	Z	a,t,y,cc
9.4	AC motor	Manual	O	C	C	AS IS	B,D,E,F,G,K	45	D	t,y,cc
14.1	AC motor	Manual	C	O	C	AS IS	A,H,I	45	D	t,x,y,cc
-	Instr. gas	Manual	O	C	C	C	B,D,E,F,G,K	5	*	a,t,y,cc
3.8	Compr. air	Manual	O	C	C	C	B,D,E,F,G,K	5	Z	a,t,y,cc
9.4	AC motor	Manual	O	C	C	AS IS	B,D,E,F,G,K	45	D	t,y,cc
16.4	AC motor	Manual	C	O	C	AS IS	A,H,I	45	D	t,x,y,cc
-	Instr. gas	Manual	O	C	C	C	B,D,E,F,G,K	5	*	a,t,y,cc
3.8	Compr. air	Manual	O	C	C	C	B,D,E,F,G,K	5	Z	a,t,y,cc
9.4	AC motor	Manual	O	C	C	AS IS	B,D,E,F,G,K	45	D	t,y,cc
14.9	AC motor	Manual	C	O	C	AS IS	A,H,I	45	D	t,x,y,cc
-	Flow	None	O	C	C	NA	-	NA	NA	s
4.5	Flow	Manual (17)	O	C	C	C	None	NA	N	s
0.5	Flow	None	O	C	C	NA	-	NA	NA	s
4.5	Flow	Manual (17)	O	C	C	C	None	NA	N	s
-	AC motor	Manual	C	O	C	AS IS	J	45	A	b,s
-	Spring	None	C	C	C	NA	-	NA	NA	s,z
0.5	AC motor	Manual	C	O	C	AS IS	J	45	D	b,s
-	Flow	None(16)	C	O	C	NA	-	NA	NA	s
-	Spring	Manual	C	C	C	C	None	NA	B	t
0.0	AC motor	Manual	C	O	C	AS IS	J	45	D	s
-	Flow	None(16)	C	O	C	NA	-	NA	NA	s
-	Spring	Manual	C	C	C	C	None	NA	A	t
0.0	AC Motor	Manual	C	O	C	AS IS	J	45	D	s
34.0	FLOW	MANUAL (13)	O	C	C	C	NONE	NA	D	t
33.3	DC MOTOR	MANUAL	C	C	O	AS IS	NONE	NA	B	S
40.12	FLOW	MANUAL (13)	O	C	C	C	NONE	NA	B	S
34.0	FLOW	MANUAL (13)	O	C	C	C	NONE	NA	D	t
31.5	DC MOTOR	MANUAL	C	C	O	AS IS	NONE	NA	A	S
40.1	FLOW	MANUAL (13)	O	C	C	C	NONE	NA	A	S

FOR INFORMATION ONLY

TABLE 6.2-

CONTAINMENT PEN

Containment Penetration Number	Line Isolated	Fluid	Line Size, in.	NRC General Design Criterion	ESF System(11)	Valve Number and/or Orifice Plate	Valve Type(1)	Valve Location	Valve Arrangement(2) P&ID(8)	Type C Test
P-11	RCIC Turbine Steam Supply	Steam	4	55	No	FC-V001	GT	Inside	6/I	Yes
			4			FC-V002	GT	Outside		Yes
			1			FC-V048	GB	Inside		Yes
P-12	Main Steam Drain	Steam/ Water	3	55	No	AB-V039	GT	Inside	9/J	Yes
			3			AB-V040	GT	Outside		Yes
P-13	Spare									
P-14	Not used									
P-15	Spare									
P-16	Spare									
P-17	Reactor Recirc Water Sample	Water	3/4	55	No	BB-SV 4310	GB	Inside	10/K	Yes
			3/4			BB-SV 4311	GB	Outside		Yes
P-18	Standby Liquid Control	Sodium pen-taborated solution	1 1/2	55	Yes	BH-V029	CK	Inside	11/L	Yes
			1 1/2			BH-V028	SCK	Outside		Yes
			1 1/2			BH-V054	SCK	Outside		Yes
P-19	Recirc Pump Seal Water	Water	3/4	55	No	BB-V043	CK	Inside	12/K	Yes
			3/4			BF-V098	GB	Outside		
P-20	Recirc Pump Seal Water	Water	3/4	55	No	BB-V047	CK	Inside	12/K	Yes
			3/4			BF-V099	GB	Outside		
P-21	ISI Access Penetration									
P-22	Drywell Purge Inlet Vent	Gas	26	56	Yes	GS-V009	BF	Outside	13/M	Yes
			6			GS-V023	BF	Outside		Yes
			26			GS-V021	BF	Outside		Yes
			24			GS-V020	BF	Outside		Yes
			4			GS-V004	GT	Outside		Yes
			4			GS-V005	GT	Outside		Yes
P-23	Drywell Purge Outlet Vent	Gas	26	56	Yes	GS-V024	BF	Outside	14/M	Yes
			26			GS-V026	BF	Outside		Yes
			2			GS-V025	GB	Outside		Yes
			4			GS-V002	GT	Outside		Yes
			4			GS-V003	GT	Outside		Yes
P-24A	RHR Contain-ment Spray	Water	16	56	Yes	BC-V019	GT	Outside	15/D	Yes
			16			BC-V018	GT	Outside		Yes

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ength of ipe from ont. to utside alves, ft.	Primary Mode of Operation(3)	Secondary Method of Actuation(12)	Normal Valve Position(4)	Shutdown Valve Position(10)	Post-Accident Position(9)	Power Failure Valve Position	Containment Isolation Signal(5)	Valve Closure Time, S	Power Source(6)	Remarks(7)
-	AC motor	Manual	O	C	O	AS IS	None	NA	D	a,s
1.0	AC motor	Manual	O	C	O	AS IS	None	NA	B	a,s
-	AC motor	Manual	C	C	C	AS IS	None	NA	D	a,t
-	AC motor	Manual	O	C	C	AS IS	B,D,E,F,G,K	30	A	t
0.5	AC motor	Manual	O	C	C	AS IS	B,D,E,F,G,K	30	D	t
										m
										m
										m
-	Spring	Manual	O	C	C	C	A,B	15	A	t
12.2	Spring	Manual	O	C	C	C	A,B	15	D	t
-	Flow	None	C	C	C	NA	-	NA	NA	s
12.6	Flow	Manual (13)	O	O	O	C	None	NA	A	s
10.6	Flow	Manual (13)	O	O	O	C	None	NA	D	s
-	Flow	None	O	C	C	NA	-	NA	NA	t
15.8	AC motor	Manual	O	C	C	AS IS	H,K	45	D	t
-	Flow	None	O	C	C	NA	-	NA	NA	t
23.7	AC motor	Manual	O	C	C	AS IS	H,K	45	D	t
										m
-	Spring	Manual	C	C	C	C	A,H,I	15	A	t,v,x
43.6	Spring	Manual	C	C	C	C	A,H,I	15	D	t,x
43.6	Spring	Manual	C	C	C	C	A,H,I	15	D	t,x
42	Spring	Manual	C	C	C	C	A,H,I	15	D	t,x
-	AC motor	Manual	C	O	C	AS IS	A,H,I	45	B	s,x
10.7	AC motor	Manual	C	O	C	AS IS	A,H,I	45	D	s,x
-	Spring	Manual	C	C	C	C	A,H,I	15	A	t,x
5.3	Spring	Manual	C	C	C	C	A,H,I	15	D	t,x
25.7	Spring	Manual	C	C	C	C	A,H,I	15	D	t,x
-	AC motor	Manual	C	O	C	AS IS	A,H,I	45	A	s,x
7.4	AC motor	Manual	C	O	C	AS IS	A,H,I	45	C	s,x
-	AC motor	Manual	C	O	C	AS IS	None	NA	B	s
6.0	AC motor	Manual	C	O	C	AS IS	None	NA	B	s

TABLE 6.2-16 (Cont'd)

(9) Post-Accident valve position (open or closed) is the position during the initial 10 minutes after an accident.

(10) Shutdown valve position (open or closed) is the position beyond the initial 10 minutes after an accident.

(11) The ESF System designation is applied to primary containment penetrations that are a part of an ESF System and where that part of the system provides or aids a function that is characteristic of an ESF System. Although reactivity control systems are not usually characterized as being ESF Systems, in this table reactivity control system penetrations are given the ESF system designation.

(12) Manual indicates remote manual initiation of valve closure from the main control room.

(13) The secondary mode of operation is AC motor.

(14) Operation is by local manual hand wheel.

(15) Deleted

(16) The valve actuator is only used to exercise the valve disk during testing.

(17) This is a spring loaded piston-actuated check valve. When the valve operator is in the open position, it will not resist valve closure. In this position the valve will function much like a simple check valve. In the de-energized position, the spring-loaded piston will assist in closing the valve. However, it will not close the valve against flow from the normal direction.

(18) The isolation signals for his valve are generated to provide proper system alignment for ECCS injection. By assuming the ECCS injection position, the valves also provide a containment isolation function.

(19) THESE VALVES ARE TESTED WITH AIR TO A PRESSURE OF Pa AND THE LEAKAGE IS INCLUDED IN THE 0.60La CRITERIA OF APPENDIX J.

(20) THESE VALVES FORM THE BOUNDARY FOR THE LONG-TERM SEAL OF THE FEEDWATER LINES AND HENCE ARE TESTED WITH WATER AT 1.10Pa. LEAKAGE FROM ALL VALVES IS LIMITED TO 10 GPM.

CONTAINMENT PENETRATIONS/ISOLATION VALVE COMPLIANCE WITH 10 CFR 50, APPENDIX J

Penet Number	P&ID Number	System Description	Test Type	Inboard Isolation Barrier Description/ Valve Number	Notes	Outboard Isolation Barrier Description/ Valve Number	Notes
P 1A	M-41	Main steam line A	-	AB V028	6	AB-V032, AB-V059, KP-V010	6
P 1B	M-41	Main steam line B	-	AB V029	6	AB-V033, AB-V060 KP-V009	6
P 1C	M-41	Main steam line C	-	AB V030	6	AB-V034, AB-V061, KP-V008	6
P 1D	M-41	Main steam line D	-	AB-V031	6	AB-V035, AB-V062 KP-V007	6
P 2A	M-41	Feedwater	C	AE-V003	-	AE-V002, AE-V001 AE-V021, BD-V005	-
P 2B	M-41	Feedwater	C	AE-V007	-	AE-V006, AE-V005 AE-V021, BJ-V059	-
P 3	M-51	RHR shutdown cooling suction	C A,C	BC-V071 BC-PSV-4425	- 7,17	BC-V164	14
P 4A	M-51	RHR shutdown cooling return	C C	BC-V014 BC-V118	- -	BC-V013	-
P 4B	M-51	RHR shutdown cooling return	C C	BC-V111 BC-V117	- -	BC-V110	-
P 5A	M-52	Core spray to reactor	C C	BE-V002 BE-V072	- -	BE-V003	-
P 5B	M-52	Core spray to reactor	C C	BE-V006 BE-V071	- -	BE-V007 BJ-V001	- -
P 6A	M-51	LPCI	C	BC-V005, BC-V122	-	BC-V004	-
P 6B		LPCI	C	BC-V017, BC-V120	-	BC-V016	-
P 6C		LPCI	C	BC-V114, BC-V119	-	BC-V113	-
P 6D		LPCI	C	BC-V102, BC-V121	-	BC-V101	-
P 7	M-55	HPCI turbine steam supply	C	FD-V001 FD-V051	8 -	FD-V002	8

TABLE 6.2-26 (cont) Page 2 of 3

Line Isolated	Valve[4] Number	Operator Number	Essential/ Non-Essential	Isolation Signals[2]	Comments [3]
Station Service Water	BC-V039	HV-F075	Non-Essential	None	E
--	FD-V032	None	--	--	F
--	BD-V023	None	--	--	F
--	BD-PSV-F017	None	--	--	G
--	BJ-PSV-F020	None	--	--	G

INSERT

NOTES:

[1] Where a single containment isolation valve is used, HCGS takes credit for the connecting system being a closed system outside primary containment (as defined in Regulatory Guide 1.141). In the case of a single failure, the closed system accommodates the failure by being an extension of the containment. The intersystem valves assure the integrity of the extended containment boundary. These valves meet all the requirements of primary containment isolation valves including the NUREG-0737, Item II.E.4.2 requirements.

[2] Table of Isolation Signal Codes

A - Reactor Vessel Low Water Level - Level 2
B - Drywell High Pressure
C - Reactor Building High Radiation
D - Reactor Vessel Low Water Level - Level 3

[3] Comments

A. Using two intersystem isolation valves is conservative. If there is a single failure, and the containment isolation valve is unable to close, HCGS assumes credit for the closed system outside primary containment to accommodate the failure: Only one intersystem isolation valve in conjunction with the containment isolation valve is required to assure that the integrity of the closed system serving as an extension of the primary containment is maintained. If the single failure is loss of the intersystem isolation valves, the containment isolation valve will still be functional. Hence, the closed system would not constitute an extension of the primary containment and a second intersystem valve would not be required.

B. The post-accident sampling system is a fail-safe system, and will isolate on loss of power. The system meets the requirement of a sealed closed system. Power to open the system is provided only under administrative control.

INSERT FOR TABLE 6.2-26 PAGE 2 OF 3

--	BC-PSV-F029	None	--	--	H
--	BC-PSV-F030A	None	--	--	H
--	BC-PSV-F030B	None	--	--	H
--	BC-PSV-F030C	None	--	--	H
--	BC-PSV-F030D	None	--	--	H

TABLE 6.2-26 (cont) Page 3 of 3

C. Although the system is classified as non-essential, if the system is functional, it will be necessary to open the containment isolation valves after an accident, in order for the system to perform its intended function.

D. Deleted.

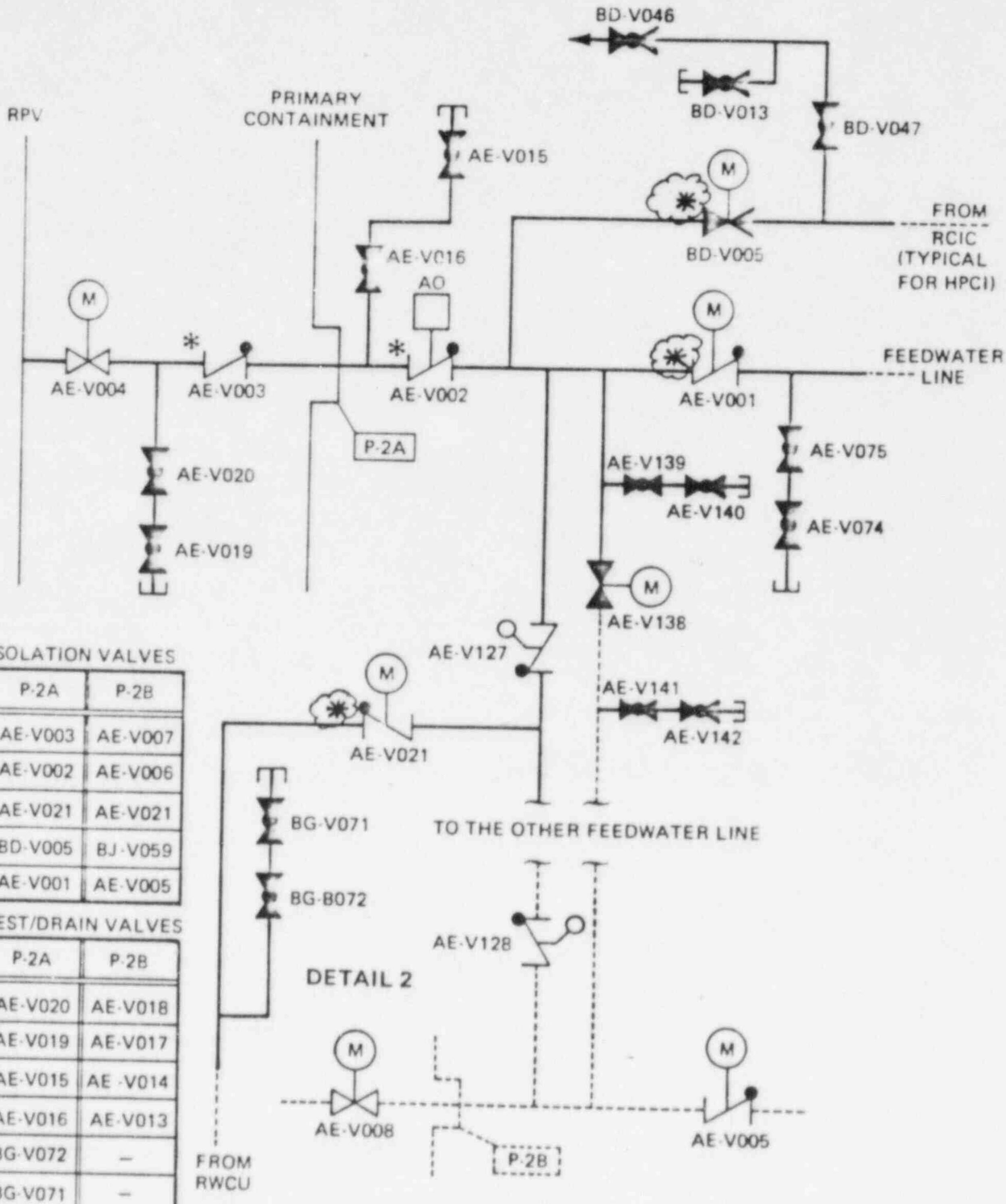
E. The valve is seal closed.

F. Use of a check valve as a system isolation valve is acceptable because it is located below the suppression pool and will be maintained closed in the reverse flow direction by the hydrostatic pressure in the suppression pool.

G. Use of a relief valve in the forward flow direction as an isolation valve is acceptable because its set pressure is greater than 1.5 times the containment pressure. The set pressure is 100 psig.

(4) Drain valves, vent valves, and manual valves under administrative control have not been identified in this table for simplicity. However, they are identified in Figures 6.2-45, 6.2-46, 6.2-47, and 6.2-48.

H. USE OF A RELIEF VALVE IN THE FORWARD FLOW DIRECTION AS AN ISOLATION VALVE IS ACCEPTABLE BECAUSE ITS SET PRESSURE IS GREATER THAN 1.5 TIMES THE CONTAINMENT PRESSURE. THE SET PRESSURE IS 170 PSIG.



ISOLATION VALVES

P-2A	P-2B
AE-V003	AE-V007
AE-V002	AE-V006
AE-V021	AE-V021
BD-V005	BJ-V059
AE-V001	AE-V005

TEST/DRAIN VALVES

P-2A	P-2B
AE-V020	AE-V018
AE-V019	AE-V017
AE-V015	AE -V014
AE-V016	AE-V013
BG-V072	–
BG-V071	–
AE-V075	–
AE-V074	–
BD-V047	BJ-V018
BD-V046	BJ-V017
AE-V004	AE-V008
AE-V127	AE-V128

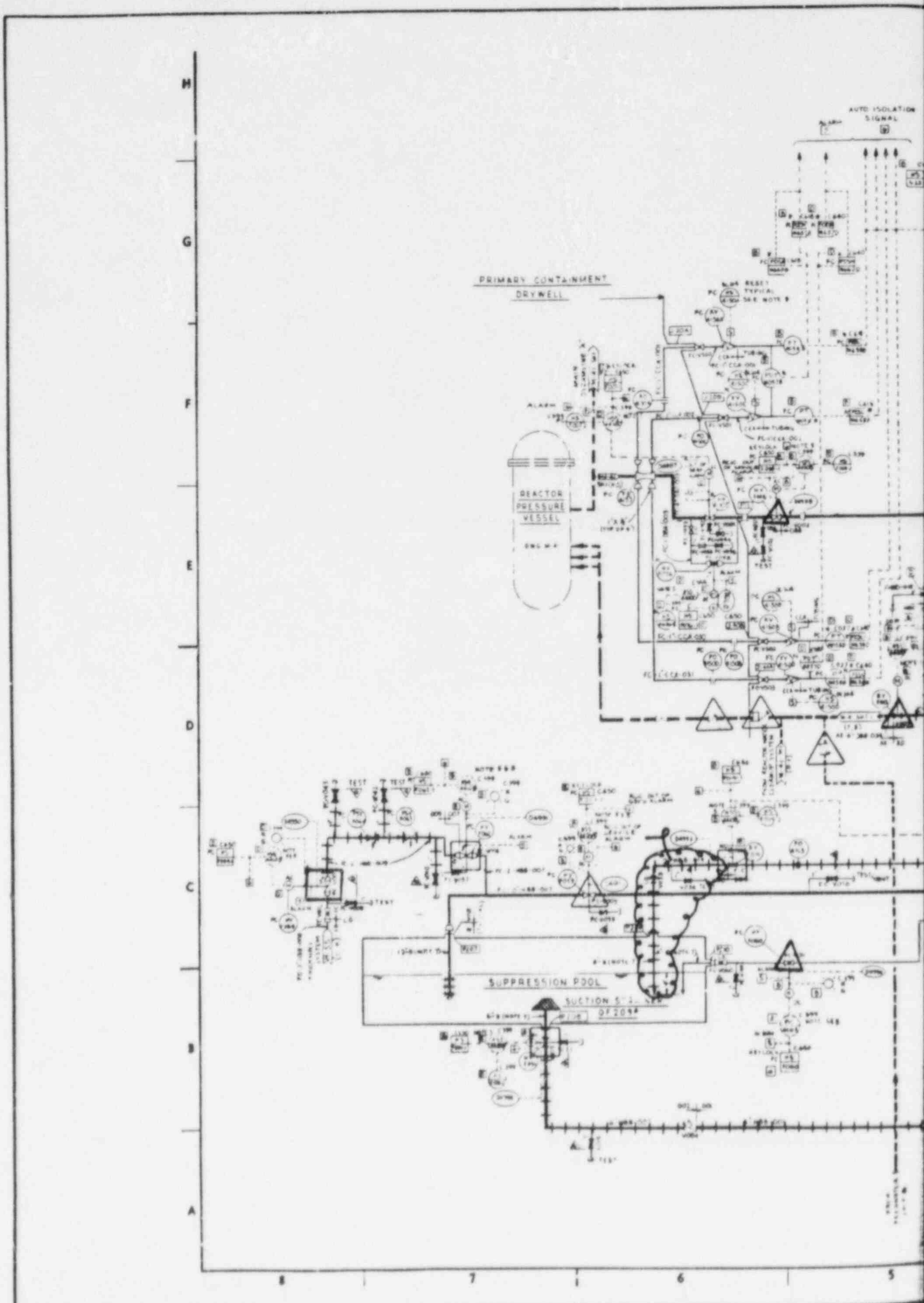
* (SEE LEGEND)

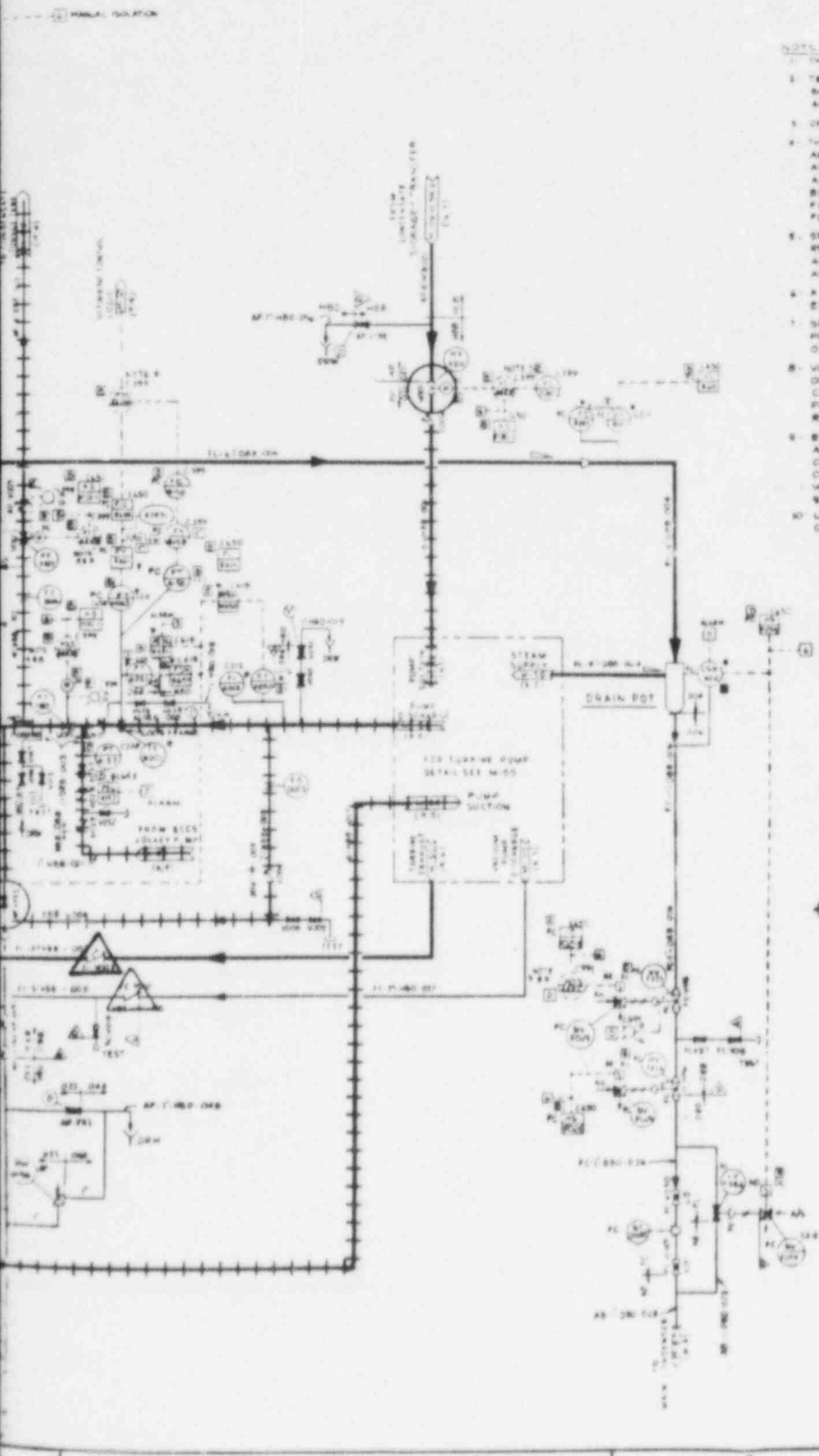
HOPE CREEK
GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

FEEDWATER LINES

FIGURE 6.2-28
SHEET 2 OF 48

Amendment 14, 01/86


AUTO ISOLATION SIGNAL
ALARM
PRIMARY CONTAINMENT
DRYWELL
REACTOR
PRESSURE
VESSEL
TEST
SUPPRESSION POOL
H
G
F
E
D
C
B
A
8
7
6
5



NOTES:
1. THE OF HPL NUMBER FOR THIS SYSTEM IS 8-9.
2. TEMPERATURE LEAK DETECTION FOR THIS SYSTEM IS SHOWN ON R&S A. THE TEMPERATURE INSTRUMENTS ARE INDEXED AS PART OF THIS P&ID (M-49).
3. DELETED.
4. THIS P&ID CONTAINS SYSTEMS OR PORTIONS OF SYSTEMS:
   AB - MAIN STEAM
   AE - FEEDWATER
   AP - CONDENSATE STORAGE AND TRANSFER
   BD - REACTOR CORE ISOLATION COOLING
   FC - RCIC TURBINE STEAM
   FD - HPCI TURBINE STEAM
5. SELECTOR SWITCHES HSS-4410B AND HSS-4410D ARE RSP CHANNEL TRANSFER SWITCHES. THESE SWITCHES ARE SHOWN MORE THAN ONCE ON THIS P&ID AND ARE ALSO SHOWN ON OTHER P&ID'S.
6. A SUMMARY ALARM IS USED BY ALL OF THE ECCS FLOODING ALARMS. SEE REF. 4 AND 5.
7. SEE CIVIL DRAWING 10855-C-0951(Q) FOR THE PRESSURE RATING, MATERIAL AND CODE CLASS OF THE PIPING INSIDE SUPPRESSION POOL.
8. VALVES HV-F012, F089, F060, F061 AND F084 OPEN ON TRANSFER AND HV-F026 AND F011 CLOSE ON TRANSFER TO REMOTE SHUTDOWN PANEL. STATUS INDICATION IS PROVIDED ON RSP BUT NO CONTROL.
9. EXCESS FLOW CHECK VALVES STATUS LIGHTS AND RESET SWITCHES ARE LOCATED ON REMOTE CONTROL PANELS AS NOTED. ALARMS AND COMPUTER READOUTS FOR ABNORMAL CONDITIONS WILL BE MONITORED FROM THE CONTROL ROOM. SEE REF. 7.
10. LEVEL SWITCHES 1BD-LIS-N086 A,C,E ARE SHOWN ON CONDENSATE STORAGE TANK (10855-M-08(Q)).

□ ISOLATION VALVE FOR PENETRATION WITH ONLY ONE ISOLATION VALVE

△ ISOLATION VALVE FOR PENETRATION WITH REDUNDANT ISOLATION VALVES

○ SYSTEM ISOLATION VALVES ASSOCIATED WITH PRIMARY CONTAINMENT ISOLATION

++++ INDICATES THE EXTENDED CONTAINMENT BOUNDARY AFTER SINGLE FAILURE

THIS FIGURE IS BASED ON M-49-1 BUT HAS BEEN FROZEN AT REV. 10.

~~M-49-1, REV. 10~~

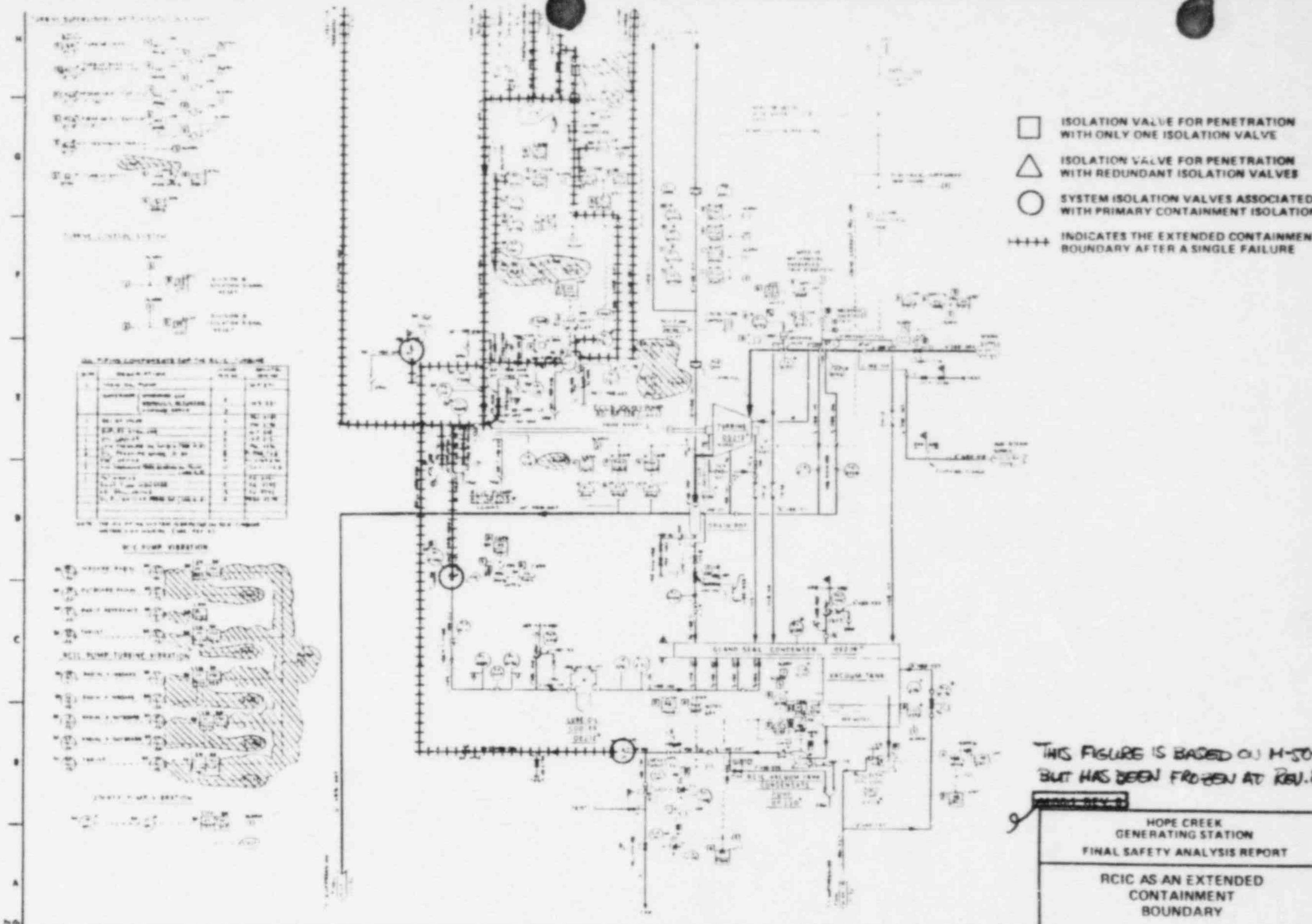
HOPE CREEK
GENERATING STATION

FINAL SAFETY ANALYSIS REPORT

RCIC AS AN EXTENDED
CONTAINMENT BOUNDARY

FIGURE 6.2-45
SHEET 1 OF 2

Amendment 13, 1/85

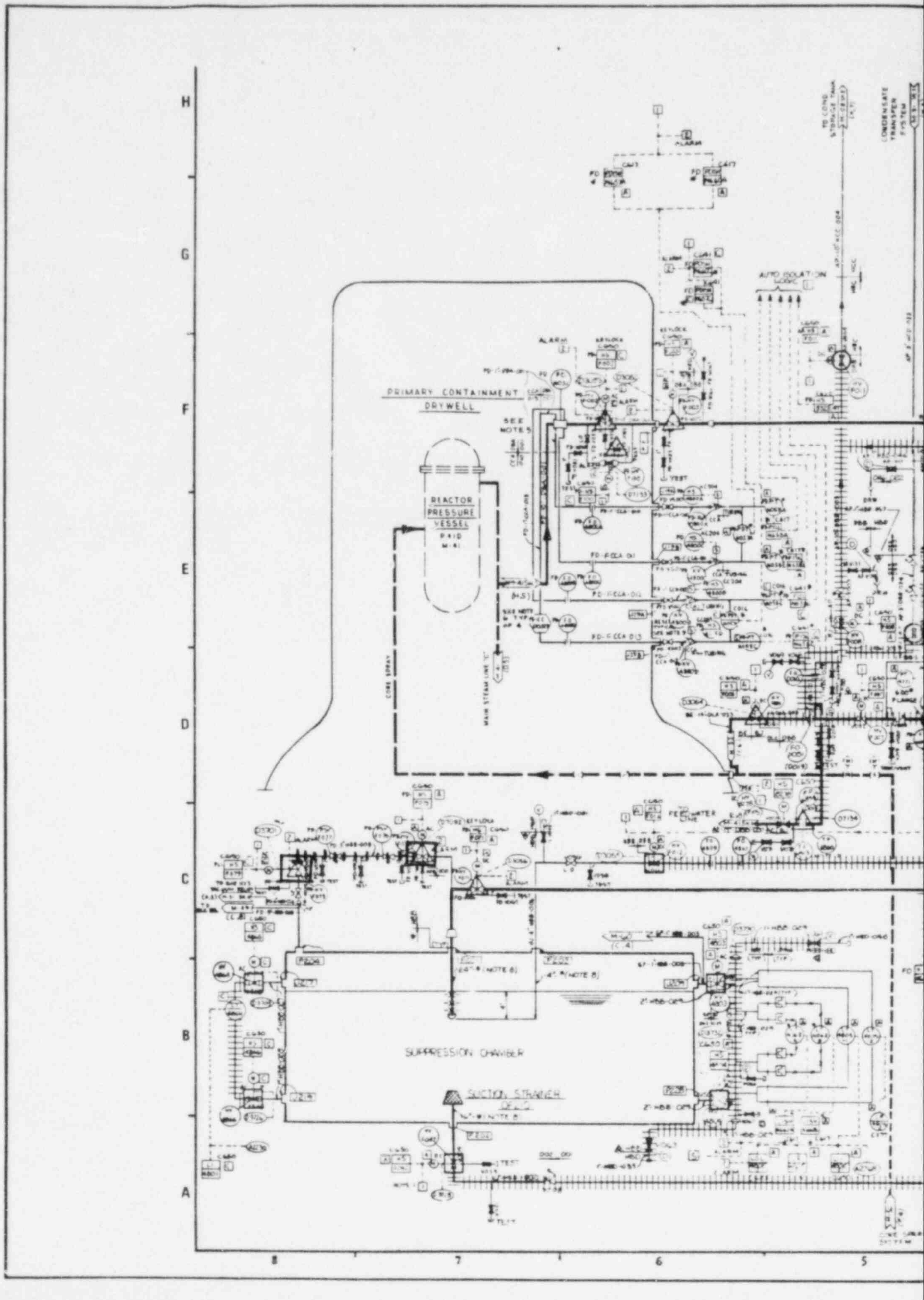


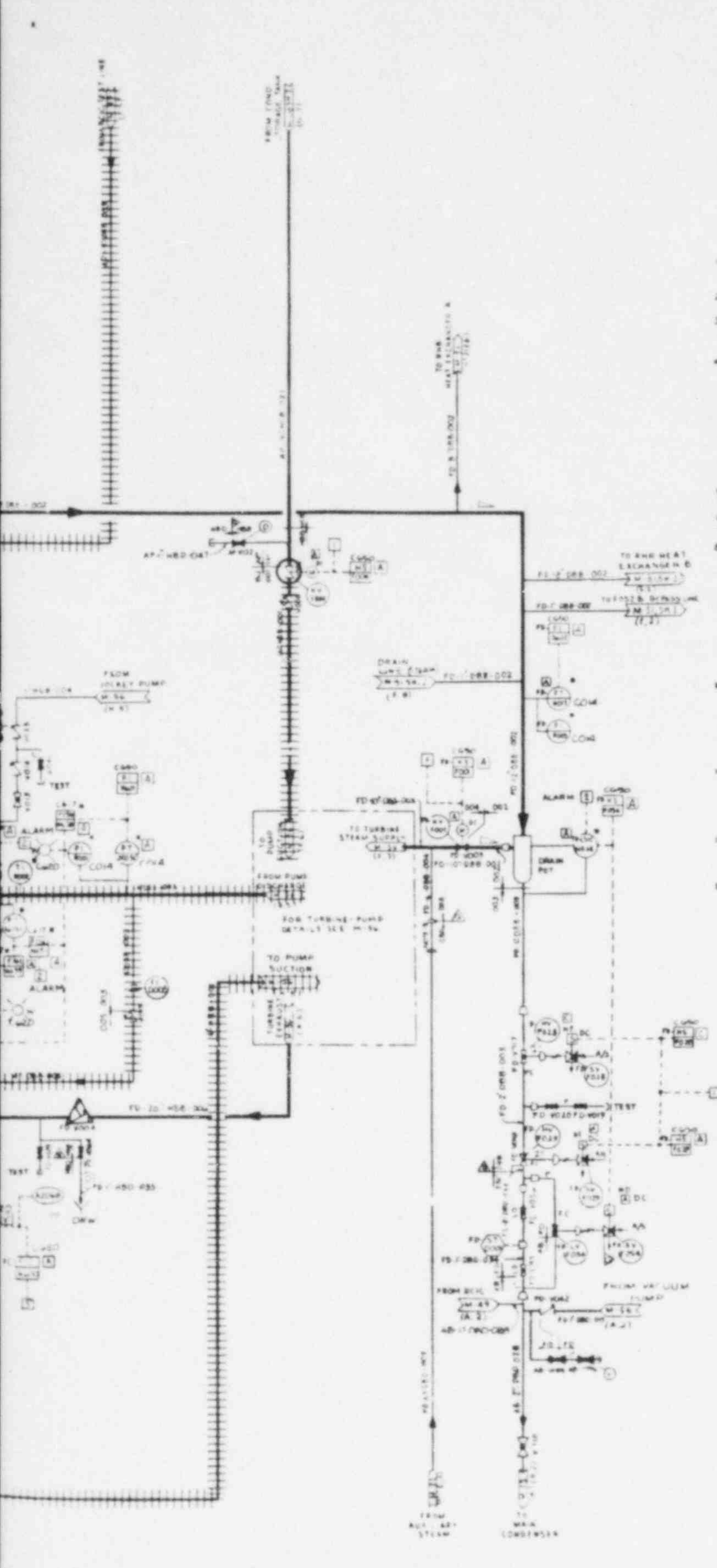
HOPE CREEK
GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

RCIC AS AN EXTENDED CONTAINMENT BOUNDARY

FIGURE 6.2-46
SHEET 2 OF 2

Amendment 2, 10/83


H
G
F
E
D
C
B
A
8
7
6
5
PRIMARY CONTAINMENT
DRYWELL
SEE NOTE 5
REACTOR PRESSURE VESSEL
AUTO ISOLATION LOGIC
CONDENSATE TRANSFER SYSTEM
ALARM
FEEDWATER LINE
SUPPRESSION CHAMBER
SUCTION STRAINER
CORE SPRAY
MAIN STEAM LINE "C"
TEST



1. LEVEL TRANSMITTERS LT N061A & 61B ARE SHOWN ON CONDENSATE STORAGE TANK P&ID (10855-M-08-0)
2. THE GE MPL NUMBER FOR THIS SYSTEM IS E-41
3. TEMPERATURE LEAK DETECTION FOR THIS SYSTEM IS SHOWN ON PLANT LEAK DETECTION P&ID (SEE 10855-M-25)
4. THIS P&ID CONTAINS SYSTEMS OR PORTIONS OF SYSTEMS:
   - AD- CONDENSATE
   - AP- CONDENSATE STORAGE & TRANSFER
   - BF- CONTROL ROD DRIVE HYDRAULIC SUPPLY
   - BJ- HIGH PRESSURE COOLANT INJECTION
   - FD- HPCI TURBINE STEAM
   - AB- MAIN STEAM
   - AE- FEEDWATER
   - BE- CORE SPRAY
   - GP- PRIMARY CONTAINMENT LEAKAGE RATE TESTING
5. DETAILS OF TAPS ARE SHOWN ON VENDOR DRAWINGS, ISOMETRICS, AND INSTALLATION DETAILS.
6. LINES FD-1"-CCA-(010 THRU 013) HAVE CONDENSING CHAMBERS.
7. DELETED
8. SEE CIVIL DRAWING 10855-C-0931-0 (2) FOR THE PRESSURE RATING MATERIAL & CODE CLASS OF PIPING INSIDE THE SUPPRESSION CHAMBER.
9. EXCESS FLOW CHECK VALVE STATUS LIGHTS AND RESET SWITCHES ARE LOCATED ON PANELS AS NOTED. ALARMS AND COMPUTER READOUTS FOR ABNORMAL CONDITIONS WILL BE MONITORED FROM THE CONTROL ROOM. SEE REF 4.
10. THE CONTENTS OF DCN #1 TO REVISION 1 OF THIS DOCUMENT WERE INCORPORATED INTO REVISION 2 IN CONJUNCTION WITH RELATED CHANGES TO SUPPRESSION CHAMBER LEVEL INSTRUMENTATION AS NOTED IN ITEM 4 OF THE LIST OF REVISIONS. REVISION 3 TO THIS DOCUMENT IS INITIATED TO FORMALLY DOCUMENT INCORPORATION OF THE CHANGE FOR ADMINISTRATIVE PURPOSES.
11. TAPS FOR FE N813 ARE TO BE PROVIDED FOR VERIFICATION OF HPCI FLOW SPLIT DURING STARTUP. STARTUP INSTRUMENTATION WILL BE REQUIRED TO VERIFY FLOW OF 5600 GPM ± 4%.
12. DELETED
13. AFTER TESTING, REMOVE THE SPOOL PIECE AND INSTALL BLIND FLANGES. (2,3)

□ ISOLATION VALVE FOR PROCESS PENETRATION WITH ONLY ONE ISOLATION VALVE

△ ISOLATION VALVE FOR PROCESS PENETRATION WITH REDUNDANT ISOLATION VALVES

○ SYSTEM ISOLATION VALVES ASSOCIATED WITH PRIMARY CONTAINMENT ISOLATION

INDICATES THE EXTENDED CONTAINMENT BOUNDARY AFTER A SINGLE FAILURE

THIS FIGURE IS BASED ON M-55-1 BUT HAS BEEN FROZEN AT REV. 15.

~~M-55-1, REV 15~~

HOPE CREEK GENERATING STATION

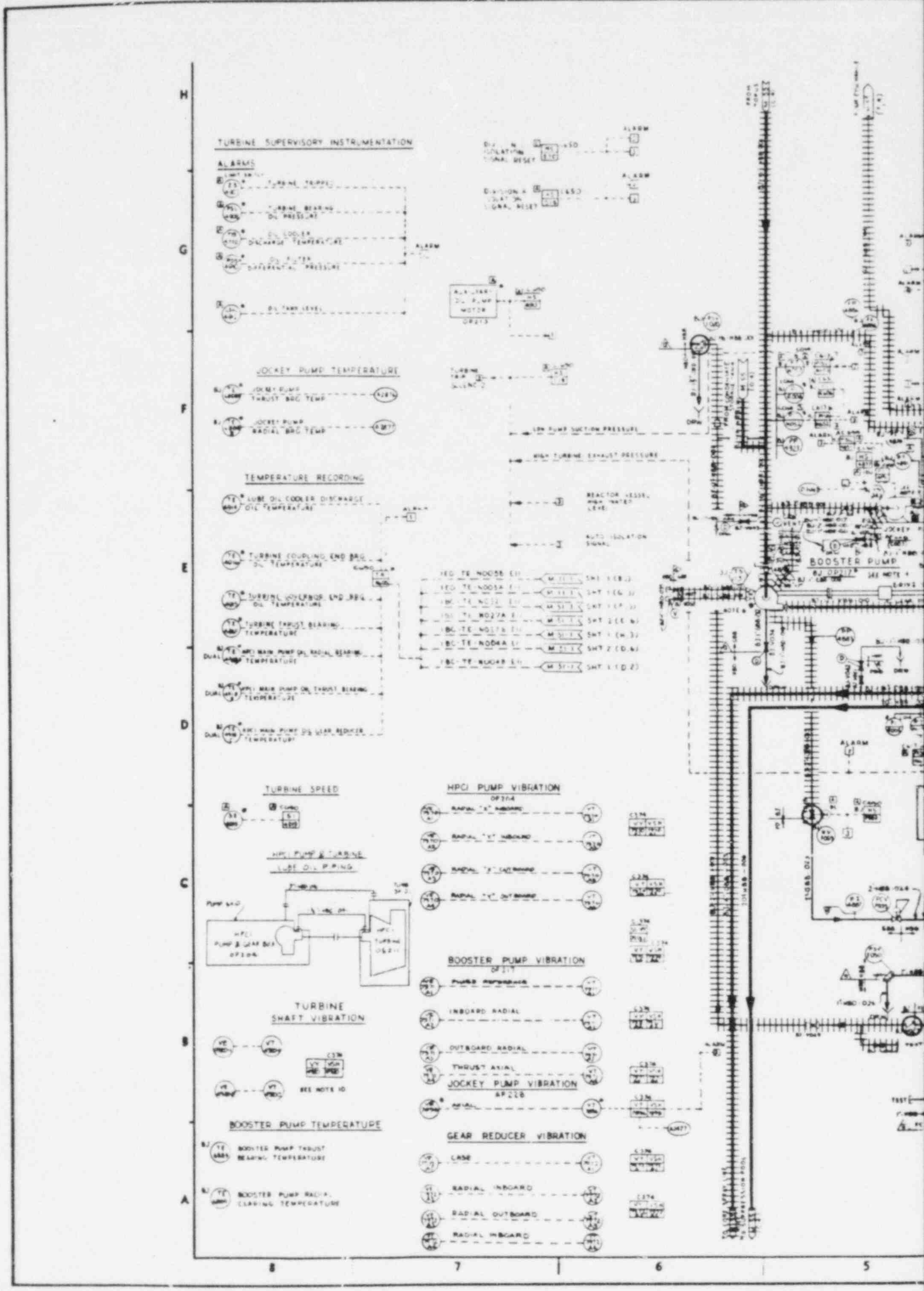
FINAL SAFETY ANALYSIS REPORT

HPCI AS AN EXTENDED CONTAINMENT BOUNDARY

FIGURE 6.2-46
SHEET 1 OF 2

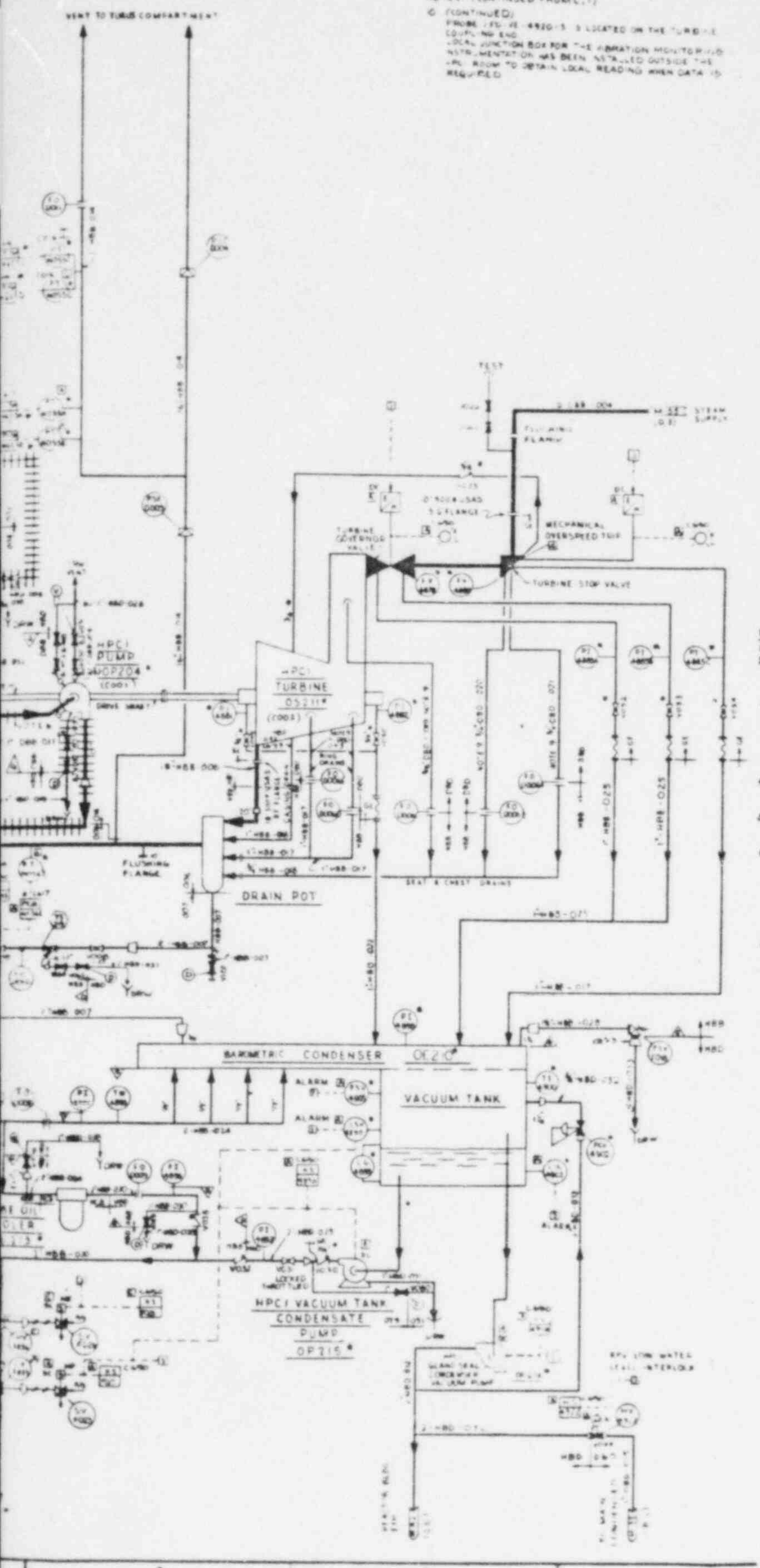
Amendment 13, 11/85

FOR INFORMATION ONLY



NOTES: (CONTINUED FROM C,1)

10 (CONTINUED)
PROBE (FD-VE-4920-5) IS LOCATED ON THE TURBINE COUPLING END.
LOCAL JUNCTION BOX FOR THE VIBRATION MONITORING INSTRUMENTATION HAS BEEN INSTALLED OUTSIDE THE HPCI ROOM TO OBTAIN LOCAL READING WHEN DATA IS REQUIRED.



LEGEND

□ ISOLATION VALVE FOR PROCESS PENETRATION WITH ONLY ONE ISOLATION VALVE

△ ISOLATION VALVE FOR PROCESS PENETRATION WITH REDUNDANT ISOLATION VALVES

○ SYSTEM ISOLATION VALVES ASSOCIATED WITH PRIMARY CONTAINMENT ISOLATION

┼┼┼┼ INDICATES THE EXTENDED CONTAINMENT BOUNDARY AFTER A SINGLE FAILURE

NOTES:

1. THE BJ MPL NUMBER FOR THIS SYSTEM IS E-41.
2. THE BAROMETRIC CONDENSER AND VACUUM TANK SHALL BE LOCATED SO THAT ITS WATER LEVEL IS BELOW THE BOTTOM OF THE TURBINE EXHAUST.
3. THIS P&ID CONTAINS SYSTEMS OR PORTIONS OF SYSTEMS:
   BJ - HIGH PRESSURE COOLANT INJECTION
   FD - HPCI TURBINE STEAM
   BC - RHR
   EG - SACS
4. PROVIDE BJ-3/4"-HBD-039 TO DRW AS DRIP PAN DRAIN FOR HPCI PUMP AND BOOSTER PUMP.
5. JOCKEY PUMP SEAL DRAIN WILL BE PIPED IN FIELD TO DRIP PAN.
6. CASING DRAIN ON PUMP OP217 SUCTION TO BE PLUGGED. CASING DRAIN ON OP208 DISCHARGE TO BE CAPPED.
7. DELETED
8. ROOT VALVES FOR NON Q PRESSURE GAGE IMPULSE LINES CONNECTED TO ASME SECTION III CLASS 2 OR CLASS 3 PIPE ON THIS P&ID SHALL REMAIN IN THE OPEN POSITION ONLY WHILE BEING READ BY AN OPERATOR OTHERWISE THESE VALVES SHALL REMAIN IN CLOSED POSITION.
9. LINE NUMBERS 1"-HBD-082, 1"-DBD-045, 3/4"-DBD-034, 3/4"-DBD-020 & 3/4"-DBD-231 ARE TO BE DESIGNED, FABRICATED AND INSTALLED TO Q, ASME III CLASS 2 REQUIREMENTS. SINCE PIPE CAN'T BE HYDROTESTED THESE LINES ARE CLASSIFIED AS ANS PIPING.
10. VIBRATION PROBES FD-VE-4920-3 AND FD-VE-4920-4 ARE LOCATED ON THE INBOARD AND OUTBOARD BEARING CAPS ACCORDINGLY. KEYPHASOR (CONTINUED AT H,5)

THIS FIGURE IS BASED ON M-56-1 BUT HAS BEEN FROZEN AT REV. 12.

~~M-56-1, REV 12~~

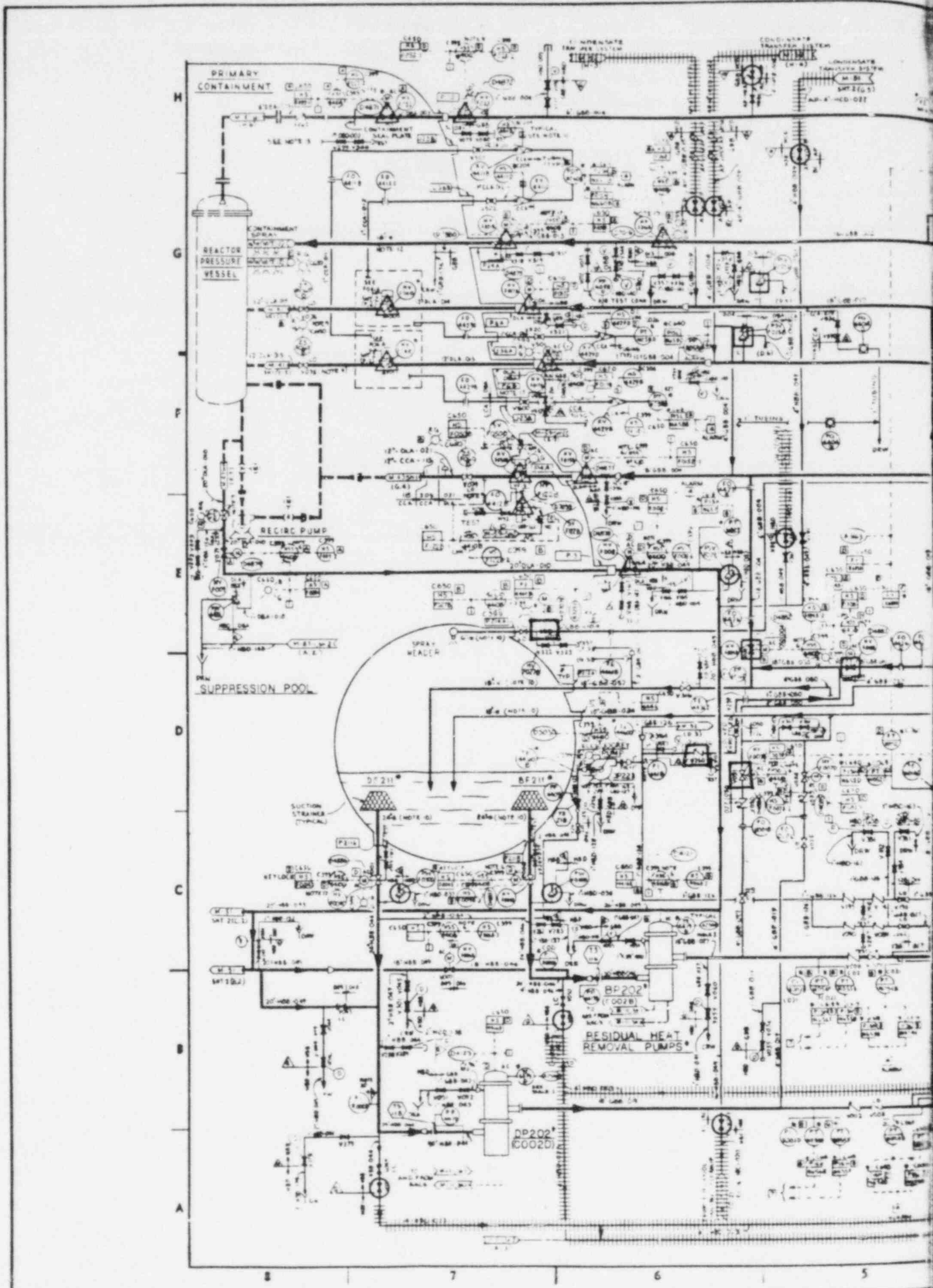
HOPE CREEK GENERATING STATION

FINAL SAFETY ANALYSIS REPORT

HPCI AS EXTENDED CONTAINMENT BOUNDARY

FIGURE 6.2-46
SHEET 2 OF 2

Amendment 13, 11/85


PRIMARY CONTAINMENT
REACTOR PRESSURE VESSEL
CONTAINMENT SPRAY
CONDENSATE TRANSFER SYSTEM
CONTAINMENT SEAL PLATE
RECIRC PUMP
SPRAY HEADER
SUPPRESSION POOL
SUCTION STRAINER (TYPICAL)
DP211
BP211
BP202
(C002B)
RESIDUAL HEAT REMOVAL PUMPS
DP202
(C002D)
KEYLOCK
H
G
F
E
D
C
B
A
8
7
6
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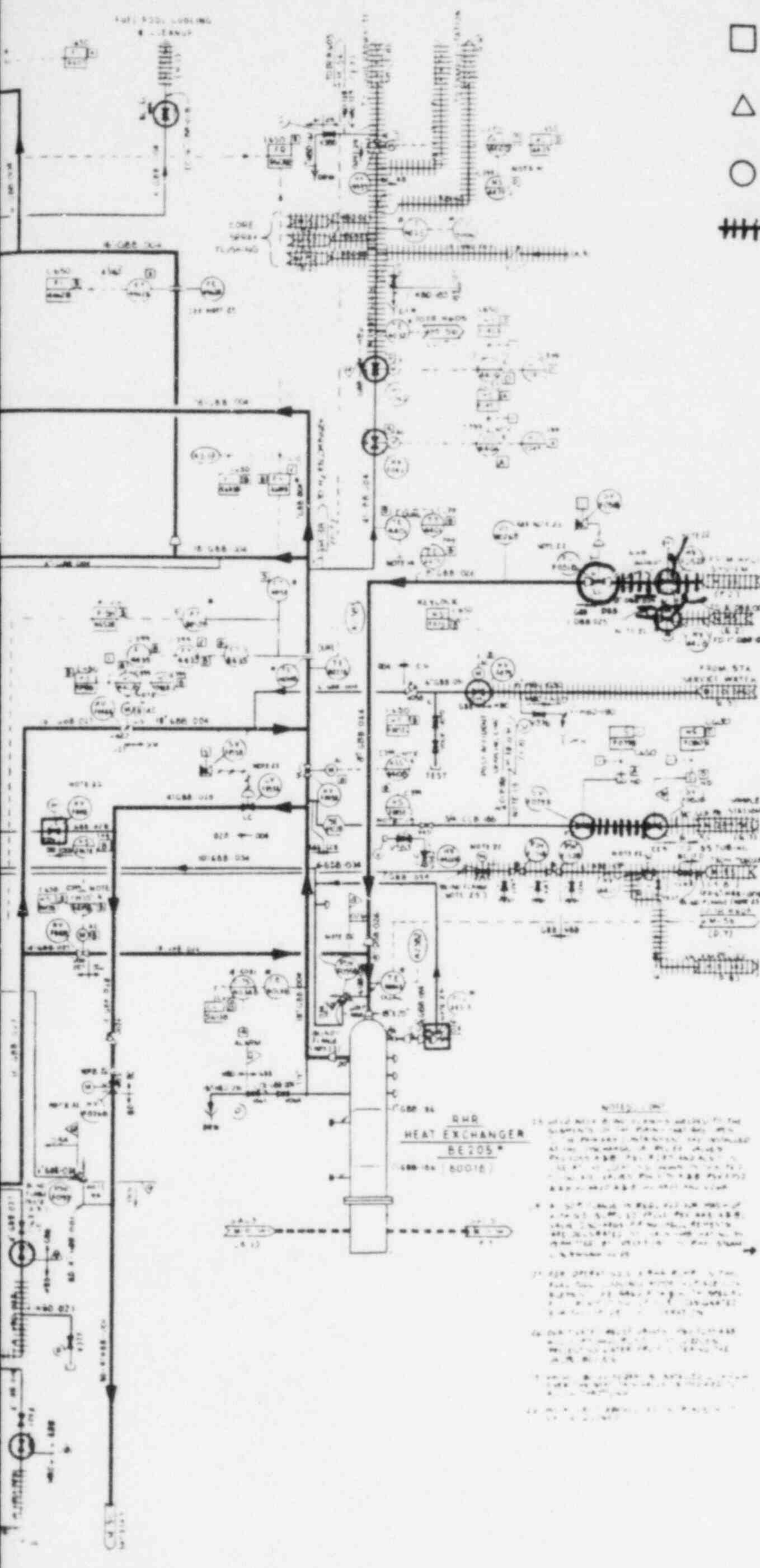


LEGEND

☐ ISOLATION VALVE FOR PROCESS PENETRATION WITH ONLY ONE ISOLATION

△ ISOLATION VALVE FOR PENETRATION WITH REDUNDANT ISOLATION VALVES

○ SYSTEM ISOLATION VALVE ASSOCIATED WITH PRIMARY CONTAINMENT ISOLATION

HHH INDICATES PORTIONS OF THE SYSTEM THAT ARE NOT PART OF THE EXTENDED CONTAINMENT BOUNDARY AFTER SINGLE FAILURE

NOTES:

1. [illegible]
2. TEMPERATURE [illegible] IS SHOWN ON P&ID [illegible]
3. TEMP ELEMENTS [illegible] ARE SHOWN IN RACS P&ID [illegible]
4. DELETED
5. CHEMICAL CLEANING CONNECTIONS TO BE ADDED LATER AS NECESSARY
6. PROVISIONS SHALL BE MADE TO TRANSFER CONTROL FROM THE CONTROL ROOM TO THE REMOTE SHUTDOWN PANEL [illegible]
7. THIS P&ID CONTAINS SYSTEMS OR PORTIONS OF SYSTEMS:
   - AB-MAIN STEAM
   - AP-CONDENSATE STORAGE & TRANSFER
   - BC-RESIDUAL HEAT REMOVAL
   - BD-REACTOR CORE ISOLATION COOLING
   - EA-STATION SERVICE WATER
   - EC-FUEL POOL COOLING & CLEANUP
   - [illegible]
   - [illegible]
8. A COMMON SUMMARY ALARM IS USED BY ALL OF THE ECCS FLOODING ALARM. SEE REFERENCES 4&5
9. FOLLOWING VALVES HAVE GE NUMBERS SHOWN IN PARENTHESES: [illegible]
10. SEE CIVIL DRAWING 10855-C-0931-0(Q) FOR THE PRESSURE RATING MATERIAL AND CODE CLASS OF THIS PIPING INSIDE THE PRIMARY CONTAINMENT.
11. EXCESS FLOW CHECK VALVE STATUS LIGHTS AND RESET SWITCHES ARE LOCATED ON LOCAL PANELS AS NOTED. ALARMS AND COMPUTER READOUTS FOR ABNORMAL CONDITIONS WILL BE MONITORED FROM THE CONTROL ROOM. SEE REF. 6
12. SEE CIVIL DRAWING 10855-C-0929-0(Q) FOR THE PRESSURE RATING MATERIAL AND CODE CLASS OF THIS PIPING INSIDE PRIMARY CONTAINMENT
13. TEST LINE ATTACHED TO BLIND FLANGE WILL BE USED TO TEST VALVE HV-F022 BY BOLTING TO FLANGE IN HEAD SPRAY LINE. STORE TEST LINE NEARBY. ASSURE TONGUE & GROOVE FLANGE TO FLANGE MATING.
14. TE AND SPARE ELEMENT SHALL BE WIRED TO PANEL C399
15. JOCKEY PUMP SEAL DRAIN WILL BE PIPED IN FIELD TO DRIP PAN.
16. DELETED
17. THE FOLLOWING VALVES CLOSE ON TRANSFER TO REMOTE SHUTDOWN PANEL: HV-F021B, HV-F016B, HV-F017B, HV-F027B, HV-F010B, [illegible] HV-F021A, HV-F006A. RHR JOCKEY PUMP [illegible] RUN ON TRANSFER TO RSP. HV-F004D OPENS ON TRANSFER
18. RHR PUMP TEMP SENSORS ARE THERMOCOUPLES PHYSICALLY ATTACHED TO THEIR APPLICABLE BEARING
19. PIPE AND FITTINGS SHALL BE [illegible]
20. THE ROOT VALVE FOR PRESSURE GAUGES SHOWN ON THIS P&ID SHALL BE NORMALLY CLOSED FOR ISOLATION PURPOSES AND OPENED FOR THE DURATION OF THE MEASUREMENT
21. [illegible]
22. [illegible]

THIS FIGURE IS BASED ON M-51-1 BUT HAS BEEN FROZEN AT REV. 14.

~~M51-1 REV 14~~ ~~SHEET 1~~

HOPE CREEK GENERATING STATION

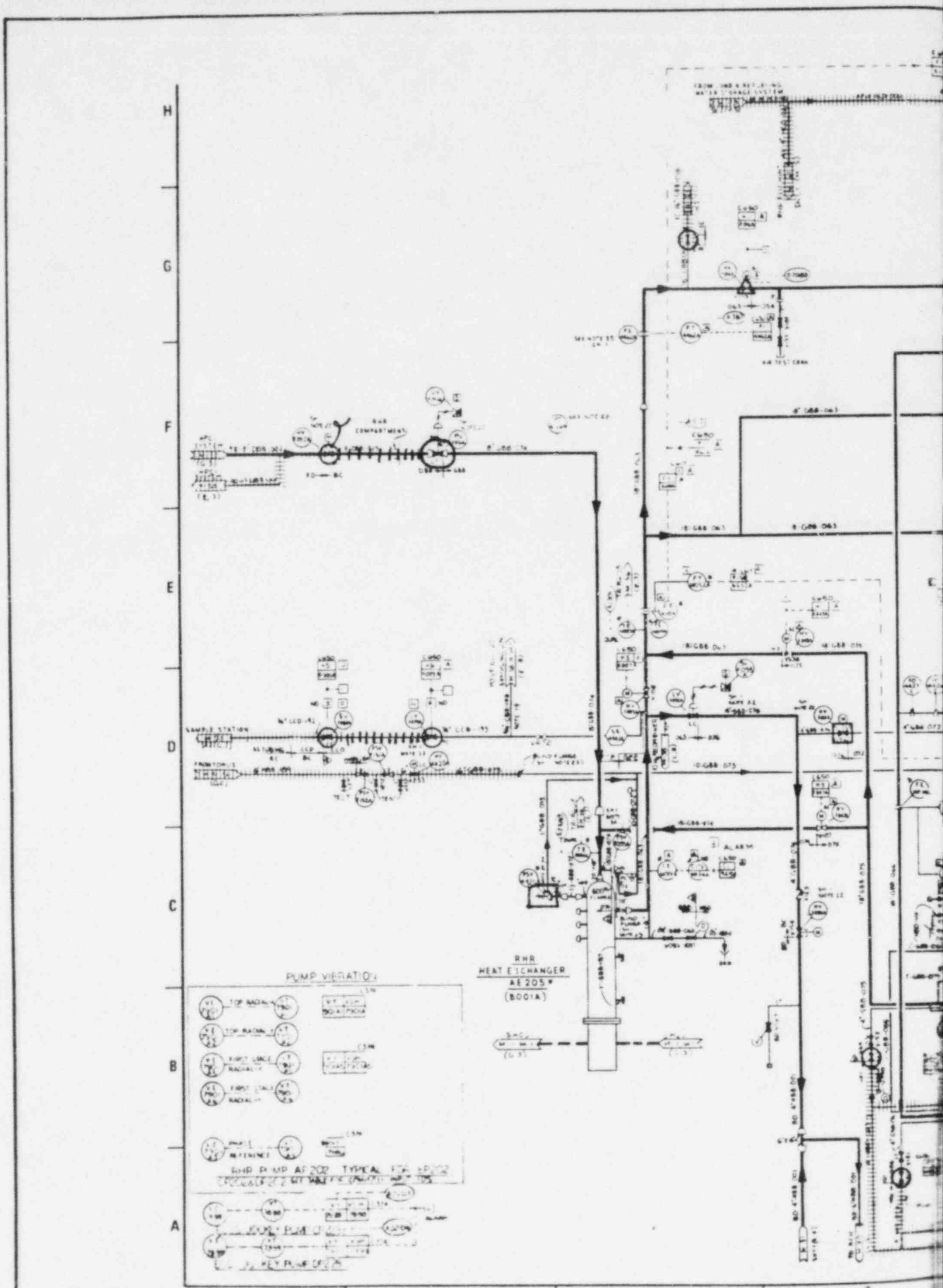
FINAL SAFETY ANALYSIS REPORT

RHR AND CORE SPRAY AS EXTENDED CONTAINMENT BOUNDARIES

FIGURE 6.2-47

SHEET 1 OF 3

Amendment 13, 11/85



H
G
F
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D
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B
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8
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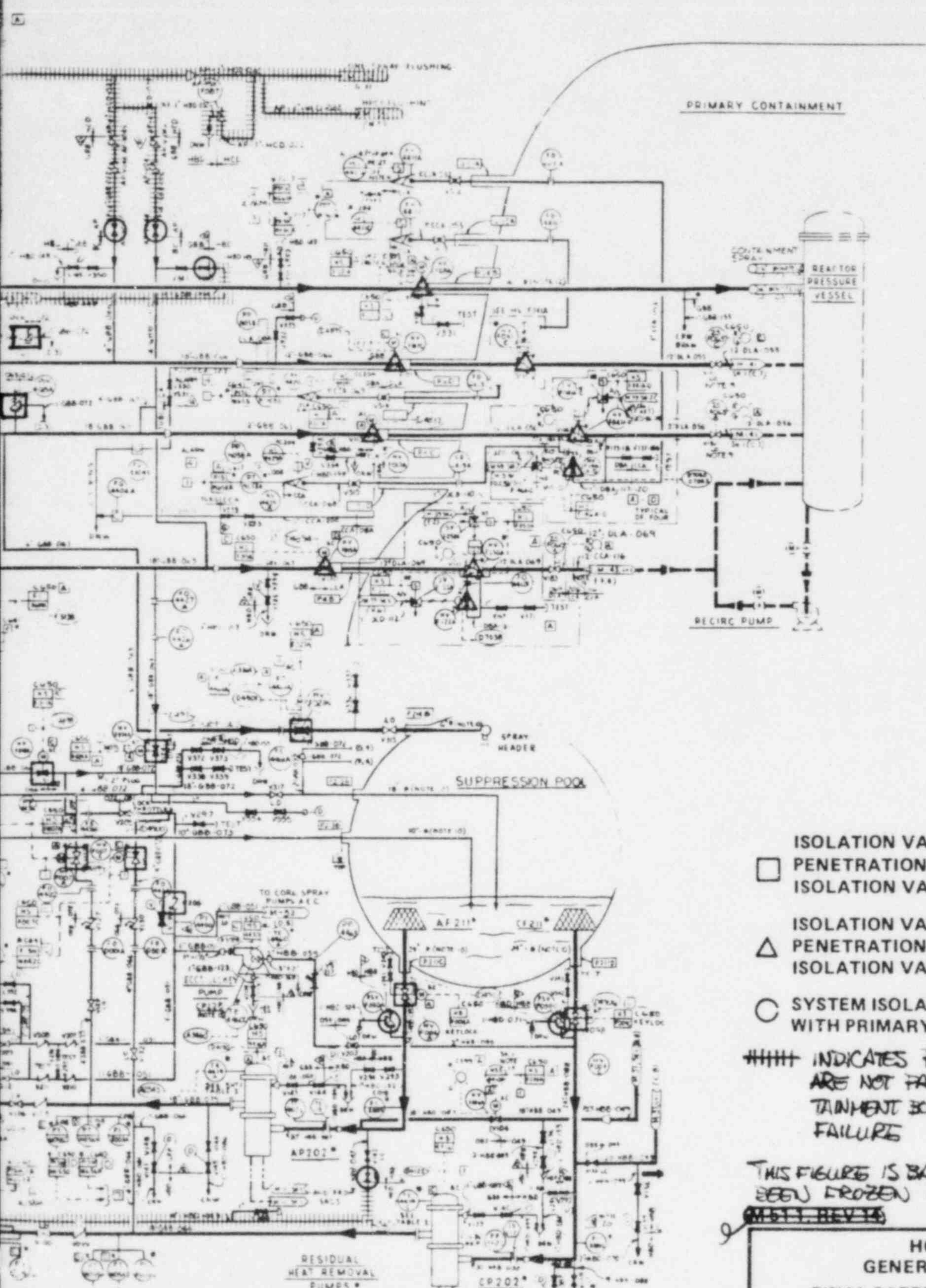
6
5
RHR COMPARTMENT
SAMPLE STATION
ALARM
RHR
HEAT EXCHANGER
AE205*
(B001A)
PUMP VIBRATION
TOP RADIAL
FIRST STAGE RADIAL
PHASE REFERENCE



□ ISOLATION VALVE FOR PROCESS PENETRATION WITH ONLY ONE ISOLATION VALVE

△ ISOLATION VALVE FOR PROCESS PENETRATION WITH REDUNDANT ISOLATION VALVES

○ SYSTEM ISOLATION VALVES ASSOCIATED WITH PRIMARY CONTAINMENT ISOLATION

┼┼┼┼┼ INDICATES PORTIONS OF THE SYSTEM ARE NOT PART OF THE EXTENDED CONTAINMENT BOUNDARY AFTER A SINGLE FAILURE

THIS FIGURE IS BASED ON M-51-1 BUT HAS BEEN FROZEN AT REV. 14

~~(M-51-1, REV 14)~~ ~~(SHEET 2)~~

HOPE CREEK GENERATING STATION

FINAL SAFETY ANALYSIS REPORT

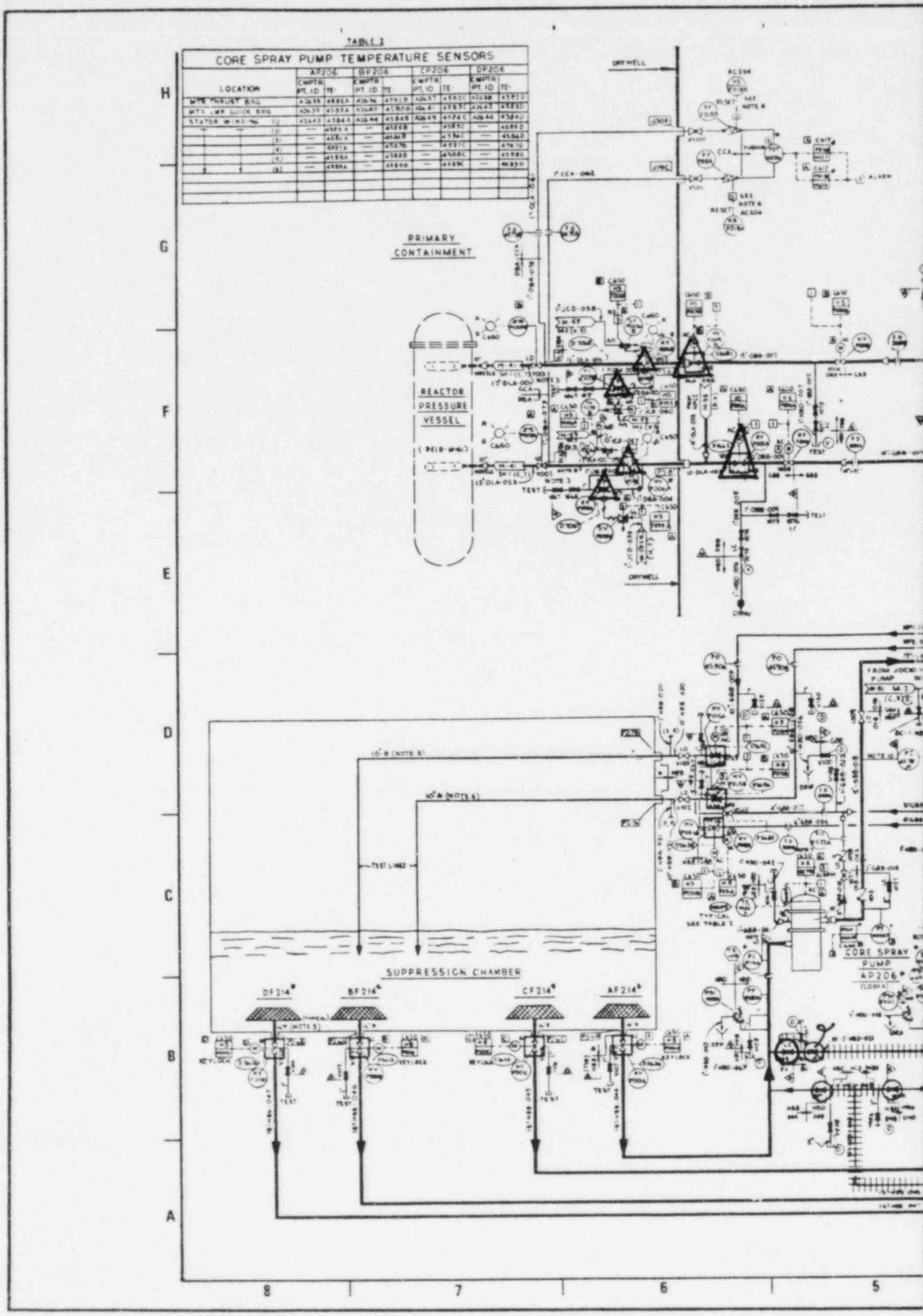
RHR AND CORE SPRAY AS EXTENDED CONTAINMENT BOUNDARIES

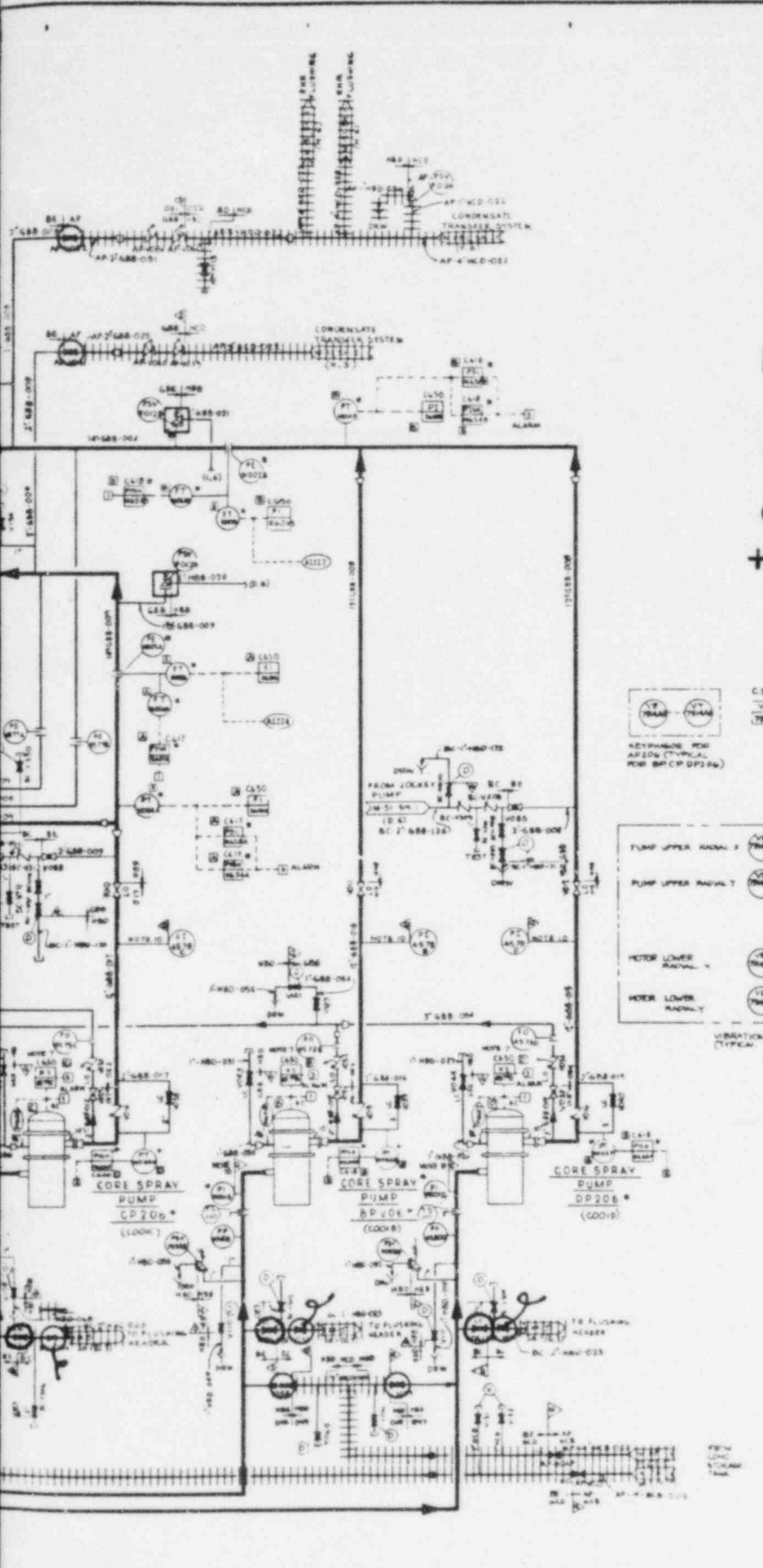
FIGURE 6.2-47
SHEET 2 OF 3

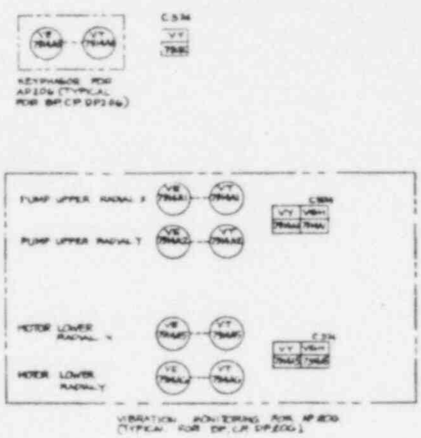
Amendment 13, 11/85

TABLE 1

CORE SPRAY PUMP TEMPERATURE SENSORS									
LOCATION		AP206 CMPTR PT. ID	AP206 TE-	BP206 CMPTR PT. ID	BP206 TE-	CP206 CMPTR PT. ID	CP206 TE-	DP206 CMPTR PT. ID	DP206 TE-
MTR THRUST BRG		A2635	4581A	A2636	4782B	A2637	4582C	A2638	4581D
MTR LWR GUIDE BRG		A2639	4583A	A2640	4583B	A2641	4583C	A2642	4583D
STATOR WINDING	(1)	A2643	4584A	A2644	4584B	A2645	4574C	A2646	4584D
	(2)	—	4585A	—	4586B	—	4585C	—	4685D
	(3)	—	4586A	—	4586B	—	4586C	—	4586D
	(4)	—	4587A	—	4587B	—	4587C	—	4767D
	(5)	—	4588A	—	4588B	—	4588C	—	4588D
	(6)	—	4589A	—	4589B	—	4589C	—	4689D







LEGEND

□ ISOLATION VALVE FOR PENETRATION WITH ONLY ONE ISOLATION

△ ISOLATION VALVE FOR PENETRATION WITH REDUNDANT ISOLATION VALVES

○ SYSTEM ISOLATION VALVES ASSOCIATED WITH PRIMARY CONTAINMENT ISOLATION

┼┼┼┼ INDICATES PORTIONS OF THE SYSTEM THAT ARE NOT PART OF THE EXTENDED CONTAINMENT BOUNDARY AFTER A SINGLE FAILURE

THIS FIGURE IS BASED ON M-52-1 BUT HAS BEEN FROZEN AT REV. 12

~~M-52-1, REV 12~~

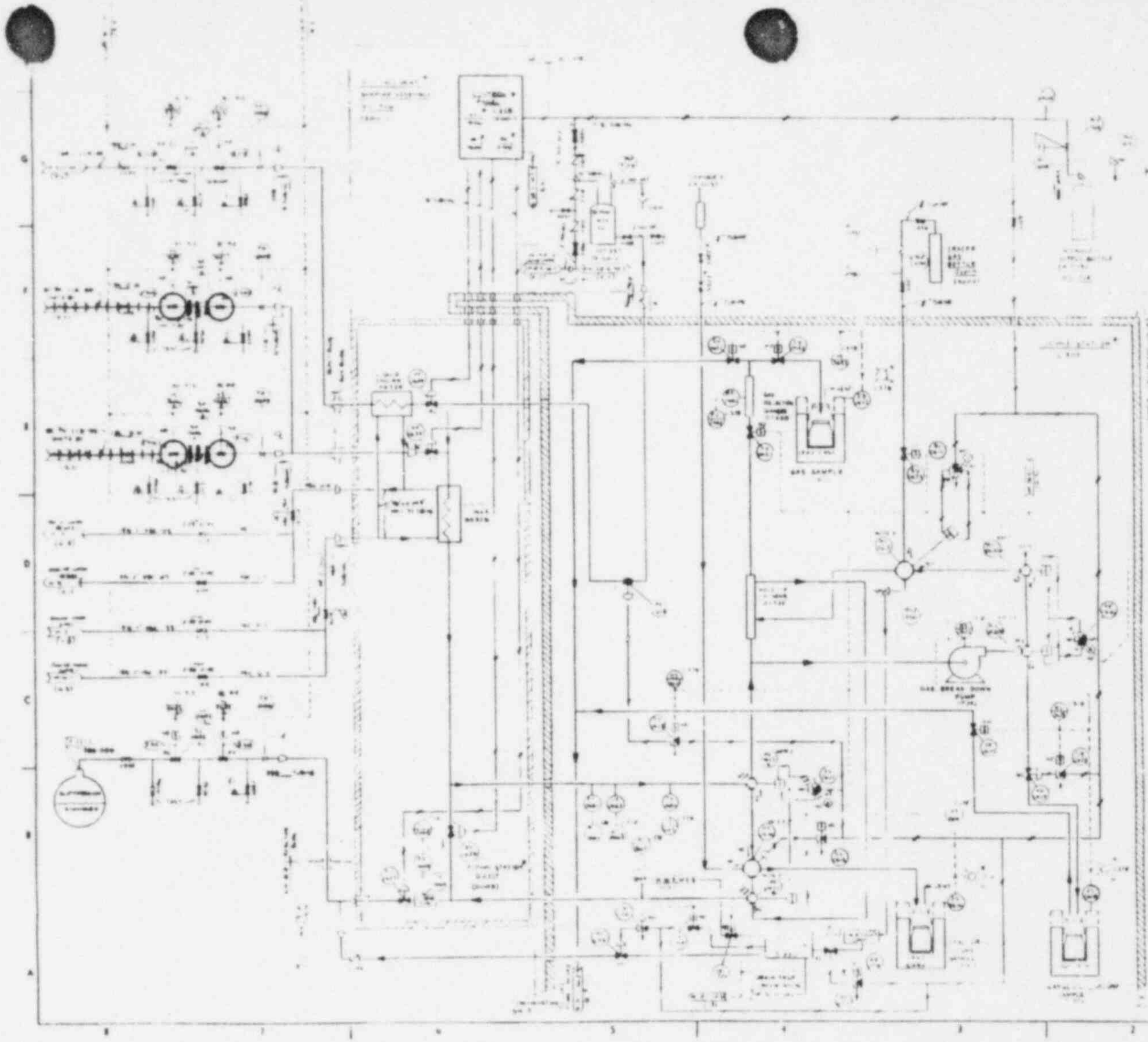
HOPE CREEK GENERATING STATION

FINAL SAFETY ANALYSIS REPORT

RHR AND CORE SPRAY AS EXTENDED CONTAINMENT BOUNDARIES

FIGURE 6.2-47
SHEET 3 OF 3

Amendment 13, 11/85



□ ISOLATION VALVE FOR PENETRATION WITH ONLY ONE ISOLATION VALVE

△ ISOLATION VALVE FOR PENETRATION WITH REDUNDANT ISOLATION VALVES

○ SYSTEM ISOLATION VALVES ASSOCIATED WITH PRIMARY CONTAINMENT ISOLATION

++++ INDICATES THE EXTENDED CONTAINMENT BOUNDARY AFTER A SINGLE FAILURE

THIS FIGURE IS BASED ON M-38-0 BUT HAS BEEN FROZEN AT REV. 1.

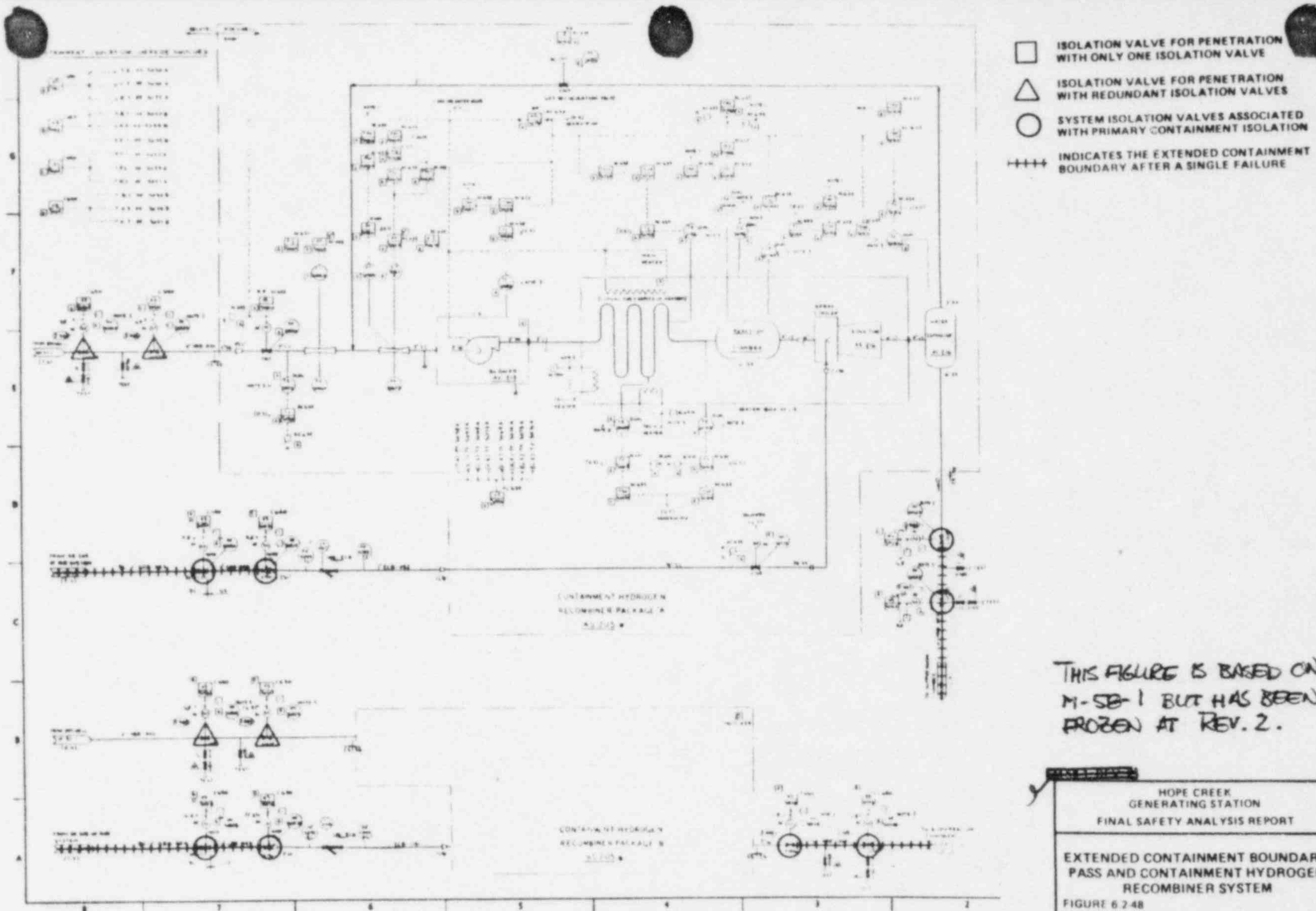
HOPE CREEK GENERATING STATION

FINAL SAFETY ANALYSIS REPORT

EXTENDED CONTAINMENT BOUNDARY PASS AND CONTAINMENT HYDROGEN RECOMBINER SYSTEM

FIGURE 6.2-48
SHEET 1 OF 2

Amendment 2, 10/83



THIS FIGURE IS BASED ON M-58-1 BUT HAS BEEN FROZEN AT REV. 2.

HOPE CREEK
GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

EXTENDED CONTAINMENT BOUNDARY PASS AND CONTAINMENT HYDROGEN RECOMBINER SYSTEM

FIGURE 6.2-48
SHEET 2 OF 2

Amendment 2, 10/83

such as prestartup valve lineup checks, suffice to reasonably ensure that such valves will not degrade ECCS performance. ~~Certain other valves are physically locked in their normal position. Access to the keys to the locks is controlled administratively.~~ In other cases, two isolation valves are provided in series to minimize the possibility of inter- or intra-system leakage. Position indication of manual valves that are in the main flowpaths of the ECCS, and that are inaccessible during normal plant operation, is provided in the main control room. Proper administrative controls and/or surveillance testing are relied upon to ensure the position of the remaining valves.

6.3.2.9 TMI Action Plans

See Section 1.10 for a discussion of TMI Task Action Plan requirements applicable to HCGS.

6.3.3 PERFORMANCE EVALUATION

The performance of the emergency core cooling system (ECCS) is determined through application of the 10 CFR 50, Appendix K evaluation models, and demonstrated conformance to the acceptance criteria of 10 CFR 50.46. The analytical models are documented in Section S.2.5.2 of GESTAR II (Reference 6.3-3).

The ECCS performance is evaluated for the entire spectrum of break sizes for postulated LOCAs. The accidents, as listed in Chapter 15, for which ECCS operation is required are:

a. Section 15.6.6 - Feedwater piping break

b. Section 15.6.4 - Spectrum of boiling water reactor (BWR) steam system piping failures outside of containment

c. Section 15.6.5 - LOCAs

Chapter 15 provides a description of the radiological consequences of the events listed above.

a. Two 100%-capacity air handling units, including low and high efficiency filters, fans, chilled water cooling coils, and electric heating coils, are provided for use during normal operation or following an accident. Electric pan humidifiers are provided for use during normal operation.

b. Two 100%-capacity return air fans are provided for use during normal plant operation and following a design basis accident (DBA).

c. Two 100%-capacity emergency air filtration units are provided for use following an accident. Each unit has its own fan, low efficiency prefilters, electric heating coils, upstream high efficiency particulate air (HEPA) filters, charcoal adsorbers, and downstream HEPA filters.

d. An exhaust fan is provided to exhaust air from the control room, and toilet facilities during normal operation.

WITH PLENUM, THROUGH A COMMON MISSILE SHIELDED TUBE

e. Two separate outside air intakes are provided for use during normal operation or following a DBA.

f. The dampers for control room isolation purposes are bubble-tight with a closure time of 5 seconds maximum.

6.4.2.3 Leaktightness

Control room envelope construction joints and penetrations for cable, pipe, HVAC duct, HVAC equipment, dampers, and doors are designed specifically for leaktightness. A list of potential leak paths to the control room is provided in Table 6.4-1, along with the type of material, joint, or penetration. Periodic tests to verify control room leaktightness are discussed in Section 6.4.5.

The control room envelope is constructed for an outleakage rate of less than 1000 cfm at 1/8-inch water gauge positive pressure relative to the control room adjacent areas. The 1000 cfm leakage rate is equivalent to 1.1 control room volume changes per

system consists of two 100%-capacity trains, each supplied by a separate Class 1E power system and interlocked with one of the CRS/CRRA systems. Each CREF train consists of an outside air connection to the CRS outside air intake plenum, radiation sensor, tornado damper, smoke detector, outside and return air dampers, fan, 80 to 85% ASHRAE dust spot efficiency filters, electric heating coil for humidity control, upstream high efficiency particulate air (HEPA) filter, charcoal adsorber, a downstream HEPA filter, and a discharge damper. The CREF system may operate in one of the two following modes:

a. A pressurizing mode in which 1000 cfm of outside air is mixed with 3000 cfm of control room return air before entering the CREF unit, thus pressurizing the control room envelope above the surrounding space This mode is an automatic mode following a detection of high airborne radioactivity in the control room normal air intake.

b. The operator can override the control room pressurization mode to initiate isolation mode by manually closing the outside air intake isolation damper for the operating CREF unit. However, this mode is not AUTOMATICALLY used following a radiological accident. The recirculation (isolation) mode is circulating 4000 cfm of return air, without introduction of outside air, through a CREF unit.

6.4.4 DESIGN EVALUATIONS

The control room habitability system is designed with redundancy and separation of active components to provide reliable operation under normal conditions and to ensure operation under accident conditions. The design basis accident (DBA) radiation source terms used for control room dose evaluation are in accordance with NUREG-0737, Item III.D.3.4., Control Room Habitability Requirements.

6.4.4.1 Radiological Protection

A detailed discussion of the dose calculation model for control room operators following the postulated DBA is provided in Section 6.4.7.

The design basis accidents have been evaluated to determine the worse case accident scenario for control room habitability design purposes. The control room operator doses can be derived for each of the accidents by the methodology described in Section 6.4.7 with the radiation source terms defined in the appropriate sections in Chapter 15 and the release locations relative to the control room intake shown in Figure 6.4-2 and Table 6.4-6.

The release location for the DBA LOCA, fuel handling accident, main steam line break accident and instrument line break accident which occur inside primary containment and the reactor building is the FRVS exhaust vent at the top of the reactor building. The release location for the control rod drop accident, main steam line break accident, and offgas system failure which occur in the turbine and radwaste buildings is the south plant vent. The offgas system failure could also result in releases from the north plant vent depending upon the actual accident location in the building. The release location for the main steam line break accident which occur in the main steam tunnel is the blowout panels located between the reactor building and the south plant vent.

The release location for the HPCI steam supply line break accident, which occurs in the reactor building at elevation 63'-0", is the reactor building blowout panels located in the west
TO BE wall of the reactor building. The radiation source term for this accident can be conservatively assumed equivalent to the main steam line break for purposes of this evaluation. ~~The expected mass release is approximately 50% of the main steam line break which would result in a much lower source term~~.

Of all the accidents releasing from the FRVS exhaust vent, the highest source term ~~and longest duration~~ results from the DBA LOCA. Releases from the south plant vent occur from accidents which have lower source terms and a smaller atmospheric dispersion factor with respect to control room intake LOCA. ~~Further, although~~ The main steam line break and HPCI line break
SMALLER have ~~higher~~ source terms~~, the duration of the accident is shorter~~ in comparison to the DBA LOCA. Therefore, the consequences are less. Consequently, the DBA LOCA has been determined to result in the controlling accident conditions and has been designated the worst case accident scenario for control room habitability design purposes. The resulting calculated doses for control room occupancy on a rotating shift basis, for the reactor building design basis inleakage rate, are shown in Table 6.4-4 and are less than 5 rem to the whole body or the

d. f_5, Time averaging effects - Wind speed variation and wind direction meandering effects are not modeled in wind tunnel tests. To account for this effect, NUREG/CR-1474, indicates that the following formulation should be used:

$$C_p = C_m \; (t_p/t_m)^{-1/2} \qquad (6.4\text{-}4)$$

where:

C_p = prototype concentration

C_m = model concentration

t_p = prototype sampling times

t_m = model equivalent field sampling times

Therefore, scaling 3 to 10 minute wind tunnel data up to 1-hour X/Qs results in a reduction factor of 0.4. Scaling from wind tunnel data to 8-hour X/Qs would result in a reduction factor of 0.14. Time averaging effects can have large effects in the calculated X/Qs, but these effects have not been tested fully for building wake conditions. Therefore, a value of 0.5 for f_5 is conservatively estimated.

Based upon the above parameters, an X/Q was calculated as follows for the 0 to 8 hour time period:

$$X/Q = \frac{K}{A\bar{u}} \times f_1 \times f_2 \times f_3 \times f_4 \times f_5$$

For the diesel exhaust,

$\boxed{4560}$

$$(X/Q)_{DE} = \frac{3}{\cancel{\text{[illegible]}} \times 1.28} \times 1 \times 1 \times 0.2 \times 1 \times 0.5$$

The removal constant, λ_L, for loss of activity due to outleakage, assuming that air leaves the control room at the same rate which it enters, is given by:

$$\lambda_L = \frac{\cancel{F(60)}\ \boxed{(F+F_1)(60)}}{V} \qquad (6.4\text{-}8)$$

For activity entering the main control room during the period of interest, the following equation is obtained:

$$\frac{dI_1}{dt} = Q-(\lambda D + \lambda R + \lambda L)\ I_1 \qquad (6.4\text{-}9)$$

where:

I_1 - = inventory of radioactivity in the control room due to the activity that enters during the period of interest, Ci

t = time from initiation of the event, h

Solving equation 6.4-9 for I_1, using the initial conditions that $I_1 = 0$ at $t = t_1$ and Q equal to a constant for the period, yields the following equation:

$$I_1 = \frac{Q\ [1 - \exp - (\lambda_t\ (t-t_1))]}{\lambda_t} \qquad (6.4\text{-}10)$$

where:

λ_t = $\lambda_D + \lambda_R + \lambda_L$

t_1 = time at the beginning of the period of interest, h

6.8 FILTRATION, RECIRCULATION, AND VENTILATION SYSTEM

The filtration, recirculation, and ventilation system (FRVS) consists of two subsystems that are required to perform post-accident, safety-related functions simultaneously. These subsystems are:

a. Recirculation system - The FRVS recirculation system is an engineered safety feature (ESF) system, located inside the reactor building, that reduces offsite doses significantly below 10 CFR 100 guidelines during a loss-of-coolant accident (LOCA), refueling accident, or high radioactivity in the reactor building. Upon reactor building isolation, the FRVS recirculation system is actuated and recirculates the reactor building air through filters for cleanup. This subsystem is the initial cleanup system before discharge is made via the FRVS ventilation subsystem to the outdoors.

b. Ventilation system - The FRVS ventilation system is an ESF system, located inside the reactor building, that maintains the building at a negative pressure with respect to the outdoors. The system takes suction from the discharge duct of the FRVS recirculation system and discharges the air through filters to the outdoors via a vent at the top of the reactor building.

6.8.1 FRVS RECIRCULATION SYSTEM

6.8.1.1 Design Bases

The FRVS recirculation system is designed to accomplish the following objectives:

a. Recirculates and filters the air in the reactor building following a LOCA, or other high radioactivity accident, to reduce the concentration of radioactive halogens and particulates potentially present in the reactor building. See Figure 9.4-3 for design airflow rates in the reactor building. The circulating rate is APPROXIMATELY 3% [redacted] of reactor building free volume per minute

The filter-demineralizer system also services the torus water cleanup system for the purification of suppression pool water.

The stainless steel filter-demineralizer vessels are of the pressure precoat type. A tube nest assembly consisting of the tube sheet, clamping plate, filter elements, and support grid is inserted as a unit between the flanges of the vessel. The filter elements are stainless steel and are mounted vertically in the vessel. Air scour connections are provided below the tube sheet, and vents are provided in the upper head of each vessel. The filter elements are installed and removed through the top of each vessel. The holding elements are designed to be coated with powdered ion exchange resin as the filtering medium.

The fuel pool filter-demineralizers maintain the following effluent water quality specifications:

Specific conductivity at 25°C, micromho/cm	≤0.3
pH at 25°C	6.0 to 7.5
Heavy elements (Fe, Cu, Ni), ppm	<0.05
Silica (as SiO_2), ppm	<0.05
Chloride (as Cl-), ppm	<0.02
Total suspended solids, ppm	90% removal to a minimum of 0.01 ppm

INFLUENT AND EFFLUENT WATER ARE

The influent and effluent water of the spent fuel pool filter demineralizer is continuously monitored by on-line pH and conductivity instrumentation. In addition, grab samples of the analyzed weekly for Cl, suspended solids, silica, and gamma isotopics, and monthly for the heavy elements.

Decontamination factors (df) of > 10 are expected for any Cl- and suspended solids and > 5 for isotopes of I and Co. Resin beds will be regenerated and/or replaced when these df's are not achieved.

The spent fuel pool demineralizer will be operated as required to maintain radiation levels on the refueling platform less than 2 mrem/hr.

extruder/evaporator turntables to the capper/scanner infeed conveyor and replaces them with empty drums.

kk. Solid radwaste bridge crane (00H317)

This 7-1/2-ton double girder crane is located above elevation 102 feet in the auxiliary building. It also serves the radwaste drum storage area loft at elevation 126.5 feet. It moves filled 55-gallon drums within the storage area, unloads the outfeed conveyor, assists in removing the shipping cask lid, and in truck loading.

ll. SACS pumps hoist

DE-RATED TO 4-TONS WORKING CAPACITY, ARE PROVIDED

DESIGN

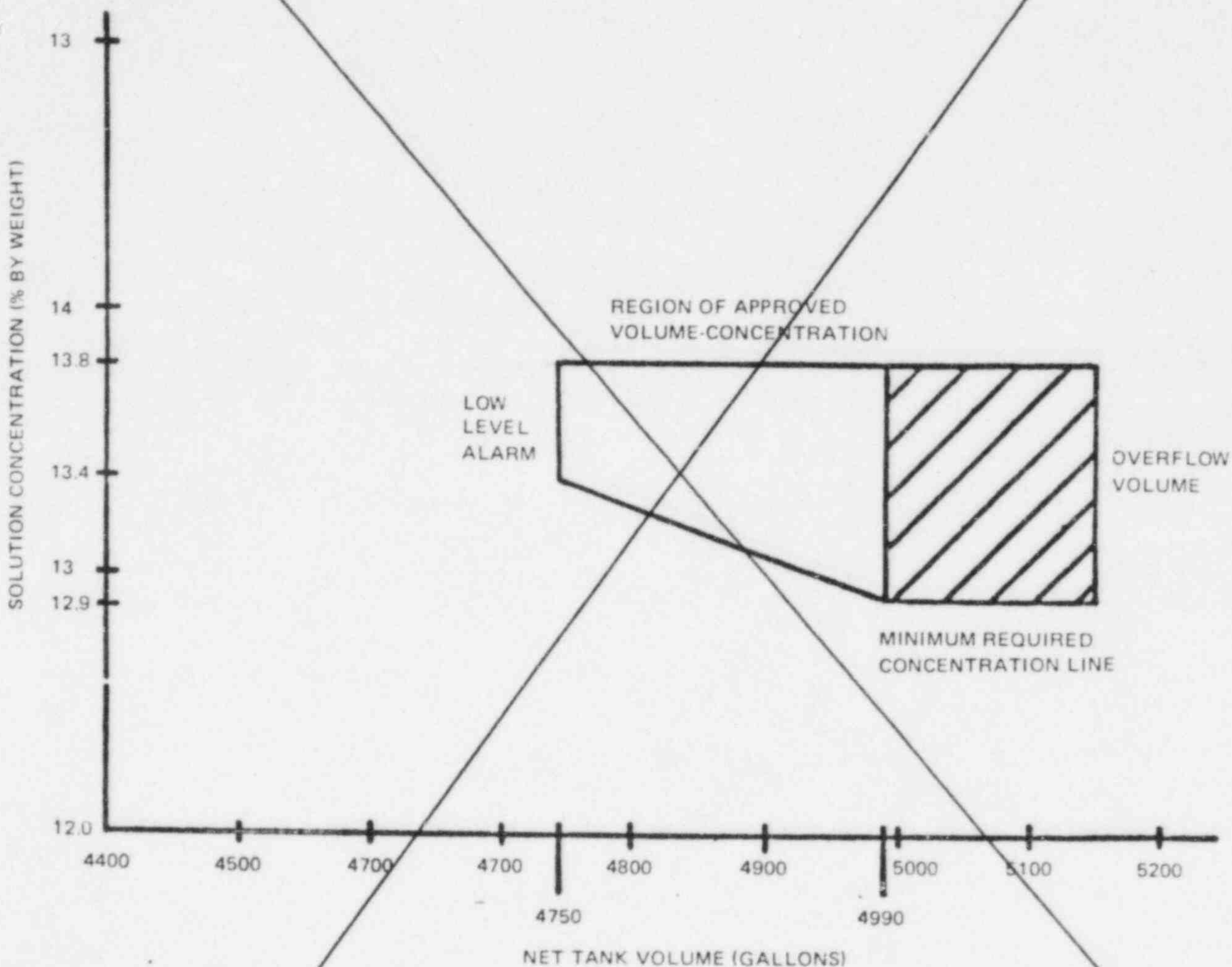
Fifteen-ton capacity monorails above the SACS pumps ~~are designed~~ to accommodate hoists for removal of the pump motors. One monorail serves pumps A and C in SACS loop A, and the other serves pumps B and D in loop B. The monorails are located above elevation 102 feet in the reactor building. The top of each rail is at elevation 126 feet 10.75 inches. Because dedicated SACS pump hoists were not purchased, they will be borrowed from other locations when needed.

mm. SACS heat exchanger hoist

Two parallel 5-ton capacity monorails at one end of each SACS heat exchanger are designed to accommodate hoists for removal of the heat exchanger end covers. One set of monorails serves both SACS loop A exchangers, and the other set serves the loop B exchangers. The monorails are located above elevation 102 feet in the reactor building. The top of each rail is at elevation 127 feet 1 1/2 inches. Because dedicated SACS heat exchanger hoists were not purchased, they will be borrowed from other locations when needed.

nn. Recombiner system hoists (00H318, 10H318)

These 1-1/2 (00H318) and 2-1/2 (10H318) ton capacity chain-operated monorail hoists are located above elevation 67 feet 3 inches in the service and radwaste



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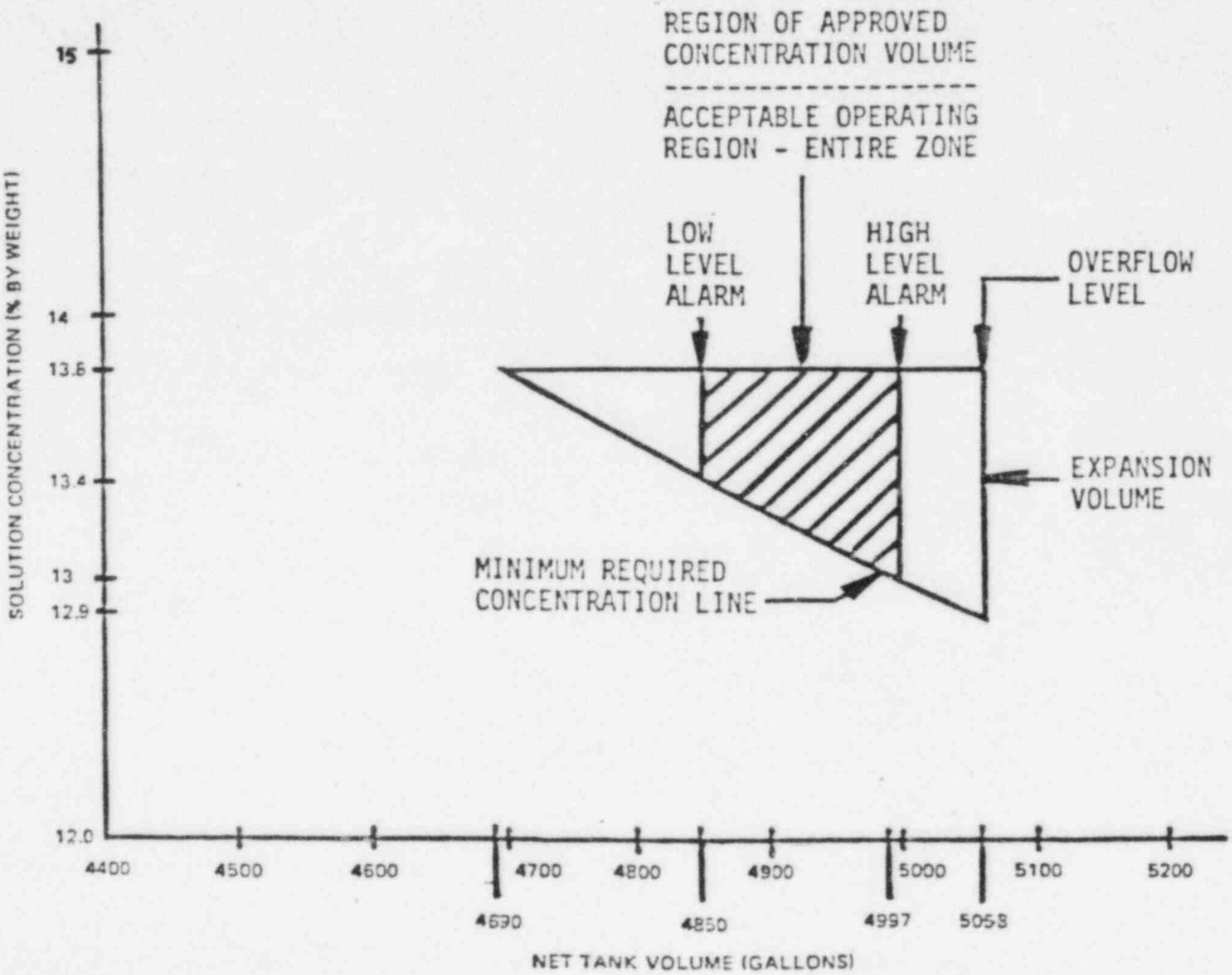
HOPE CREEK
GENERATING STATION

FINAL SAFETY ANALYSIS REPORT

SODIUM PENTABORATE
($Na_2B_{10}O_{16} \cdot 10H_2O$)
VOLUME CONCENTRATION
REQUIREMENTS

FIGURE 9.3-9



HOPE CREEK
GENERATING STATION

FINAL SAFETY ANALYSIS REPORT

SODIUM PENTABORATE
$(Na_2B_{10}O_{16} \cdot 10H_2O)$
VOLUME CONCENTRATION
REQUIREMENTS

FIGURE 9.3-9

Material Description	Quantity	Plant Location	Condition of Use	Approximate Time of Use
Air bottle	1 at 230 scf	Circulating water structure, el 106'-0"	2200 psig	Intermittently - air supply for fire protection sprinkler system.
Liquid petroleum gas bottles	6 at 100 lbs	Yard - next to auxiliary boiler building (west side)	20 psig	Intermittently - (ignition of auxiliary boilers)
INSERT				
Corrosives (acids, caustics)				
Sulfuric acid	21,000 gal.	Yard-near cooling towers	Solution, 66° Be	Continuous
Sodium hypochlorite	90,000 gal.	Yard-near cooling towers	Solution 15% by wt	90 min/day
Sodium hypochlorite	45,000 gal.	Yard-near intake structure	Solution 15% by wt	90 min/day
Sodium hypochlorite	55 gal. drum	Aux boiler bldg domestic water tanks (yard)	Solution 15% by wt	12 h/day
Caustic soln	150 gal.	Aux bldg - control area, el 121'	Solution 50% by wt	90 min/day
Caustic soln	200 gal.	Aux bldg - RW/service area, el 124'	Solution 25% by wt	16 h/day (refueling) 5-1/2 h/day (normal)
Caustic soln	250 gal.	Aux bldg - control area, el 102'	Solution 4% by wt	30 min/2.5 days
Sulfuric acid	250 gal.	Aux bldg - control area, el 102'	Solution 4% by wt	30 min/2.5 days
Caustic, tank 00T-140	16,000 gal.	Turb bldg, el 54'	Solution 50% by wt	2.5 h per regen of 1 service vessel resin per 30 days
Sulfuric acid	16,000 gal.	Turb bldg, el 54'	Solution, 60° Be	2.0 h per regen of 1 service vessel resin per 30 days
Caustic, tank 00T-141	16,000 gal.	Turb bldg, el 54'	Solution 50% by wt	
Sulfuric acid	16,000 gal.	Turb bldg, el 54'	Solution, 60° Be	
Sodium pentaborate soln, SLC storage tank	5388 gal.	RB, el 162'	Liquid	Used to shut down reactor following scram failure (≤ 1 time/40 yr)

INSERT FOR TABLE 9.5-3 PAGE 3 OF 5

Nitrogen Bottles	12 at 304 ft^3 each (6 per accumulator)	Emergency Diesel Generator Fuel Oil Storage Area, EL 54', Room 5106	165 psig	Intermittently - maintains SACS accmumlator tanks water level as required

11.2 LIQUID WASTE MANAGEMENT SYSTEM

The liquid waste management system (LWMS) is designed to collect, store, process, and dispose of or recycle all radioactive or potentially radioactive liquid waste generated by plant operation or maintenance.

The LWMS consists of five process subsystems, each for collecting, storing, processing, monitoring, and disposal of specific types of liquid wastes in accordance with their conductivity, chemical composition, and radioactivity. These systems are:

a. Equipment drain (high purity waste)

b. Floor drain (low purity waste)

c. Regenerant waste (high conductivity waste)

d. Chemical waste (decontamination solution waste and chemistry lab drains)

e. Detergent drain waste (laundry waste and personnel decontamination drains).

These systems are shown on Figures 11.2-1, 11.2-2, 11.2-3, and 11.2-4. Equipment locations are shown on drawings provided in Section 1.2. The radioactive waste drainage system, a major input source to the LWMS, is described in Section 9.3.3. The equipment and floor drainage collection system in shown on Figure 9.3-7.

DEMINERAL-IZED WATER

1.0

Sufficient treatment capability is available to process liquid waste to meet ~~condensate~~ quality requirements for plant reuse (conductivity value of ≤~~[illegible]~~ µmho/cm at 25°C). Liquid wastes that cannot be processed to meet the quality requirement for reuse are solidified along with process concentrates for offsite shipment and disposal. Excess water is released in a controlled and monitored manner into the cooling tower blowdown line for dilution and then discharged to the Delaware River.

corresponding noble gas release rate of 500,000 μCi/s after 30 minutes decay (design basis).

The concentration of radioactivity at the point of discharge shall not exceed concentration limits specified in 10 CFR 20, on an annual average basis.

g. All piping and equipment in the LWMS are non-Seismic Category I with the exception of the primary containment.

The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the LWMS are discussed in Section 3.2.

h. Design features that reduce maintenance, equipment downtime, liquid leakage, or gaseous releases of radioactive materials to the building atmosphere, to facilitate cleaning or otherwise improve radwaste operations, are discussed in Section 12.3.

i. All atmospheric liquid radwaste tanks are provided with an overflow connection at least the size of the largest inlet connection. The overflow is connected below the tank vent and above the high level alarm setpoint. It is routed to the nearest drainage system compatible with its purity and chemical content. Each liquid radwaste tank room is designed to contain the maximum liquid inventory in case the tank ruptures.

j. Processed wastes are collected in sample tanks prior to their reuse as ~~condensate~~ DEMINERALIZED quality water or discharged in a controlled manner into the cooling tower blowdown line for dilution before entering the Delaware River.

k. The expected and maximum radionuclide activity inventories for LWMS components containing significant amounts of radioactive liquids are shown in Tables 11.2-8 and 11.2-9. They are based upon the assumptions given in Table 11.2-1 and upon the following:

10 μmho/cm and less than 20 ppm suspended solids) and are processed on a batch basis through a precoat filter and a mixed-bed demineralizer. Cross-connections with the floor drain subsystem allow processing through the floor drain filter and demineralizer.

The processed wastes are collected in one of the two waste sample tanks for chemical and radioactivity analysis. If acceptable, the tank contents are returned to the condensate storage tank (CST) for plant reuse. A recycle routing from the waste sample tank allows the sampled water that does not meet the DEMIN-ERALIZED WATER ~~condensate~~ quality requirements to be pumped back to a waste collector tank for additional processing by filtration and demineralization, or to the waste surge tank for transfer to and processing in the regenerant waste subsystem. If the plant condensate inventory is high, the sampled waste water is discharged to the cooling tower blowdown line for dilution prior to discharge to the Delaware River.

Additional collection capacity is also provided by a waste surge tank tied to the common inlet header of the waste collector tanks.

11.2.2.1.2 Floor Drain Processing System

The floor drain collector tanks receive low purity waste inputs from various floor drain, dirty radwaste (DRW), sumps in each plant enclosure and other inputs listed in Table 11.2-7. These wastes typically have a conductivity of 10 to 100 μmhos/cm, a maximum suspended solids concentration of 500 ppm, and a radioactivity concentration of less than 10^{-3} μCi/cc.

The floor drain subsystem consists of two floor drain collector tanks, a precoat filter, a mixed-bed demineralizer train, and two sample tanks. The wastes collected in the floor drain collector tank are processed on a batch basis. Cross-connections with the equipment drain subsystem also allow processing through the waste filter and demineralizer train.

The floor drain sample tanks collect the processed wastes, so that a sample may be taken for chemical and radioactivity analysis before discharge. The discharge path depends on the water quality, cooling tower blowdown availability, and plant water inventory. The treated floor drains may be discharged from the plant to the Delaware River after mixing with the cooling

tower blowdown. Off-standard quality water can be recycled to the floor drain collector tanks or to the waste neutralization tanks to be processed in the regenerant waste subsystem. If the treated wastes meet the standards for DEMINERALIZED ~~condensate~~ water ~~quality~~ used in the plant, and if the water inventory permits their recycle, the processed floor drain waste can be discharged to the CST for plant reuse.

11.2.2.1.3 Regenerant Waste Processing Subsystem

The regenerant waste subsystem collects wastes from the regeneration process for the condensate and radwaste demineralizers and the high conductivity drain sumps in the radwaste area of the auxiliary building and the turbine building. These wastes are collected in the waste neutralizer tanks, where they are neutralized and, if required, buffered with solutions of sodium phosphate before being processed through the waste evaporators for concentration. The distillate resulting from the evaporation process is returned to the waste collector tanks. The waste evaporator concentrate is collected in the concentrated waste tanks for chemical pretreatment and is transferred to the solid waste management system (SWMS) for solidification and offsite disposal. In addition, concentrate is transferred from the decontamination solution concentrated waste tank to the concentrated waste tanks.

11.2.2.1.4 Chemical Waste Processing Subsystem

Chemical wastes collected in the chemical waste tank consist of laboratory wastes, decontamination solutions, and sample rack drains. After accumulating in the chemical waste tank, these wastes are neutralized to a pH value of 7 to 10 and, if required, buffered with a solution of sodium phosphate, then processed by evaporation through the decontamination solution evaporator.

The chemical wastes are normally evaporated to reduce volume. The concentrate is discharged to the decontamination solution concentrated waste tank for radioactive decay, then transferred to the concentrated waste tanks. The vapors produced during this evaporation are sampled and discharged through the south plant vent. When the radioactivity concentration is low, a cross-connection with the floor drain subsystem allows the chemical wastes to be processed through the floor drain filter and demineralizer and then diluted with the cooling tower blowdown prior to discharge to the Delaware River.

11.2.3 RADIOACTIVE RELEASES

During liquid processing by the liquid waste management system (LWMS), radioactive contaminants are removed so that the bulk of the liquid is restored to DEMINERALIZED WATER QUALITY ~~condensate quality water~~, which is either returned to the condensate storage tank (CST) or discharged to the environment via the cooling tower blowdown line. The radioactivity removed from the liquid wastes is concentrated in the filter media, ion exchange resins, and evaporator bottoms. These concentrated wastes are sent to the solid waste management systems (SWMS) for further volume reduction and solidification. If the liquid is recycled to the plant, it meets the purity requirements for CST ~~condensate~~ makeup, as discussed in Section 9.2.3 ~~10.4.6~~. If the liquid is discharged, the activity concentration is consistent with the discharge criteria of 10 CFR 20. Tritiated water that is discharged from the systems is consistent with the discharge criteria of 10 CFR 20.

The resulting doses from radioactive effluents are within the guideline values of Appendix I of 10 CFR 50. In addition to the radioactivity limitations on releases, water quality standards for discharge and heat content may necessitate recycling of the water rather than discharging.

Although the plant discharges vary as stated above, this analysis assumes the following, consistent with NUREG-0016:

a. Discharge of 1% of the high purity waste processing stream

b. Discharge of 50% of the low purity waste processing stream

c. Discharge of 10% of the chemical waste processing stream

d. Discharge of 10% of the regenerant waste processing stream

e. Discharge of 100% of the laundry drain waste processing stream.

The assumptions and parameters used to calculate the yearly activity releases are given in Table 11.2-1. The yearly activity

PRIOR TO EXCEEDING TECHNICAL SPECIFICATION

e. Continuous monitoring is provided for all potential pathways of airborne radioactive releases, with main control room annunciation ~~at levels higher than~~ allowed limits.

f. Design provisions are incorporated that preclude the uncontrolled release of radioactivity to the environment as a result of any single operator error or any single active component failure.

g. The GWMS is designed to keep the exposure to plant personnel as low as is reasonably achievable (ALARA) during normal operation and plant maintenance, in accordance with Regulatory Guide 8.8.

h. The offgas system is designed to provide at least 35 days and 36 hours of delay time for xenon and krypton, respectively, at 75 scfm airflow rate.

i. The offgas system is designed in accordance with the guidelines of Regulatory Guide 1.143, with the exceptions described in Section 1.8.

j. Filtration units in the ventilation systems are designed, operated, and maintained in accordance with the guidelines of Regulatory Guide 1.140.

k. The offgas system is designed to maintain the concentration of hydrogen in the gases exhausted from the main condenser below flammable limits.

l. Instrumentation is provided in the offgas system to detect abnormal concentrations of hydrogen and other system malfunctions.

m. The offgas system is designed to withstand the effects of a hydrogen explosion without breach of the pressure boundary.

environmental ~~and seismic~~ conditions that can occur at its location and has been procured in conformance with a 10CFR Part 50, Appendix B quality assurance program.

The FRVSV RMS is powered from a battery backed uninterruptible ac power source.

Except as described above, the FRVSV-RMS components and functions are similar to the NPV and SPV-RMS components and functions.

FRVSV RMS calibration procedures are based on the requirements of the operation and maintenance manual supplied with the equipment. Calibration frequencies are provided in Chapter 16, "Technical Specifications."

11.5.2.2.4 Cooling Tower Blowdown Radiation Monitoring System

The cooling tower blowdown (CTB) RMS monitors a sample of the cooling tower blowdown before it is discharged to the Delaware River (Refer to Figure 10.4-3, Sh. 3). The high alarm indicates that abnormally high amounts of radioactive materials are being released to the environment; however, it is recognized that the seasonal natural content of potassium-40 in the river, after concentration in the cooling tower system, may cause upscale indication greater than actual plant releases. The CTB RMS has the same components as the liquid radwaste RMS (see Section 11.5.2.2.5), but the associated LRP does not provide a trip for valve closure or measure process flow rate.

11.5.2.2.5 Liquid Radwaste Radiation Monitoring System

The liquid radwaste RMS monitors the liquid radwaste sample for gamma radiation prior to discharge into the cooling tower blowdown line (Refer to Figure 11.2-2, Sheet 1). The liquid radwaste discharge is diluted by a continuous flow of water from the cooling tower basin prior to discharge into the Delaware River. A sample of the liquid radwaste discharge flows through the liquid radwaste RMS. The discharge system is described in more detail in Section 11.2.3.

Liquid radwaste can be discharged from any of several tanks collecting processed water. Prior to any release, the tank water is mixed thoroughly, sampled, and the sample is analyzed in the

TABLE 11.5-1

HOPE CREEK RADIATION MONITORING SYSTEMS

RMS Identification Description, and Ref.	Number of Channels	Detector Type(15)(16)	Detector Location(17)	Range(19)	Minimum Detectable Concentration(1)(19)
Main steam line 11.5.2.1.1 REN006A REN006B REN006C REN006D	4	Gamma ion chamber	Downstream of outboard MSIVs El. 137, Area 26	$1-10^{6}$ mR/h	1 mR/h(13)
Refueling floor exhaust 11.5.2.1.2 RE4856A RE4856B RE4856C	3	Beta-scint	Upstream of damper El. 205, Area 15	$2\times10^{-5}-2\times10^{-1}$ ~~$10^{-1}-10^{2}$~~ μC/cc Xe-133	2×10^{-5} ~~10^{-1}~~ μC/cc at 2.5 mR/hr MFP(7)
Reactor building exhaust 11.5.2.1.3 RE4857A RE4857B RE4857C	3	Beta-scint	Upstream of damper El. 189, Area 15	$2\times10^{-5}-2\times10^{-1}$ ~~$10^{-1}-10^{2}$~~ μci/cc Xe-133	2×10^{-5} [redacted] μC/cc at 2.5 mR/hr MFP(7)
Control room ventilation 11.5.2.1.4 RE4858C RE4858C1 RE4858D RE4858D1	2(21)	Beta-scint	Air inlet plena El. 162, Area 26	$5\times10^{-6}-2\times10^{-1}$ ~~$5\times10^{-8}-5$~~ μci/cc Kr-85	5×10^{-6} ~~5×10^{-8}~~ μC/cc at ~~2.5~~ 0.5 mR/hr MFP(7)
Drywell atmosphere post-accident 11.5.2.1.5 RE4825A RE4825B	2	Gamma ion chamber	Inside containment El. 145, Area 17	$1-10^{8}$ R/h	1 R/h(14) MFP(7)(10)

12.1.3.1.2 Station Procedures

Administrative requirements are implemented to ensure that applicable procedures developed by other plant disciplines have adequately incorporated the principle of minimizing personnel exposure. Station administrative documents describe the criteria for selection of those procedures and revisions that are reviewed by radiation protection. Recommendations made by radiation protection normally are resolved with the appropriate plant discipline prior to submission for final review and approval.

Procedures are subject to revision whenever improved techniques or increased safety are indicated.

12.1.3.2 Station Organization

As described in Section 12.5.1, the station organization provides the RADIATION PROTECTION/CHEMISTRY MANAGER ~~radiation protection engineer~~ with direct access to the general manager to ensure uniform support of radiation protection and ALARA requirements. This organization allows the general manager direct involvement in the review and approval of specific ALARA goals and objectives, as well as review of data and dissemination of information related to the ALARA program.

The station organization includes a senior radiological engineer who is free from routine radiation protection activities to implement the station ALARA program. This individual is primarily responsible for coordination of station ALARA activities and routinely interacts with first-line supervision in radiation work planning and post-job review.

12.1.3.3 Operating Experience

Experience gained during the operation of Salem Units 1 and 2, along with information from other boiling water reactors (BWRs), serves as the basis for procedures, techniques, and administration controls for HCGS. In addition, the radiation work permit process described in Section 12.5.3.2 provides a mechanism for collection and evaluation of data related to personnel exposure. Information collected by systems and/or components and job function assists in evaluating design or procedure changes intended to minimize future personnel radiation exposures.

and is responsible for all activities of the Technical Department.

The Technical Manager interfaces with the necessary and appropriate departments and personnel in the performance of the department activities.

The responsibilities of the Technical Department personnel are as follows:

a. Technical Engineer: The Technical Engineer is responsible for the areas of reactor engineering, technical reports and procedures, thermal performance, equipment reliability monitoring and testing, and document control. Reporting to the Technical Engineer are the Senior Reactor Supervisor, Senior Technical Supervisor and the Senior Reliability and Performance Supervisor. ~~The Senior Reactor Supervisor assumes authority and responsibility~~ in the absence of the Technical Engineer.

INSERT

b. Senior Reactor Supervisor: The Senior Reactor Supervisor is responsible for reactor engineering and thermal performance and equipment reliability monitoring. Engineers are assigned to the Senior Reactor Supervisor to develop and implement the details of the programs. The reactor engineering group assists the Power Ascension Manager in the development and implementation of initial criticality, low power physics and power ascension test programs and provides technical direction to the operating department for thermal and nuclear operation of the reactor and initial core loading and refueling operations. The reactor engineering group also monitors, collects, trends, and analyzes performance data for systems important to plant efficiency and reliability. The Senior Reactor Supervisor reports to the Technical Engineer.

c. Senior Technical Supervisor: The Senior Technical Supervisor is responsible for the administrative procedures, technical responses, and reports leaving the station in support of facility license and review of operating experiences. Reporting to the Senior Technical Supervisor are the staff engineers and the

INSERT FOR PAGE 13.1-28

the aforementioned Senior Supervisors assume the responsibility and authority of the Technical Engineer in their respective disciplines.

d. Senior Maintenance Supervisors: The Senior Maintenance Supervisors are responsible for assisting the Maintenance Engineer or I&C Engineer as applicable, in planning and executing maintenance repair and inspection activities. They are responsible for the effective use of materials and manpower while conducting maintenance and repairs. They direct the activities of the Nuclear Maintenance Supervisors. A Senior Nuclear Maintenance Supervisor, when so designated, will assume the authority and responsibilities of the Maintenance Engineer, or I&C Engineer, as applicable in his absence.

The Senior Nuclear Maintenance Supervisors' responsibilities include the following:

1. Scheduling and coordinating department work assignments
2. Preventive maintenance program
3. Corrective maintenance program
4. Technical Specification surveillance program
5. Support of initial startup program
6. Ensuring personnel certification is maintained

~~e. Senior Maintenance Planning Supervisor: The Senior Maintenance Planning Supervisor reports to the Maintenance Manager and assists the Maintenance Manager in the area of department administrative and planning functions. He is responsible for the maintenance history records, maintenance planning for both the daily and outage activities, inspection order implementation, obtaining material and vendor support, workload tracking, and interface with the Station Planning Manager.~~

a. A licensed senior reactor operator will be in the main control room area at all times when the unit is in operational Condition 1, 2, or 3.

b. A licensed reactor operator will be in the main control room at all times whenever there is fuel in the reactor.

c. The licensed senior reactor operator assigned to supervise core alterations in Condition 5 may have no concurrent operational duties.

d. If the Nuclear Shift Supervisor (NSS) position is not filled by an STA/SRO, a qualified shift technical advisor is required in operational Conditions 1, 2, and 3.

e. In addition to the Radiation Protection Technician required to be on shift whenever there is fuel in the reactor, all shift personnel will be trained in basic radiation protection.

f. Shift hours will be administratively controlled to ensure compliance with current NRC policy.

13.1.3 QUALIFICATION OF NUCLEAR PLANT PERSONNEL

13.1.3.1 Qualification Requirements

The qualification requirements for the onsite plant personnel are in accordance with Regulatory Guide 1.8 and ANSI/ANS 3.1-1981. The education, experience, and training requirements of the plant personnel meet the criteria of Section 4 of ANSI/ANS 3.1. ~~at the time of initial core load~~ Table 13.1-3 relates the plant staff positions to the corresponding positions of ANSI/ANS 3.1.

The General Manager may authorize deviations from a qualification requirement for subordinate positions when the combined education, experience, and managerial competency of an individual is judged sufficient to ensure adequate performance of designated responsibilities. Such judgement will be documented in writing and will not be used to degrade the staff overall qualification.

TABLE 13.1-3 (cont) Page 2 of 3

Hope Creek Operations Staff Position	ANSI/ANS-3.1 Equivalent
Senior Operating Technical Supervisor	Supervisor not requiring license
Senior Operating Support Supervisor	Supervisor not requiring license
Senior Reactor Supervisor	Reactor engineering
Senior Staff Maintenance Supervisor	Supervisor not requiring license
I&C technician	Technician
Senior Nuclear Maintenance Supervisor	Supervisor not requiring license
Nuclear Maintenance Supervisor	Supervisor not requiring license
Electrician	Maintenance personnel
Machinists	Maintenance personnel
Boiler repair mechanic	Maintenance personnel
Station mechanic	Maintenance personnel
Senior Radiation Protection Supervisor	Supervisor not requiring license(4)
Senior Radiological Engineer	Supervisor not requiring license(4)
Radiation Protection Supervisor	Supervisor not requiring license
Radiation protection technician	Technician
Radiation protection assistant	
Senior Chemistry Supervisor	Supervisor not requiring license
Senior Chemistry Staff Engineer	Supervisor not requiring license
Chemistry Supervisor	Supervisor not requiring license
Chemistry technician	Technician
MAINTENANCE STAFF ENGINEER	SUPERVISOR NOT REQUIRING LICENSE

TO BE SUPPLIED AT A LATER DATE

TECHNICAL ENGINEER

NAME; Thomas G. Busch

LICENSES AND CERTIFICATES:

Senior Reactor Operator License - Wm. H. Zimmer Nuclear Power Station SOP-10096

Certified Engineer in Training - State of Ohio

EDUCATION AND TRAINING:

1975	Bachelor of Science in Nuclear Engineering, 1975, University of Cincinnati, Cincinnati, Ohio
1976	Successfully completed a four week course of classroom and laboratory training dealing with operation of Honeywell 4000 series process computers. During the course process assembly language was learned along with operation and interfacing of the computer operating system and other software. The course was conducted by Honeywell.
1976	Successfully completed a five week course of classroom training concerning thermal hydraulic and nuclear characteristics of BWR cores of an engineering level. Thermal limit calculations and bases, core flow calibration, fuel preconditioning and process computer software were learned along with reactor integrated response to control changes. The course was conducted by the General Electric Company.
1976	Successfully completed a three week course consisting of classroom and laboratory training dealing with the BWR process computer NSSS software package. The methods employed in calculating core power distribution and thermal limits was learned. The course was conducted by The General Electric Company.

1977	Successfully completed an intensive twelve week course dealing with systems and operation of a BWR (Browns Ferry Unit 1) including approximately six weeks of simulator training, ultimately leading to SRO certification. The course was conducted by the General Physics Corporation at the TVA Power Production Training Center, Chattanooga, TN
1977	Completed a four week course consisting of approximately eighty hour of classroom review and eighty hours of observation of all facets of BWR operation. The course was conducted by the General Physics Corporation at the Browns Ferry Nuclear Power Station.
1978	Worked approximately two months during the period 6/78 to 11/78 at the Edwin I. Hatch Nuclear Power Plant. Served as shift test engineer during initial fuel loading. Participated in low power testing to approximately 30% power on Unit No. 2.
1980	During the period 2/24/80 to 3/15/80 worked with the Nuclear Engineering staff of the Monticello Nuclear Generating Station during the core alterations, control rod drive maintenance and fuel shuffling periods.
1980	During the period 3/31/80 to 4/9/80 worked with the Nuclear Engineering staff of the Monticello Nuclear Generating Plant during the plant startup following refueling to full power.
1980	Electrical Engineering Technology, twelve credit hours, Clermont Technical College, Batavia, Ohio
1981	Successfully completed a six day simulator course for Shift Technical Advisors conducted by General Electric at the Morris simulator.
1981	During the period of 3/21/81 to 3/15/81 participated in NRC evaluation of emergency operating procedures developed from BWROG guidelines and contingencies. Review

	conducted by NRC Procedures Testing Review Branch at the Morris simulator.
1981	Shift Technical Advisor Program, eighteen graduate credit hours, University of Cincinnati, Cincinnati, Ohio
1983	During the period of 1/6/83 to 3/11/83 participated in the reactor engineering activities at the Susquehanna Steam Electric Station. During that time SSES Unit 1 was undergoing power escalation testing from 30 to 100% power.
1983	INPO Technical Managers Workshop

EXPERIENCE:

	Public Service Electric and Gas Company Hope Creek Generating Station
1984 - Present	Technical Engineer responsible for program development and conduct of activities in the areas of reactor engineering, technical reports and procedures, thermal performance, equipment reliability monitoring and testing, and document control.
	Cincinnati Gas and Electric Company Wm. H. Zimmer Nuclear Power Station
1983 - 1984	Served as Superintendent of the Technical Support Division. Responsible for supervision of eight staff engineers and four engineers in training. Technical Support Division activities include: reactor engineering, computer engineering, coordination of preventive maintenance and surveillance testing programs, development of WPRD databases, and providing technical support to other departmental divisions.
1981 - 1983	Served as Technical Engineer, responsible for supervision of five engineers assigned to the reactor engineering and computer engineering groups. Also during this period, coordinated development of preventive maintenance and surveillance test scheduling, equipment

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	nameplate database, spare parts inventory, and commitment tracking computer based systems. Was also responsible for training of personnel and conducting drills for the Technical Support Center staff in preparation for a successfully completed emergency preparedness exercise.
1977 - 1981	Served as Reactor Engineer, responsible for preparation of core alteration, fuel handling, SNM accountability, core thermal limit surveillance, neutron monitoring equipment calibration and other station procedures. Primarily responsible for receipt of the initial core fuel. Assisted the Startup Coordinator with preparation of administrative controls, test implementing procedures and licensing submittals for the startup testing program. Assisted the plant Technical Engineer in preparation of plant Technical Specifications.
1975 - 1977	Served as Staff Engineer in the Technical Support Division. Prepared, reviewed and conducted system flushing and preoperational test procedures.
1972 - 1975	Served as Student Engineer in training at the Walter C. Beckjord station, a six unit pulverized coal generating plant. During this period worked in the maintenance, operations and technical staff departments on an alternating quarterly basis as part of the University of Cincinnati co-op student program.

NUCLEAR SHIFT SUPERVISOR

RIDDLE

NAME: Charles Randle ~~Ripple~~

MILITARY RECORD:

8/64 - 8/68	U.S.A.F. Hon. Disch. E-4 Aeromedical Evacuation - 2 years in Vietnam

EDUCATION:

Academic Diploma from Jeff Davis High School, Hazlehurst, GA

Georgia Southern College, Statesboro, GA 2 years credit toward BS in Biology.

Nuclear Power Plant Operator Training - 18 months

Nuclear Theory, BWR Technology, BOP System Analysis, Transient Analysis, System to System Interface, Browns Ferry Simulater, NRC Certified.

EXPERIENCE

1984 - Present	Public Service Electric and Gas - Hope Creek Generating Station - Nuclear Shift Supervisor.
5/1983 - 1984	Plant Operator, Georgia Power Company's E. Hatch Plant - Reported directly to Shift Supervisor and have as a minimum, the following responsibilities and authorities:

a. Responsible for operation and refueling in a safe manner under the direction of the Shift Supervisor.

b. Aids plant management and his immediate supervisors in carrying out the safe, reliable and efficient fuel loading, operation and maintenance of the plant.

INSERT THE RESUME OF WILLIAM J. MERRITT

SENIOR TECHNICAL SUPERVISOR

NAME: Elmer J. Galbraith

LICENSES AND CERTIFICATES:

U.S. Navy Qualification for Operation, Maintenance and Supervision of Naval Nuclear Propulsion Plants

EDUCATION

1957 - 1961	U.S. Naval Academy - Annapolis, MD BS (Engineering)
1961	U.S. Naval Submarine School
1964	U.S. Naval Nuclear Power School
1965	U.S. Naval Nuclear Propulsion Prototype Training
1973	U.S. Navy Poseidon Command Training
1976	U.S. Naval Nuclear Propulsion Plant Prospective Commanding Officer Training
1976	Submarine Prospective Commanding Officer Training

EXPERIENCE:

1984 - Present	Senior Technical Supervisor - Hope Creek Generating Station Public Service Electric & Gas Co. Responsible for program development and conduct of activities in the areas of technical specifications, technical document control, reporting requirements, surveillances, operating experience review and procedures.

SENIOR TECHNICAL SUPERVISOR

NAME:	William J. Merritt

LICENSING AND CERTIFICATES:

Engineer-in-Training (EIT), New Jersey

EDUCATION:

1976-1977	New Jersey Institute of Technology
1978-1980	Rensselaer Polytechnic Institute (BSME-1980)
1983-Date	Temple University Law School

EXPERIENCE:

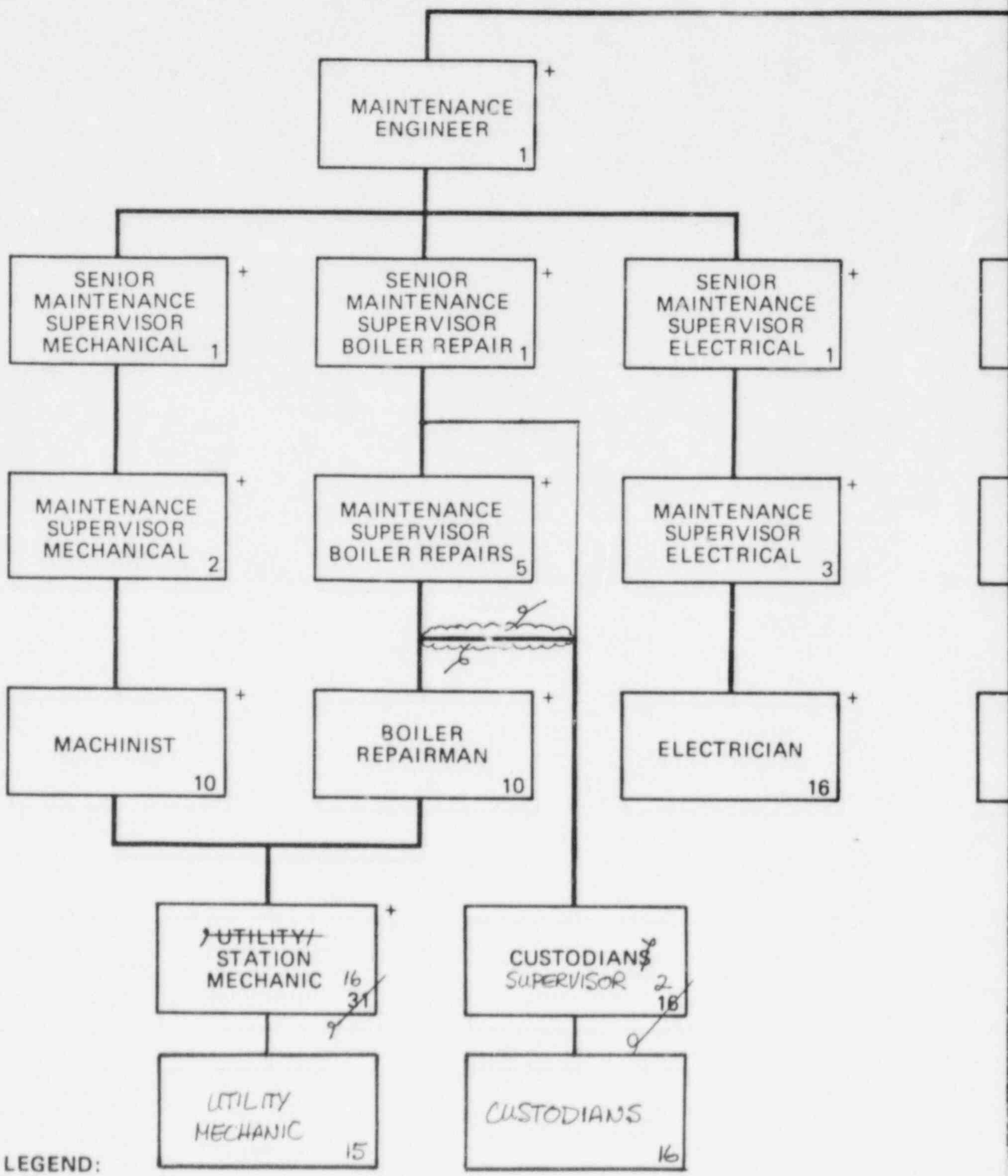
1985-Present	Senior Technical Supervisor - Hope Creek Generating Station, Public Service Electric and Gas Company. Responsible for program development and conduct of activities in the areas of technical specifications, technical document control, reporting requirements, surveillances, operating experience review and procedures.
1982-1985	Staff Engineer - Hope Creek Operations Operations Department Procedure Coordinator - Responsible for assuring that all procedures required to support fuel load are in place in a timely manner. This involves developing procedure guidelines consistent with regulatory requirements, coordinating the writing efforts of contract personnel, reviewing the various procedures, and interfacing with plant safety review groups.

	Technical Specification Reviewer - Responsible for the review of Hope Creek Draft Technical Specifications. As the prime reviewer for the Operations Department, this involves a detailed review of the FSAR/SER commitments, research into the plant design, interface with the architect-engineer and NSSS vendors.
1980-1982	Engineer - Stone and Webster Engineering Corporation
	Integrated Procedure Schedule Developer - Developed an integrated schedule for the development of all operational software (i.e., Operating Procedures, Maintenance Procedures, etc.) at the Nine Mile Point - Unit 2 Nuclear Station.
	Mechanical System Verifier - Performed preliminary as-built verification walkdowns of mechanical systems at the Oyster Creek Nuclear Station. Utilizing the information gained during the walkdowns, developed manhour estimates for the complete as-built verification program.
	Final Safety Analysis Reviewer - Reviewed the Nine Mile Point - Unit 2 FSAR against the NRC Standard Review Plan to ensure compliance prior to submittal to the Staff.
	System Description Writer - Prepared System Descriptions for mechanical and electrical systems at the Nine Mile Plant.
	Spare Parts Coordinator - Coordinated the identification, evaluation, and procurement of spare parts for the containment isolation valves at the Oyster Creek Nuclear Station.

1984	Acting Plant Manager for WNP-3, Washington Public Power Supply System With project in extended construction delay responsible for preservation of assets, preparation of operating procedures and support for licensing and engineering. Supervised 80 people in this effort. Maintained position as Technical & Startup Manager with a minimal activity startup effort.
1982 - 1984	Technical and Startup Manager for WNP-3, Washington Public Power Supply System. As Technical Manager, responsible for setting up department consisting of 25 plant engineers to report directly to the Plant Manager for plant support and performance. As Startup Manager responsible for startup of Combustion Engineering 1240 megawatt pressurized water reactor. Supervised and supported startup contractor in this effort.
1981 - 1982	Plant Management Training Program, Washington Public Power Supply System Participated in training program designed to meld naval nuclear propulsion experience with current nuclear utility practice and operations and meet the requirements of ANS 3.1 for plant management positions. The program consisted of: - Assignments to all project departments including construction, design engineering, quality assurance and licensing for a period of six months. - Plant training for six months at Southern California Edison's San Onofre nuclear generating station. Assigned to the Station Operations and Technical Managers for various periods as part of their working staffs. Participated in the startup effort of the Unit 2 Combustion Engineering Pressurized Water Reactor.

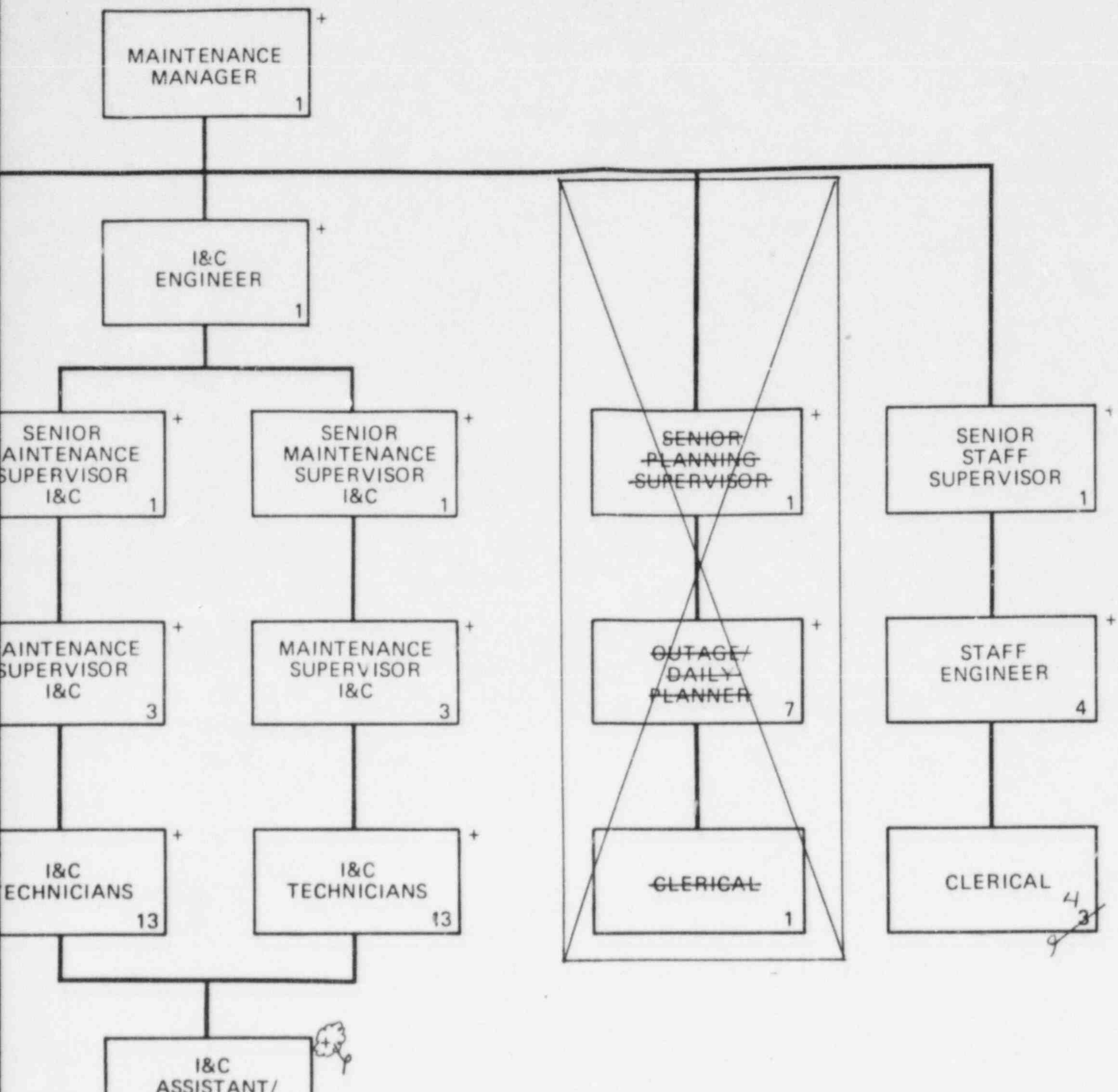
1979 - 1981	Tactics Training Department Director, FBM Submarine Training Center, Charleston, S.C.
	Responsible for operation, repair and maintenance of six major submarines training devices (Tactical, ship control and sonar). Supervised approximately 70 personnel in this effort. Conducted liaison between various contractor and government agencies in the installation and operation of these trainers. Involved in curriculum development.
1976 - 1979	Commanding Officer U.S.S. Ray (SSN653)
	Nuclear powered attack submarine based in Charleston, South Carolina with crew of 12 officers and 100 enlisted personnel. Duties encompassed complete spectrum of submarine operations including shipyard period and extended deployment operating at sea for several months without a logistic support base.
1973 - 1976	Executive Officer - U.S.S. Stonewall Jackson (SSBN634)
	Fleet ballistic missile submarine operating out of Holy Loch, Scotland, conducting strategic deterrent patrols. As second in command was responsible for the ship's operation and crew training and management. Supervised the movement of 120 crewmen from the off-crew training site, New London, CT. to the deployed site (Scotland) and back upon completion of the patrol. This cycle was repeated every six months.
1971 - 1973	Navigator, Main Propulsion Assistant, Weapons Officer - U.S.S. GATO (SSN615)
	Held department head level position, as listed, at various times aboard this nuclear powered attack submarine based in New London, Connecticut. Duties included at sea operations, pre-overhaul testing, 15 month shipyard overhaul at Ingalls Shipbuilding Corporation, Pascagoula, Miss. and post shipyard refresher training. During overhaul was extensively involved in the repairs and

	subsequent restart and testing of the reactor plant. While aboard completed certification as Engineer Officer by the Director, Division of Naval Reactors, U.S. Department of Energy.
1969 - 1971	Company Officer U.S. Naval Academy, Annapolis, MD. Supervised 100 midshipmen, monitored academic, physical and military training; conducted counseling; taught leadership; handled liaison between midshipmen/parents/congress.
1965 - 1969	Navigator, Main Propulsion Assistant, Weapons Officer, Training Officer, U.S.S. QUEENFISH (SSN651) Held department head level positions listed at various times aboard this first of a new class nuclear powered attack submarine based in Pearl Harbor, Hawaii. Duties included construction and initial startup testing at the building shipyard Newport News Shipbuilding and Drydock Company, Newport News, Virginia. Upon completion, ship transferred to the Pacific fleet where shakedown training and operations preceeded extended deployments at sea.
1962 - 1964	Engineer, Gunnery Officer, Supply Officer U.S.S. BARRACUDA (SST-3) Held department head level positions listed at various times aboard this diesel-electric submarine based in Key West, Florida. Duties included two extended shipyard periods including pre- and post-overhaul testing and local and deployed at-sea operations.



LEGEND:

+ POSITION REQUIRED TO MEET ANSI/ANS 3.1



HOPE CREEK GENERATING STATION
FINAL SAFETY ANALYSIS REPORT

MAINTENANCE DEPARTMENT
HOPE CREEK OPERATIONS

FIGURE 13.1-11 Amendment 13, 11/85

13.2.1.1.1 Cold License Training Program

This program is designed for NRC reactor operator (RO) and senior reactor operator (SRO) cold license candidates of varying backgrounds and experience. Candidates will be factored into the program at various points, depending on their previous experience and training. Testing and screening will be an intimate part of the overall training program. All license candidates who are supervisors HAVE ATTENDED ~~will attend~~ the PSE&G Technical Supervisory Skills Program and ~~will~~ meet the supervisory training requirements of ANSI/ANS-3.1-1981, Section 5.2.1.8. ~~prior to core load~~.

To assure the experience criteria of ANS 3.1 (1981) is met, as well as the general guidelines of NUREG-0094, additional experience will be provided by a structured observation program for all licensed operator candidates. A detailed description of this observation training is shown in Appendix 13K.

13.2.1.1.1.1 Senior Reactor Operator Training Program

The senior reactor operator (SRO) candidates will attend a training program consisting of, but not limited to, the following areas of instruction:

a. Nuclear Reactor Fundamentals

b. Reactor Startup Experience

c. Advanced technical training

d. Pre-Certification system training

e. BWR Cold certification training

f. In-plant training

g. Hope Creek Systems training

h. Pre-license examination testing and training

14.2.12.2 General Discussion of Startup Tests

All tests associated with the startup test phase are discussed in Section 14.2.12.3. For each test, a summary is presented defining the test objective, prerequisites, test method, and acceptance criteria. Test objectives identify those operating and safety-related characteristics of the plant that are involved in the test.

The operating power-flow map is presented as Figure 14.2-4. The test conditions are marked on Figure 14.2-4, and each test described in Section 14.2.12.3 is accomplished at the test conditions stated in Figure 14.2-5. These two figures represent the startup test schedule. The testing sequence generally runs from test condition 1 through test condition 6, with the exception that test condition 4 (natural circulation) is normally performed subsequent to the testing in test condition 6.

The startup test acceptance criteria are developed and approved by the design group organizations. In developing specific test acceptance criteria, the design groups will reference material such as:

a. FSAR Chapter 16, Technical Specifications

b. FSAR Chapter 15, Accident Analysis

c. Other FSAR sections

d. Vendor topical reports

e. Vendor technical documents

f. Design specifications

g. General Electric startup test specification.

The specific acceptance criteria will be listed in each startup test procedure. The criteria section of each test procedure has up to two sections, which are discussed below:

QUESTION 430.80 (SECTION 9.5.4)

In Section 9.5.4.2.1 you discuss the corrosion protection both internal and external for the fuel oil storage tank. No discussion is provided on the corrosion protection provided for the fuel oil fill piping. Expand the FSAR to include a more explicit description of proposed protection of underground piping. Where corrosion protective coatings are being considered (piping and tanks) include the industry standards which will be used in their application. Also discuss what provisions will be made in the design of the fuel oil storage and transfer system in the use of a impressed current type cathodic protection system, in addition to water proof protective coatings, to minimize corrosion of burried piping or equipment. If cathodic protection is not being considered, provide your justification. (SRP 9.5.4, Part II)

RESPONSE

The diesel fuel oil transfer piping that is buried is primed and wrapped, in accordance with industry standards, AWWA-C-203 including Appendix A1.5 and/or A2.0. The buried portions of the diesel fuel oil transfer piping are cathodically protected by an impressed current cathodic protection system. The impressed current cathodic protection system is also considered as a nonsafety-related system.

The diesel engine fuel oil transfer piping cathodic protection system will be tested and inspected per Maintenance Department preventive maintenance procedure MD-PM-QH-001 (Q) Cathodic Protection System P.M. ~~and the Technical Specifications.~~ The frequency and type of preventive maintenance activities are shown below:

2 Months

Rectifier unit will be visually inspected for physical damage and excessive heat. Output voltage and amperage will be recorded. (Adjustments made as needed). The interior and exterior of the unit will also be cleaned at this time.

12 Months

1. The anode test leads will be cleaned and verified to be adequately protected.

2. Performance test of underground portion of system to determine if protection is adequate.

The buried portion of the diesel fuel oil transfer piping is not considered safety-related piping since an emergency fill